The Union Light, Heat and Power Company
d/b/a Duke Energy Kentucky
Case No. 2006-00172
Forecasted Test Period Filing Requirements

RECEIVED
MAY 31 2006
PUBLIC SERVICE COMMISSION

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The Union Light, Heat and Power Company
d/b/a Duke Energy Kentucky
Case No. 2006-00172
Forecasted Test Period Filing Requirements
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Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
			filed with the commission.	
1	15	807 KAR 5:001 Section 10 (4)(c)	Except for sewer utilities, applicants with more than twenty (20) customers affected by the proposed general rate adjustment shall give the required notice by one (1) of the following methods: 1. A typewritten notice mailed to all customers no later than the date the application is filed with the commission; 2. Publishing the notice in a trade publication or newsletter which is mailed to all customers no later than the date on which the application is filed with the commission; or 3. Publishing the notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made within seven (7) days of the filing of the application with the commission.	Sandra P. Meyer
1	16	807 KAR 5:001 Section 10 (4)(d)	If notice is published, an affidavit from the publisher verifying that the notice was published, including the dates of the publication with an attached copy of the published notice, shall be filed with the Commission no later than forty-five (45) days of the filed date of the application.	Sandra P. Meyer
1	17	807 KAR 5:001 Section 10 (4)(e)	If notice is mailed, a written statement signed by the utility's chief officer in charge of Kentucky operations verifying the notice was mailed shall be filed with the Commission no later than thirty (30) days of the filed date of the application.	Sandra P. Meyer
1	18	807 KAR 5:001 Section 10 (4)(f)	All utilities, in addition to the above notification, shall post a sample copy of the required notification at their place of business no later than the date on which the application is filed which shall remain posted until the commission has finally determined the utility's rates.	Sandra P. Meyer
1	19	807 KAR 5:001 Section 10 (5)	Notice of hearing scheduled by the commission upon application by a utility for a general adjustment in rates shall be advertised by the utility by newspaper publication in the areas that will be affected in compliance with KRS 424.300.	Sandra P. Meyer
1	20	807 KAR 5:001 Section 10 (8)(a)	Financial data for forecasted period presented as pro forma adjustments to base period.	William Don Wathen, Jr.
1	21	807 KAR 5:001 Section 10 (8)(b)	Forecasted adjustments shall be limited to the 12 months immediately following the suspension period.	William Don Wathen, Jr.
1	22	807 KAR 5:001 Section 10 (8)(c)	Capitalization and net investment rate base shall be based on a 13 month average for the forecasted period.	William Don Wathen, Jr.

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			2. Estimated completion date; 3. Total estimated cost of construction by year exclusive and inclusive of Allowance for Funds Used During construction ("AFUDC") or Interest During construction Credit; and 4. Most recent available total costs incurred exclusive and inclusive of AFUDC or Interest During Construction Credit.	
1	32	807 KAR 5:001 Section 10 (9)(g)	For all construction projects constituting less than 5% of annual construction budget within 3 year forecast, file aggregate of information requested in paragraph (f) 3 and 4 of this subsection.	Jim L. Stanley John J. Roebel
1	33	807 KAR 5:001 Section 10 (9)(h)	Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying assumptions made in projecting results of operations and including the following information: 1. Operating income statement (exclusive of dividends per share or earnings per share); 2. Balance sheet; 3. Statement of cash flows; 4. Revenue requirements necessary to support the forecasted rate of return; 5. Load forecast including energy and demand (electric); 6. Access line forecast (telephone); 7. Mix of generation (electric); 8. Mix of gas supply (gas); 9. Employee level; 10.Labor cost changes; 11.Capital structure requirements; 12.Rate base; 13.Gallons of water projected to be sold (water); 14.Customer forecast (gas, water); 15.MCF sales forecasts (gas); 16.Toll and access forecast of number of calls and number of minutes (telephone); and 17.A detailed explanation of any other information provided.	Brian P. Davey Lynn J. Good #6, #13, #16 & #17 Not applicable
1	34	807 KAR 5:001 Section 10 (9)(i)	Most recent FERC or FCC audit reports.	Dwight L. Jacobs
1	35	807 KAR 5:001 Section 10 (9)(j)	Prospectuses of most recent stock or bond offerings.	Lynn J. Good
1	36	807 KAR 5:001 Section 10 (9)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or the Automated Reporting Management Information System Report (telephone) and PSC Form T (telephone).	Dwight L. Jacobs
2	37	807 KAR 5:001 Section 10 (9)(l)	Annual report to shareholders or members and statistical supplements for the most recent 5 years prior to application filing date.	Dwight L. Jacobs

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d/b/a Duke Energy Kentucky
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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT
OF ELECTRIC RATES OF THE UNION
LIGHT, HEAT AND POWER COMPANY
D/B/A DUKE ENERGY KENTUCKY

CASE NO. 2006- 00172

FILING REQUIREMENTS

VOLUME 1

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT
OF ELECTRIC RATES OF THE UNION
LIGHT, HEAT AND POWER COMPANY
D/B/A DUKE ENERGY KENTUCKY

CASE NO. 2006- 00172

FILING REQUIREMENTS

VOLUME 1

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
KRS 278.180

KRS 278.180

Description of Filing Requirement:

Thirty-day notice of rates to Kentucky Public Service Commission.

Response:

See attached.

Sponsoring Witness: Sandra P. Meyer

Duke Energy®

SANDRA P. MEYER
President

Duke Energy Ohio
Duke Energy Kentucky
139 East Fourth Street
Cincinnati, OH 45202

513 419 5499
513 419 5470 fax
513 706 1065 cell
spmeyer@duke-energy.com

RECEIVED
APR 27 2006
PUBLIC SERVICE COMMISSION

VIA OVERNIGHT MAIL

April 26, 2006

Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: Notice of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky's Intent to File a General Electric Rate Case Case No. 2006-00172

Dear Ms. O'Donnell:

The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky ("Duke Energy Kentucky") notifies the Commission that it will file a general electric rate case in four weeks or reasonably soon thereafter.[1] Duke Energy Kentucky will use a forward-looking test period for this case.

The Commission has ordered Duke Energy Kentucky to file its next general electric rate case such that, based on the applicable suspension period, the new rates will become effective January 1, 2007.[2] We must file our application in late May 2006 to meet this requirement.[3]

We are providing a copy of this notice to the Attorney General's Utility Intervention and Rate Division and to counsel for the other intervenors in our last general electric rate case. We will work diligently with the Commission and our other stakeholders to seek a constructive resolution. Thank you for your consideration.

Sincerely,

Sandra P Meyer

Sandra P. Meyer
President, Duke Energy Kentucky

---

1 Duke Energy Kentucky provides this notice pursuant to Commission regulation 807 KAR 5:001 Section 10(2).
2 *See* Finding No. 15 of the Commission's December 5, 2003 Order in Case No. 2003-00252.
3 This late May 2006 application filing date is required by: (1) the Commission's Order to effectuate new rates by January 1, 2007; (2) the 30-day notice period for new rates under KRS 278.180; and (3) the six-month suspension period for forward-looking test period cases under KRS 278.190.

SPM/sew

cc: Chairman Mark David Goss (via overnight mail)
Vice Chairman Theresa J. Hill (via overnight mail)
Commissioner W. Gregory Coker (via overnight mail)
Hon. Gregory D. Stumbo (via overnight mail)
Hon. Dennis G. Howard (via overnight mail)
Hon. Elizabeth E. Blackford (via overnight mail)
Hon. David F. Boehm (via overnight mail)
Hon. Michael L. Kurtz (via overnight mail)
Hon. Anthony G. Martin (via overnight mail)
Hon. Carl J. Melcher (via overnight mail)

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 8(1)

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807 KAR 5:001, SECTION 8(1)

Description of Filing Requirement:

Full name and P.O. address of applicant and reference to the particular provision of law requiring Kentucky Public Service Commission approval.

Response:

See notice and statement.

Sponsoring Witness: Sandra P. Meyer

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 8(2)

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807 KAR 5:001, SECTION 8 (2)

Description of Filing Requirement:

The original and 10 copies of application plus copy for anyone named as interested party.

Response:

Original and 10 copies filed with the Kentucky Public Service Commission. Copies provided to interested parties listed on the Certificate of Service.

Sponsoring Witness: Sandra P. Meyer

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(1)(b)(1)

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807 KAR 5:001, SECTION 10(1)(b)(1)

Description of Filing Requirement:

Statement of the reason the adjustment is required.

Response:

The primary reason for this requested rate increase is summarized by a review of the forecasted test period, the twelve months ending December 31, 2007, which indicates that the earned rate of return on capitalization obtained from the electric operations of Duke Energy Kentucky is 3.68%. By any reasonable measure, this level of earned return is insufficient to ensure the continued reliable and safe provision of electric service to Duke Energy Kentucky's customers.

Duke Energy Kentucky's present electric rates and charges, which are based on costs incurred during the twelve months ended July 31, 1991, were authorized by this Commission by Order dated May 5, 1992, and rehearing Order dated June 11, 1992, in Case No. 91-370.

Between August 1, 1991, and the valuation date in this case, Duke Energy Kentucky's investment in transmission and distribution facilities required to provide safe and reliable electric service to customers will have more than doubled. In addition, Duke Energy Kentucky obtained generating assets ("the plants") from Duke Energy Ohio ("DEO") on January 1, 2006, at the net book value of approximately $399 million. Duke Energy Kentucky should be allowed to earn a return on the additional capital required to fund these substantial increases in plant over this 16-year period.

Other operating costs, exclusive of the cost of fuel, purchased power, and emission allowances have increased by approximately $75 million on an annual basis. Duke Energy Kentucky expects to incur emission allowance costs of $5 million and incremental transmission costs associated with the Midwest ISO's Day 2 market of $12 million. As a direct result of the increased capital investment, depreciation expense has increased by approximately $29 million on an annual basis, and taxes other than income taxes have increased by over $5 million. The projected fuel cost component of base rates has increased approximately $20 million dollars over the amount currently reflected in Duke Energy Kentucky's fuel rate which has been frozen since 2001.

Additionally, Duke Energy Kentucky was ordered by the Commission in Case No. 2003-00252 to file this application for rates to be effective January 1, 2007. The purpose of this case is to allow Duke Energy Kentucky the opportunity to recover its current costs to operate its electric utility system in a safe and reliable manner and including a fair return on the investment made to serve customers sufficient to maintain financial integrity, to attract capital, and to compensate shareholders for the use of their capital.

Sponsoring Witness: Paul G. Smith

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(1)(b)(2)

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807 KAR 5:001, SECTION 10(1)(b)(2)

Description of Filing Requirement:

A statement that the utility's annual reports, including the annual report for the most recent calendar year, are on file with the commission in accordance with 807 KAR 5:006, Section 3(1)

Response:

Duke Energy Kentucky certifies that its annual reports are on file with the Commission in accordance with 807 KAR 5:006, Section (3)(1). Its most recent annual report for the year ending 2005 was filed with the Commission on March 31, 2006.

DJacobs

Dwight L. Jacobs
Vice President and Controller
Franchised Electric & Gas Operations
Duke Energy Corporation

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(1)(b)(3)

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807 KAR 5:001, SECTION 10(1)(b)(3)

Description of Filing Requirement:

A certified copy of the utility's articles of incorporation.

Response:

A certified copy of Duke Energy Kentucky's Articles of Incorporation and amendments thereto is on file with the Commission in Case No. 2005-00042, styled *"In The Matter of An Adjustment of Gas Rates of The Union Light, Heat and Power Company."*

Sponsoring Witness: Sandra P. Meyer

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(1)(b)(5)

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807 KAR 5:001, SECTION 10(1)(b)(5)

Description of Filing Requirement:

If the utility is incorporated or is a limited partnership, a certificate of good standing or certificate of authorization dated within sixty (60) days of the date the application is filed.

Response:

See attached.

Sponsoring Witness: Sandra P. Meyer

Commonwealth of Kentucky
Trey Grayson
Secretary of State

Certificate of Existence

I, Trey Grayson, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

THE UNION LIGHT, HEAT AND POWER COMPANY

is a corporation duly incorporated and existing under KRS Chapter 271B, whose date of incorporation is March 20, 1901 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that articles of dissolution have not been filed; and that the most recent annual report required by KRS 271B.16-220 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 1st day of May, 2006.

Certificate Number: 30391
Jurisdiction: CT Corporation
Visit http://apps.sos.ky.gov/business/obdb/certvalidate.aspx to validate the authenticity of this certificate.

COMMONWEALTH OF KENTUCKY
OFFICE OF SECRETARY OF STATE

Trey Grayson
Secretary of State
Commonwealth of Kentucky
30391/0052929

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(1)(b)(4)

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807 KAR 5:001, SECTION 10(1)(b)(4)

Description of Filing Requirement:

If the utility is a limited partnership, a certified copy of the limited partnership agreement and all amendments thereto or out-of-state documents of similar import. If the utility's limited partnership agreement and amendments have already been filed with the commission in a prior proceeding, the application may state this fact making reference to the style and case number of the prior proceeding

Response:

Duke Energy Kentucky is a corporation; therefore, this requirement does not apply.

Sponsoring Witness: Sandra P. Meyer

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(1)(b)(6)

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807 KAR 5:001, SECTION 10(1)(b)(6)

Description of Filing Requirement:

A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that such a certificate is not necessary.

Response:

See attached.

Sponsoring Witness: Sandra P. Meyer

COMMONWEALTH OF KENTUCKY

Trey Grayson
Secretary of State

Certificate

I, Trey Grayson, Secretary of State for the Commonwealth of Kentucky, do hereby certify that the foregoing writing has been carefully compared by me with the original thereof, now in my official custody as Secretary of State and remaining on file in my office, and found to be a true and correct copy of

CERTIFICATE OF ASSUMED NAME OF

DUKE ENERGY BEING ADOPTED BY THE UNION LIGHT, HEAT AND POWER COMPANY FILED MARCH 7, 2006.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 18th day of May, 2006.

513 621 0116

COMMONWEALTH OF KENTUCKY
TREY GRAYSON
SECRETARY OF STATE

0052929.04
Ghance
ADD
Trey Grayson
Secretary of State
Received and Filed
03/07/2006 12:55:56 PM
Fee Receipt: $20.00

CERTIFICATE OF ASSUMED NAME

This certifies that the assumed name of

Duke Energy
(Name under which the business will be conducted)

has been adopted by The Union Light, Heat and Power Company
(Real name - KRS 365.015(1))

which is the "real name" of (YOU MUST CHECK ONE)

- [ ] a Domestic General Partnership
- [ ] a Domestic Registered Limited Liability Partnership
- [ ] a Domestic Limited Partnership
- [ ] a Domestic Business Trust
- [x] a Domestic Corporation
- [ ] a Domestic Limited Liability Company
- [ ] a Joint Venture
- [ ] a Foreign General Partnership
- [ ] a Foreign Registered Limited Liability Partnership
- [ ] a Foreign Limited Partnership
- [ ] a Foreign Business Trust
- [ ] a Foreign Corporation
- [ ] a Foreign Limited Liability Company

organized and existing in the state or country of Kentucky, and whose address is

139 E. 4th Street, Cincinnati, Ohio 45202
Street address, if any — City — State — Zip Code

The certificate of assumed name is executed by

Richard G. Beach
Signature

Richard G. Beach, Asst. Secretary
Print or type name and title

3-2-06
Date

Signature

Print or type name and title

Date

COMMONWEALTH OF KENTUCKY

Trey Grayson
Secretary of State

Certificate

I, Trey Grayson, Secretary of State for the Commonwealth of Kentucky, do hereby certify that the foregoing writing has been carefully compared by me with the original thereof, now in my official custody as Secretary of State and remaining on file in my office, and found to be a true and correct copy of

CERTIFICATE OF ASSUMED NAME OF
DUKE ENERGY KENTUCKY, INC. ADOPTED BY THE UNION LIGHT, HEAT AND POWER COMPANY FILED MARCH 3, 2006.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 2nd day of May, 2006.

COMMONWEALTH OF KENTUCKY
TREY GRAYSON
SECRETARY OF STATE

0052929.04 AMcRay ADD

Trey Grayson
Secretary of State
Received and Filed
03/03/2006 1:20:00 PM
Fee Receipt: $20.00

CERTIFICATE OF ASSUMED NAME

This certifies that the assumed name of

Duke Energy Kentucky, Inc.
[Name under which the business will be conducted]

has been adopted by The Union Light, Heat and Power Company
[Real name - KRS 365.015(1)]

which is the "real name" of [YOU MUST CHECK ONE]

- [ ] a Domestic General Partnership
- [ ] a Domestic Registered Limited Liability Partnership
- [ ] a Domestic Limited Partnership
- [ ] a Domestic Business Trust
- [x] a Domestic Corporation
- [ ] a Domestic Limited Liability Company
- [ ] a Joint Venture
- [ ] a Foreign General Partnership
- [ ] a Foreign Registered Limited Liability Partnership
- [ ] a Foreign Limited Partnership
- [ ] a Foreign Business Trust
- [ ] a Foreign Corporation
- [ ] a Foreign Limited Liability Company

organized and existing in the state or country of Kentucky, and whose address is

139 E. 4th Street, Cincinnati, Ohio 45202
Street address, if any — City — State — Zip Code

The certificate of assumed name is executed by

Richard G. Beach
Signature

Richard G. Beach, Asst. Secretary
Print or type name and title

3-2-06
Date

Signature

Print or type name and title

Date

SSC-226 (7/98) (See attached sheet for instructions)

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(1)(b)(7)

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807 KAR 5:001, SECTION 10(1)(b)(7)

Description of Filing Requirement:

The proposed tariff in a form which complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed.

Response:

The proposed tariffs are at Schedule L-1.

Sponsoring Witness: Jeffrey R. Bailey

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(1)(b)(8)

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807 KAR 5:001, SECTION 10(1)(b)(8)

Description of Filing Requirement:

The utility's proposed tariff changes, identified in compliance with 807 KAR 5:011, shown either by:

a. Providing the present and proposed tariffs in comparative form on the same sheet side by side or on facing sheets side by side; or

b. Providing a copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions.

Response:

The proposed tariff changes are at Schedule L-2.1 (current tariffs with proposed additions in red-line format and underscored with strike-through of proposed deletions) and Schedule L-2.2 red-lined version of proposed tariffs.

Sponsoring Witness: Jeffrey R. Bailey

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(1)(b)(9)

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807 KAR 5:001, SECTION 10(1)(b)(9)

Description of Filing Requirement:

A statement that customer notice has been given in compliance with subsections (3) and (4) of this section with a copy of the notice.

Response:

See attached.

Sponsoring Witness: Sandra P. Meyer

SANDRA P. MEYER
President

Duke Energy Ohio
Duke Energy Kentucky
139 East Fourth Street
Cincinnati, OH 45202

513 419 5499
513 419 5470 fax
513 706 1065 cell
spmeyer@duke-energy.com

RECEIVED
APR 27 2006
PUBLIC SERVICE COMMISSION

VIA OVERNIGHT MAIL

April 26, 2006

Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: Notice of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky's Intent to File a General Electric Rate Case

Case No. 2006-00172

Dear Ms. O'Donnell:

The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky ("Duke Energy Kentucky") notifies the Commission that it will file a general electric rate case in four weeks or reasonably soon thereafter.[1] Duke Energy Kentucky will use a forward-looking test period for this case.

The Commission has ordered Duke Energy Kentucky to file its next general electric rate case such that, based on the applicable suspension period, the new rates will become effective January 1, 2007.[2] We must file our application in late May 2006 to meet this requirement.[3]

We are providing a copy of this notice to the Attorney General's Utility Intervention and Rate Division and to counsel for the other intervenors in our last general electric rate case. We will work diligently with the Commission and our other stakeholders to seek a constructive resolution. Thank you for your consideration.

Sincerely,

Sandra P Meyer

Sandra P. Meyer
President, Duke Energy Kentucky

---

[1] Duke Energy Kentucky provides this notice pursuant to Commission regulation 807 KAR 5:001 Section 10(2).

[2] *See* Finding No. 15 of the Commission's December 5, 2003 Order in Case No. 2003-00252.

[3] This late May 2006 application filing date is required by: (1) the Commission's Order to effectuate new rates by January 1, 2007; (2) the 30-day notice period for new rates under KRS 278.180; and (3) the six-month suspension period for forward-looking test period cases under KRS 278.190.

SPM/sew

cc: Chairman Mark David Goss (via overnight mail)
Vice Chairman Theresa J. Hill (via overnight mail)
Commissioner W. Gregory Coker (via overnight mail)
Hon. Gregory D. Stumbo (via overnight mail)
Hon. Dennis G. Howard (via overnight mail)
Hon. Elizabeth E. Blackford (via overnight mail)
Hon. David F. Boehm (via overnight mail)
Hon. Michael L. Kurtz (via overnight mail)
Hon. Anthony G. Martin (via overnight mail)
Hon. Carl J. Melcher (via overnight mail)

CERTIFICATE OF NOTICE TO THE PUBLIC OF CHANGE IN TARIFF WHICH RESULTS IN INCREASED RATES

To the Public Service Commission, Frankfort, Ky.

Pursuant to the Rules Governing Tariffs, I hereby certify that I am President of The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio ("Duke Energy Ohio") and President of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, a utility furnishing gas and electric service within the Commonwealth of Kentucky, which on or about the 31st day of May, 2006 issued its new Electric Tariff KY.P.S.C. No. 1, cancelling its former Electric Tariff KY.P.S.C. No. 1, to become effective July 1, 2006 and that notice to the public of the issuing of the same is being given in all respects as required by Section 8 of said administrative regulation, as follows:

On the 31st day of May, 2006, the same will be exhibited for public inspection at the offices and places of business of the Company in the territory affected thereby, to wit, at the following places: 1697A Monmouth Street, Newport, Kentucky 41071, and that the same will be kept open to public inspection at said offices and places of business in conformity with the requirements of Section 8 of said administrative regulation.

That more than 20 customers will be affected by said change by way of an increase in their rates or charges, and on or about the 31st day of May, 2006 there will be delivered to the Kentucky Enquirer and Kentucky Post, newspapers of general circulation in the communities in which the customers affected reside, for publication therein once a week for three consecutive weeks prior to the effective date of said change, a notice of the proposed rates or administrative regulations, a copy of said notice being attached hereto. A certificate of the publication of said notice will be furnished to the Public Service Commission upon the completion of the same in accordance with Section 9(2), of said administrative regulation.

Given under my hand this 25 day of May, 2006

S. Meyer

Sandra P. Meyer
President, Duke Energy Ohio
President, Duke Energy Kentucky
139 East Fourth Street
P.O. Box 960
Cincinnati, Ohio 45201-0960

#185911

NOTICE

The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc. ("Duke Energy Kentucky" or "Company") hereby gives notice that it seeks approval by the Kentucky Public Service Commission of an adjustment of electric rates to become effective on and after July 1, 2006. The Commission has docketed this proceeding as Case No. 2006-00172. The proposed electric rates are applicable to the following communities:

Alexandria	Elsmere	Ludlow
Bellevue	Erlanger	Melbourne
Boone County	Fairview	Newport
Bromley	Florence	Park Hills
Campbell County	Fort Mitchell	Pendleton County
Cold Spring	Fort Thomas	Ryland Heights
Covington	Fort Wright-Lookout Heights	Silver Grove
Crescent Park	Grant County	Southgate
Crescent Springs	Highland Heights	Taylor Mill
Crestview	Independence	Union
Crestview Hills	Kenton County	Villa Hills
Crittenden	Kenton Vale	Visalia
Dayton	Lakeside Park	Walton
Dry Ridge	Lakeview	Wilder
Edgewood	Latonia Lakes	Woodlawn

DUKE ENERGY KENTUCKY PRESENT AND PROPOSED RATES

Residential Service – Rate RS
(Electric Tariff Sheet No. 30)

Current Rate
Customer Charge $3.73 per month
Energy Charge
Summer Rate
First 1,000 kilowatt-hours 6.562¢ per kWh
Additional kilowatt-hours 6.873¢ per kWh
Winter Rate
First 1,000 kilowatt-hours 6.562¢ per kWh
Additional kilowatt-hours 5.059¢ per kWh

Proposed Rate
Customer Charge $5.00 per month
Energy Charge
All kilowatt-hours $0.061299 per kWh

Service at Secondary Distribution Voltage – Rate DS
(Electric Tariff Sheet No. 40)

Current Rate
Customer Charge per month
Single Phase Service $5.00 per month
Three Phase Service $10.00 per month
Demand Charge
First 15 kilowatts $0.00 per kW
Additional kilowatts $6.53 per kW
Energy Charge
First 6,000 kWh 6.896¢ per kWh
Next 300 kWh/kW 4.210¢ per kWh
Additional kWh 3.497¢ per kWh
Standard "Cap" Rate 19.033¢ per kWh
Church "Cap" Rate 11.295¢ per kWh

Proposed Rate
Customer Charge per month
Single Phase Service $7.50 per month
Three Phase Service $15.00 per month
Demand Charge
First 15 kilowatts $0.00 per kW
Additional kilowatts $8.00 per kW
Energy Charge
First 6,000 kWh $0.060731 per kWh
Next 300 kWh/kW $0.049510 per kWh
Additional kWh $0.040922 per kWh
Standard "Cap" Rate $0.235249 per kWh
Church "Cap" Rate $0.139607 per kWh

Time-of-Day Rate for Service at Distribution Voltage – Rate DT
(Electric Tariff Sheet No. 41)

Current Rate
Customer Charge
Single Phase $5.00 per month
Three Phase $10.00 per month
Primary Voltage Service $100.00 per month
Demand Charge
Summer
On Peak kW $9.71 per kW
Off Peak kW $1.00 per kW
Winter
On Peak kW $8.03 per kW
Off Peak kW $1.00 per kW
Energy Charge
All kWh 3.519¢ per kWh
Primary Voltage Discount:
First 1,000 kW of On Peak billing demand at $0.50 per kW.
Additional kW of On Peak billing demand at $ 0.35 per kW.

Proposed Rate
Base Rate
Customer Charge
Single Phase $7.50 per month
Three Phase $15.00 per month
Primary Voltage Service $100.00 per month
Demand Charge
Summer
On Peak kW $11.56 per kW
Off Peak kW $1.19 per kW
Winter
On Peak kW $10.15 per kW
Off Peak kW $1.19 per kW
Energy Charge
All kWh $0.041927 per kWh
Primary Voltage Discount:
First 1,000 kW of On Peak billing demand at $0.65 per kW.
Additional kW of On Peak billing demand at $0.50 per kW.

Optional Rate for Electric Space Heating – Rate EH
(Electric Tariff Sheet No. 42)

Current Rate
A. Winter Period
Customer Charge
Single Phase Service $5.00 per month
Three Phase Service $10.00 per month
Primary Voltage Service $100.00 per month
Demand Charge
All kW $0.00 per kW
Energy Charge
All kWh 5.150¢ per kWh
B. Summer Billing Period
For energy used during the summer period, the kilowatt demand and kilowatt-hour use shall be billed in accordance with the provisions of the applicable Rate DS or Rate DP.

Proposed Rate
A. Winter Period
Customer Charge
Single Phase Service $7.50 per month
Three Phase Service $15.00 per month
Primary Voltage Service $100.00 per month
Energy Charge
All kWh $0.067222 per kWh
B. Summer Billing Period
For energy used during the summer period, the kilowatt demand and kilowatt-hour use shall be billed in accordance with the provisions of Rate DS or Rate DP.

Seasonal Sports Service – Rate SP
(Electric Tariff Sheet No. 43)

Current Rate
Customer Charge $5.00 per month
Energy Charge 8.590¢ per kWh
A charge of $10.00 is applicable to each season to cover in part the cost of reconnection of service.

Proposed Rate
Customer Charge $7.50 per month
Energy Charge $0.093751 per kWh
A charge of $25.00 is applicable to each season to cover in part the cost of reconnection of service.

Optional Unmetered General Service Rate For Small Fixed Loads – Rate GS-FL
(Electric Tariff Sheet No. 44)

Current Rate
For loads based on a range of 540 to 720 hours use per month of the rated capacity of the connected equipment: 6.791¢ per kWh
For loads of less than 540 hours use per month of the rated capacity of the connected equipment: 7.828¢ per kWh
Minimum: $2.50 per Fixed Load Location per month.

Proposed Rate
For loads based on a range of 540 to 720 hours use per month of the rated capacity of the connected equipment $0.070656 per kWh
For loads of less than 540 hours use per month of the rated capacity of the connected equipment $0.081562 per kWh
Minimum: $2.69 per Fixed Load Location per month.

Service at Primary Distribution Voltage Applicability – Rate DP
(Electric Tariff Sheet No. 45)

Current Rate
Customer Charge per month
Primary Voltage Service (12.5 or 34.5 kV) $100.00 per month
Demand Charge
All kilowatt $6.08 per kW
Energy Charge
First 300 kWh 4.252¢ per kWh
Additional kWh 3.510¢ per kWh

Proposed Rate
Customer Charge per month
Primary Voltage Service (12.5 or 34.5 kV) $100.00 per month
Demand Charge
All kilowatts $7.50 per kW
Energy Charge
First 300 kWh $0.051707 per kWh
Additional kWh $0.043446 per kWh

Time-of-Day Rate for Service at Transmission Voltage – Rate TT
(Electric Tariff Sheet No. 51)

Current Rate
Customer Charge per month $500.00 per month
Demand Charge
Summer
On Peak kW $6.52 per kW
Off Peak kW $1.00 per kW
Winter
On Peak kW $5.33 per kW
Off Peak kW $ 1.00 per kW
Energy Charge
All kWh 3.485¢ per kWh

Proposed Rate
Customer Charge per month $500.00 per month
Demand Charge
Summer
On Peak kW $7.29 per kW
Off Peak kW $1.11 per kW
Winter
On Peak kW $5.98 per kW
Off Peak kW $1.11 per kW
Energy Charge
All kWh $0.038697 per kWh

Generation Support Service – Rider GSS
(Electric Tariff Sheet No. 58)

Current Rate
1. Administrative Charge $50.00 per month
2. Monthly Distribution Reservation Charge
a. Rate DS – Secondary Distribution Service $2.9056 per kW
b. Rate DT – TOU Secondary Distribution Service $2.9056 per kW
c. Rate DP – Primary Distribution Service $2.1570 per kW
d. Rate TT – Transmission Service $0.4440 per kVA
3. Monthly Transmission Reservation Charge
a. Rate DS – Secondary Distribution Service $1.0230 per kW
b. Rate DT – TOU Secondary Distribution Service $1.0230 per kW
c. Rate DP – Primary Distribution Service $1.1990 per kW
d. Rate TT – Transmission Service $1.2480 per kVA
4. Monthly Ancillary Services Reservation Charge
a. Rate DS – Secondary Distribution Service $0.5240 per kW
b. Rate DT – TOU Secondary Distribution Service $0.5240 per kW
c. Rate DP – Primary Distribution Service $0.5240 per kW
d. Rate TT – Transmission Service $0.4550 per kVA

Proposed Rate
1. Administrative Charge $50.00 per month
2. Monthly Distribution Reservation Charge
a. Rate DS – Secondary Distribution Service $2.6893 per kW
b. Rate DT – TOU Secondary Distribution Service $2.4716 per kW
c. Rate DP – Primary Distribution Service $2.6819 per kW
d. Rate TT – Transmission Service $0.00 per kVA
3. Monthly Transmission Reservation Charge
a. Rate DS – Secondary Distribution Service $1.3153 per kW
b. Rate DT – TOU Secondary Distribution Service $1.3097 per kW
c. Rate DP – Primary Distribution Service $1.6710 per kW
d. Rate TT – Transmission Service $1.2355 per kVA
4. Monthly Ancillary Services Reservation Charge
a. Rate DS – Secondary Distribution Service $0.5240 per kW
b. Rate DT – TOU Secondary Distribution Service $0.5240 per kW
c. Rate DP – Primary Distribution Service $0.5240 per kW
d. Rate TT – Transmission Service $0.4550 per kVA

Real Time Pricing – Market-Based Pricing – Rate RTP-M
(Electric Tariff Sheet No. 59)

Current Rate
Secondary Service $10.00 per month
Primary Service $100.00 per month
Transmission Service $500.00 per month
Energy Delivery Charge
Charge For Each KW Per Hour:
Secondary Service $0.010363 per kW per Hour
Primary Service $0.006462 per kW per Hour
Transmission Service $0.002433 per kW per Hour
Ancillary Services Charge shall be applied on an hour by hour basis.
Ancillary Services Charge for Each kW Per Hour:
Secondary Delivery $0.001002 per kW per Hour
Primary Delivery $0.000903 per kW per Hour
Transmission Delivery $0.000778 per kW per Hour

Proposed Rate
Secondary Service $15.00 per month
Primary Service $100.00 per month
Transmission Service $500.00 per month
Energy Delivery Charge
Charge For Each KW Per Hour:
Secondary Service $0.006074 per kW per Hour
Primary Service $0.005559 per kW per Hour
Transmission Service $0.002015 per kW per Hour
Ancillary Services Charge shall be applied on an hour by hour basis.
Ancillary Services Charge for Each kW Per Hour:
Secondary Delivery $0.000760 per kW per Hour
Primary Delivery $0.000740 per kW per Hour
Transmission Delivery $0.000721 per kW per Hour

Street Lighting Service – Rate SL
(Electric Tariff Sheet No. 60)

Current Rate
OVERHEAD DISTRIBUTION AREA

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$4.75
7,000 lumen (Open Refractor)	175	0.205	853	$3.66
10,000 lumen	250	0.275	1,144	$5.11
21,000 lumen	400	0.430	1,789	$6.40
Sodium Vapor				
9,500 lumen	100	0.117	487	$5.95
9,500 lumen (Open Refractor)	100	0.117	487	$4.25
16,000 lumen	150	0.171	711	$6.16
22,000 lumen	200	0.228	948	$7.97
50,000 lumen	400	0.471	1,959	$9.52
Decorative Fixtures				
Sodium Vapor				
9,500 lumen (Rectilinear)	100	0.117	487	$7.60
22,000 lumen (Rectilinear)	200	0.246	1,023	$8.67
50,000 lumen (Rectilinear)	400	0.471	1,959	$10.43
50,000 lumen (Setback)	400	0.471	1,959	$17.16

Where a street lighting fixture served overhead is to be installed on another utility's pole on which the Company does not have a contact, a monthly pole charge will be assessed.

Spans of Secondary Wiring:
For each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.45.

UNDERGROUND DISTRIBUTION AREA

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.210	874	$4.75
7,000 lumen (Open Refractor)	175	0.205	853	$3.66
10,000 lumen	250	0.292	1,215	$5.11
21,000 lumen	400	0.460	1,914	$6.40
Sodium Vapor				
9,500 lumen	100	0.117	487	$5.95
9,500 lumen (Open Refractor)	100	0.117	487	$4.25
16,000 lumen	150	0.171	711	$6.16
22,000 lumen	200	0.228	948	$7.97
50,000 lumen	400	0.471	1,959	$9.52
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$4.98
7,000 lumen (Holophane)	175	0.210	874	$6.61
7,000 lumen (Gas Replica)	175	0.210	874	$17.04
7,000 lumen (Aspen)	175	0.210	874	$10.25
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$8.59
9,500 lumen (Holophane)	100	0.128	532	$9.30
9,500 lumen (Rectilinear)	100	0.117	487	$7.60
9,500 lumen (Gas Replica)	100	0.128	532	$18.30
9,500 lumen (Aspen)	100	0.128	532	$10.91
22,000 lumen (Rectilinear)	200	0.246	1,023	$8.67
50,000 lumen (Rectilinear)	400	0.471	1,959	$10.43
50,000 lumen (Setback)	400	0.471	1,959	$17.16

POLE CHARGES

Pole Description	Pole Type	Rate/Pole
Wood		
17-foot (Wood Laminated) (a)	W17	$3.60
30-foot	W30	$3.75
35-foot	W35	$3.79
40-foot	W40	$4.55
Aluminum		
12-foot (decorative)	A12	$10.41
28-foot	A28	$6.00
28-foot (heavy duty)	A28H	$6.05
30-foot (anchor base)	A30	$11.96
Fiberglass		
17-foot	F17	$3.60
12-foot (decorative)	F12	$11.19
30-foot (bronze)	F30	$7.29
35-foot (bronze)	F35	$7.49
Steel		
27-foot (11 gauge)	S27	$9.84
27-foot (3 gauge)	S27H	$14.83

Spans of Secondary Wiring:
For each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.65.

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of 1.9091¢ per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

OVERHEAD DISTRIBUTION AREA

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$5.46
7,000 lumen (Open Refractor)	175	0.205	853	$4.21
10,000 lumen	250	0.275	1,144	$5.88
21,000 lumen	400	0.430	1,789	$7.36
Metal Halide				
14,000 lumen	175	0.193	803	$5.46
20,500 lumen	250	0.275	1,144	$5.88
36,000 lumen	400	0.430	1,789	$7.36
Sodium Vapor				
9,500 lumen	100	0.117	487	$6.84
9,500 lumen (Open Refractor)	100	0.117	487	$4.89
16,000 lumen	150	0.171	711	$7.08
22,000 lumen	200	0.228	948	$9.16
27,500 lumen	250	0.275	948	$9.16
50,000 lumen	400	0.471	1,959	$10.95
Decorative Fixtures				
Sodium Vapor				
9,500 lumen (Rectilinear)	100	0.117	487	$8.74
22,000 lumen (Rectilinear)	200	0.246	1,023	$9.97
50,000 lumen (Rectilinear)	400	0.471	1,959	$11.99
50,000 lumen (Setback)	400	0.471	1,959	$19.73

Where a street lighting fixture served overhead is to be installed on another utility's pole on which the Company does not have a contact, a monthly pole charge will be assessed.

Spans of Secondary Wiring:
For each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.52.

UNDERGROUND DISTRIBUTION AREA

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.210	874	$5.46
7,000 lumen (Open Refractor)	175	0.205	853	$4.21
10,000 lumen	250	0.292	1,215	$5.88
21,000 lumen	400	0.460	1,914	$7.36
Metal Halide				
14,000 lumen	175	0.210	874	$5.46
20,500 lumen	250	0.292	1,215	$5.88
36,000 lumen	400	0.460	1,914	$7.36
Sodium Vapor				
9,500 lumen	100	0.117	487	$6.84
9,500 lumen (Open Refractor)	100	0.117	487	$4.89
16,000 lumen	150	0.171	711	$7.08
22,000 lumen	200	0.228	948	$9.16
50,000 lumen	400	0.471	1,959	$10.95
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$5.73
7,000 lumen (Holophane)	175	0.210	874	$7.60
7,000 lumen (Gas Replica)	175	0.210	874	$19.59
7,000 lumen (Granville)	175	0.205	853	$5.73
7,000 lumen (Aspen)	175	0.210	874	$11.78
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$5.73
14,000 lumen (Granville Acorn)	175	0.210	874	$11.78
14,000 lumen (Gas Replica)	175	0.210	874	$19.59
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$9.88
9,500 lumen (Holophane)	100	0.128	532	$10.69
9,500 lumen (Rectilinear)	100	0.117	487	$8.74
9,500 lumen (Gas Replica)	100	0.128	532	$21.04
9,500 lumen (Aspen)	100	0.128	532	$12.54
9,500 lumen (Traditionaire)	100	0.117	487	$9.88
9,500 lumen (Granville Acorn)	100	0.128	532	$12.54
22,000 lumen (Rectilinear)	200	0.246	1,023	$9.97
50,000 lumen (Rectilinear)	400	0.471	1,959	$11.99
50,000 lumen (Setback)	400	0.471	1,959	$19.73

POLE CHARGES

Pole Description	Pole Type	Rate/Pole
Wood		
17-foot (Wood Laminated) (a)	W17	$4.37
30-foot	W30	$4.31
35-foot	W35	$4.36
40-foot	W40	$5.23
Aluminum		
12-foot (decorative)	A12	$11.97
28-foot	A28	$5.89
28-foot (heavy duty)	A28H	$6.96
30-foot (anchor base)	A30	$13.76
Fiberglass		
17-foot	F17	$4.37
12-foot (decorative)	F12	$12.87
30-foot (bronze)	F30	$8.38
35-foot (bronze)	F35	$8.60

Steel		
27-foot (11 gauge)	S27	$11.31
27-foot (3 gauge)	S27H	$17.05

Spans of Secondary Wiring:
For each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.75

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of $0.021619 per kilowatt-hour reflecting the base cost of fuel.

Traffic Lighting Service – Rate TL
(Electric Tariff Sheet No. 61)

Current Rate
Where the Company supplies energy only, all kilowatt-hours shall be billed at 3.09 cents per kilowatt hour.
Where the Company supplies energy from a separately metered source and the Company has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 1.80 cents per kilowatt-hour.
Where the Company supplies energy and has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 4.89 cents per kilowatt-hour.

Proposed Rate
Where the Company supplies energy only, all kilowatt-hours shall be billed at $0.035196 per kilowatt-hour.
Where the Company supplies energy from a separately metered source and the Company has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at $0.020695 per kilowatt-hour.
Where the Company supplies energy and has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at $0.055892 per kilowatt-hour.

Unmetered Outdoor Lighting Electric Service – Rate UOLS
(Electric Tariff Sheet No. 62)

Current Rate
All KWh 3.04¢ per KWh

Proposed Rate
All KWh $0.034521 per KWh

Outdoor Lighting Service – Rate OL
(Electric Tariff Sheet No. 65)

Current Rate

Private Outdoor Lighting Units	Lamp Watts	kW/ Luminaire	Annual kWh	Rate/Unit
Standard Fixtures (Cobra Head)				
Mercury Vapor				
7,000 lumen (Open Refractor)	175	0.205	853	$5.98
7,000 lumen	175	0.210	874	$8.04
10,000 lumen	250	0.292	1,215	$9.04
21,000 lumen	400	0.460	1,914	$10.99
Sodium Vapor				
9,500 lumen (Open Refractor)	100	0.117	487	$5.71
9,500 lumen	100	0.117	487	$7.70
16,000 lumen	150	0.171	711	$8.40
22,000 lumen	200	0.228	948	$9.01
50,000 lumen	400	0.471	1,959	$9.03
Decorative Fixtures (a)				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$9.96
7,000 lumen (Holophane)	175	0.210	874	$13.22
7,000 lumen (Gas Replica)	175	0.210	874	$34.08
7,000 lumen (Aspen)	175	0.210	874	$20.50
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$17.18
9,500 lumen (Holophane)	100	0.128	532	$18.60
9,500 lumen (Rectilinear)	100	0.117	487	$15.20
9,500 lumen (Gas Replica)	100	0.128	532	$36.60
9,500 lumen (Aspen)	100	0.128	532	$21.82
22,000 lumen (Rectilinear)	200	0.246	1,023	$17.34
50,000 lumen (Rectilinear)	400	0.471	1,959	$20.86
50,000 lumen (Setback)	400	0.471	1,959	$34.32
A. Flood lighting units served in overhead distribution areas (FL):				
Mercury Vapor				
21,000 lumen	400	0.460	1,914	$11.00
Sodium Vapor				
22,000 lumen	200	0.246	1,023	$8.81
50,000 lumen	400	0.480	1,997	$9.66

Base Fuel Cost:
All kWh shall be subject to a charge of 1.9091 cents per kWh reflecting the base cost of fuel.

Proposed Rate

Private Outdoor Lighting Units	Lamp Watts	kW/ Luminaire	Annual kWh	Rate/Unit
Standard Fixtures (Cobra Head)				
Mercury Vapor				
7,000 lumen (Open Refractor)	175	0.205	853	$6.66
7,000 lumen	175	0.210	874	$9.24
10,000 lumen	250	0.292	1,215	$10.39
21,000 lumen	400	0.460	1,914	$12.64
Metal Halide				
14,000 lumen	175	0.210	874	$9.24
20,500 lumen	250	0.307	1,215	$10.39
36,000 lumen	400	0.460	1,914	$12.64
Sodium Vapor				
9,500 lumen (Open Refractor)	100	0.117	487	$6.57
9,500 lumen	100	0.117	487	$8.85
16,000 lumen	150	0.171	711	$9.66
22,000 lumen	200	0.228	948	$10.36
27,500 lumen	250	0.228	948	$10.36
50,000 lumen	400	0.471	1,959	$10.38
Decorative Fixtures (a)				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$11.45
7,000 lumen (Holophane)	175	0.210	874	$15.20
7,000 lumen (Gas Replica)	175	0.210	874	$39.18
7,000 lumen (Aspen)	175	0.210	874	$23.57
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$11.45
14,000 lumen (Granville Acorn)	175	0.210	874	$23.57
14,000 lumen (Gas Replica)	175	0.210	874	$39.18
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$19.75
9,500 lumen (Holophane)	100	0.128	532	$21.39
9,500 lumen (Rectilinear)	100	0.117	487	$17.46
9,500 lumen (Gas Replica)	100	0.128	532	$42.08
9,500 lumen (Aspen)	100	0.128	532	$25.09
9,500 lumen (Traditionaire)	100	0.117	487	$19.75
9,500 lumen (Granville Acorn)	100	0.128	532	$25.09
22,000 lumen (Rectilinear)	200	0.246	1,023	$19.94
50,000 lumen (Rectilinear)	400	0.471	1,959	$23.98
50,000 lumen (Setback)	400	0.471	1,959	$39.46
A. Flood lighting units served in overhead distribution areas (FL):				
Mercury Vapor				
21,000 lumen	400	0.460	1,914	$12.65
Metal Halide				
20,500 lumen	250	0.307	1,215	$10.39
36,000 lumen	400	0.460	1,914	$12.65
Sodium Vapor				
22,000 lumen	200	0.246	1,023	$10.13
30,000 lumen	250	0.312	1,023	$10.13
50,000 lumen	400	0.480	1,997	$11.11

Base Fuel Cost:
All kWh shall be subject to a charge of $0.021619 per kWh reflecting the base cost of fuel.

Street Lighting Service for Non-Standard Units – Rate NSU
(Electric Tariff Sheet No. 66)

Current Rate

Company-Owned Units	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Boulevard units served underground				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$6.82
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$4.75
Holophane Decorative fixture on 17-foot fiberglass pole served underground with direct buried cable				
a. 10,000 lumen Mercury Vapor	250	0.292	1,215	$12.24

The cable span charge of $.65 per each increment of 25 feet of secondary wiring shall be added to the Rate/unit charge for each increment of secondary wiring beyond the first 25 feet from the pole base.

	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Street light units served overhead distribution				
a. 2,500 lumen Incandescent	189	0.189	786	$4.70
b. 2,500 lumen Mercury Vapor	100	0.109	453	$4.95
c. 21,000 lumen Mercury Vapor	400	0.460	1,914	$5.79
Customer owned				
Steel boulevard units served underground with limited maintenance by Company				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$3.58
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$4.55

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of 1.9091¢ per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

Company owned	Lamp Watts	KW/Unit	Annual kWh	Rate/Unit
Boulevard units served underground				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$7.84
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$5.46
Holophane Decorative fixture on 17-foot fiberglass pole served underground with direct buried cable				
a. 10,000 lumen Mercury Vapor	250	0.292	1,215	$14.07

The cable span charge of $.75 per each increment of 25 feet of secondary wiring shall be added to the Rate/unit charge for each increment of secondary wiring beyond the first 25 feet from the pole base.

	Lamp Watts	KW/Unit	Annual kWh	Rate/Unit
Street light units served overhead distribution				
a. 2,500 lumen Incandescent	189	0.189	786	$5.40
b. 2,500 lumen Mercury Vapor	100	0.109	453	$5.69
c. 21,000 lumen Mercury Vapor	400	0.460	1,914	$6.63
Customer owned				
Steel boulevard units served underground with limited maintenance by Company				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$4.12
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$5.23

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of $0.021619 per kilowatt-hour reflecting the base cost of fuel.

Private Outdoor Lighting for Non-Standard Units – Rate NSP
(Electric Tariff Sheet No. 67)

Current Rate
A. Private outdoor lighting units:
The following monthly charge will be assessed for existing facilities, but this unit will not be available to any new customers after May 15, 1973:

	Lamp Watts	KW/ Unit	Annual KWh	Rate/Unit
2,500 lumen Mercury, Open Refractor	100	0.115	478	$5.84
2,500 lumen Mercury, Enclosed Refractor	100	0.115	478	$8.29

B. Outdoor lighting units served in underground residential distribution areas:
The following monthly charge will be assessed for existing fixtures which include lamp and luminaire, controlled automatically, with an underground service wire not to exceed 35 feet from the service point, but these units will not be available to new customers after May 5, 1992:

	Lamp Watts	KW/ Unit	Annual KWh	Rate/Unit
7,000 lumens Mercury, Mounted on a 17-foot Fiberglass Pole.	175	0.205	853	$10.95
7,000 lumen Mercury, Mounted on a 17-foot Wood Laminated Pole (a)	175	0.205	853	$10.95
7,000 lumen Mercury, Mounted on a 30-foot Wood Pole	175	0.205	853	$10.01
9,500 lumen Sodium Vapor, TC 100 R	100	0.117	487	$8.73

(a) Note: New or replacement poles are not available.

C. Flood lighting units served in overhead distribution areas:
The following monthly charge will be assessed for each existing fixture, which includes lamp and luminaire, controlled automatically, mounted on a utility pole, as specified by the Company, with a span of wire not to exceed 120 feet, but these units will not be available after May 5, 1992:

	Lamp Watts	KW/ Fixture	Annual KWh	Rate/Unit
52,000 lumen Mercury (35-foot Wood Pole)	1,000	1.102	4,584	$16.47
52,000 lumen Mercury (50-foot Wood Pole)	1,000	1.102	4,584	$19.55
50,000 lumen Sodium Vapor	400	0.471	1,959	$13.53

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of 1.9091¢ per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate
A. Private outdoor lighting units:
The following monthly charge will be assessed for existing facilities, but this unit will not be available to any new customers after May 15, 1973:

	Lamp Watts	KW/ Unit	Annual kWh	Rate/Unit
2,500 lumen Mercury, Open Refractor	100	0.115	478	$6.71
2,500 lumen Mercury, Enclosed Refractor	100	0.115	478	$9.53

B. Outdoor lighting units served in underground residential distribution areas:
The following monthly charge will be assessed for existing fixtures which include lamp and luminaire, controlled automatically, with an underground service wire not to exceed 35 feet from the service point, but these units will not be available to new customers after May 5, 1992:

	Lamp Watts	KW/ Unit	Annual kWh	Rate/Unit
7,000 lumen Mercury, Mounted on a 17-foot Fiberglass Pole	175	0.205	853	$12.59
7,000 lumen Mercury, Mounted on a 17-foot Wood Laminated Pole (a)	175	0.205	853	$12.59
7,000 lumen Mercury, Mounted on a 30-foot Wood Pole	175	0.205	853	$11.51
9,500 lumen Sodium Vapor, TC 100 R	100	0.117	487	$10.04

(a) Note: New or replacement poles are not available.

C. Flood lighting units served in overhead distribution areas:
The following monthly charge will be assessed for each existing fixture, which includes lamp and luminaire, controlled automatically, mounted on a utility pole, as specified by the Company, with a span of wire not to exceed 120 feet, but these units will not be available after May 5, 1992:

	Lamp Watts	KW/ Fixture	Annual KWh	Rate/Unit
52,000 lumen Mercury (35-foot Wood Pole)	1,000	1.102	4,584	$18.94
52,000 lumen Mercury (50-foot Wood Pole)	1,000	1.102	4,584	$22.48
50,000 lumen Sodium Vapor	400	0.471	1,959	$15.56

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of $0.021619 per kilowatt-hour reflecting the base cost of fuel.

Street Lighting Service-Customer Owned – Rate SC
(Electric Tariff Sheet No. 68)

Current Rate

Fixture Description	Lamp Watts	KW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$2.25
10,000 lumen	250	0.275	1,144	$2.66
21,000 lumen	400	0.430	1,789	$3.35
Sodium Vapor				
9,500 lumen	100	0.117	487	$3.40
16,000 lumen	150	0.171	711	$3.66
22,000 lumen	200	0.228	948	$3.72
50,000 lumen	400	0.471	1,959	$3.89
Decorative Fixture				
Mercury Vapor				
7,000 lumen (Holophane)	175	0.210	874	$3.12
7,000 lumen (Town & Country)	175	0.205	853	$3.11
7,000 lumen (Gas Light Replica)	175	0.210	874	$3.12
7,000 lumen (Aspen)	175	0.210	874	$3.12
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$3.47
9,500 lumen (Rectilinear)	100	0.117	487	$3.47
9,500 lumen (Aspen)	100	0.128	532	$3.58
9,500 lumen (Holophane)	100	0.128	532	$3.58
9,500 lumen (Gas Light Replica)	100	0.128	532	$3.58
22,000 lumen (Rectilinear)	200	0.246	1,023	$3.92
50,000 lumen (Rectilinear)	400	0.471	1,959	$4.14

Where a street lighting fixture served overhead is to be installed on another utility's pole on which the Company Does not have a contact, a monthly pole charge will be assessed.

Pole Description	Pole Type	Rate/Pole
Wood		
30-foot	W30	$3.75
35-foot	W35	$3.79
40-foot	W40	$4.54

Customer Owned and Maintained Units
All KWh shall be billed at 3.04¢ per KWh plus applicable riders.

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of 1.9091¢ per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$2.59
10,000 lumen	250	0.275	1,144	$3.06
21,000 lumen	400	0.430	1,789	$3.65
Metal Halide				
14,000 lumen	175	0.193	803	$2.59
20,500 lumen	250	0.275	1,144	$3.06
36,000 lumen	400	0.430	1,789	$3.65
Sodium Vapor				
9,500 lumen	100	0.117	487	$3.98
16,000 lumen	150	0.171	711	$4.21
22,000 lumen	200	0.228	948	$4.28
27,500 lumen	250	0.228	948	$4.28
50,000 lumen	400	0.471	1,959	$4.47
Decorative Fixture				
Mercury Vapor				
7,000 lumen (Holophane)	175	0.210	874	$3.59
7,000 lumen (Town & Country)	175	0.205	853	$3.58
7,000 lumen (Gas Replica)	175	0.210	874	$3.59
7,000 lumen (Aspen)	175	0.210	874	$3.59
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$3.58
14,000 lumen (Granville Acorn)	175	0.210	874	$3.59
14,000 lumen (Gas Replica)	175	0.210	874	$3.59
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$3.99
9,500 lumen (Traditionaire)	100	0.117	487	$3.99
9,500 lumen (Granville Acorn)	100	0.128	532	$4.12
9,500 lumen (Rectilinear)	100	0.117	487	$3.99
9,500 lumen (Aspen)	100	0.128	532	$4.12
9,500 lumen (Holophane)	100	0.128	532	$4.12
9,500 lumen (Gas Replica)	100	0.128	532	$4.12
22,000 lumen (Rectilinear)	200	0.246	1,023	$4.51
50,000 lumen (Rectilinear)	400	0.471	1,959	$4.76

Pole Description	Pole Type	Rate/Pole
Wood		
30-foot	W30	$4.31
35-foot	W35	$4.36
40-foot	W40	$5.23

Customer Owned and Maintained Units
All KWh shall be billed at $0.034521 per kWh plus applicable riders.

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of $0.021619 per kilowatt-hour reflecting the base cost of fuel.

Street-lighting Service-Overhead Equivalent – Rate SE
(Electric Tariff Sheet No. 69)

Current Rate

Fixture Description	Lamp Watts	kW/Unit	Annual KWh	Rate/Unit
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$4.75
7,000 lumen (Holophane)	175	0.210	874	$4.75
7,000 lumen (Gas Replica)	175	0.210	874	$4.75
7,000 lumen (Aspen)	175	0.210	874	$4.75
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$5.95
9,500 lumen (Holophane)	100	0.128	532	$5.95
9,500 lumen (Rectilinear)	100	0.117	487	$5.95
9,500 lumen (Gas Replica)	100	0.128	532	$5.95
9,500 lumen (Aspen)	100	0.128	532	$5.95
22,000 lumen (Rectilinear)	200	0.246	1,023	$7.97
50,000 lumen (Rectilinear)	400	0.471	1,959	$9.52
50,000 lumen (Setback)	400	0.471	1,959	$9.52

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of 1.9091¢ per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

Fixture Description	Lamp Watts	KW/Unit	Annual KWh	Rate/Unit
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$5.46
7,000 lumen (Holophane)	175	0.210	874	$5.46
7,000 lumen (Gas Replica)	175	0.210	874	$5.46
7,000 lumen (Aspen)	175	0.210	874	$5.46
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$5.46
14,000 lumen (Granville Acorn)	175	0.210	874	$5.46
14,000 lumen (Gas Replica)	175	0.210	874	$5.46
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$6.84
9,500 lumen (Holophane)	100	0.128	532	$6.84
9,500 lumen (Rectilinear)	100	0.117	487	$6.84
9,500 lumen (Gas Replica)	100	0.128	532	$6.84
9,500 lumen (Aspen)	100	0.128	532	$6.84
9,500 lumen (Traditionaire)	100	0.117	487	$6.84
9,500 lumen (Granville Acorn)	100	0.128	532	$6.84
22,000 lumen (Rectilinear)	200	0.246	1,023	$9.16
50,000 lumen (Rectilinear)	400	0.471	1,959	$10.95
50,000 lumen (Setback)	400	0.471	1,959	$10.95

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of $0.021619 per kilowatt-hour reflecting the base cost of fuel.

Transmission Cost Recovery Mechanism – Rider TCRM
(Electric Tariff Sheet No. 83)

Current Rate This rider is currently not available.

Proposed Rate
Applicability
Applicable to all jurisdictional retail customers in the Company's electric service area.
Whenever the average cost of transmission charged to the Company by its Regional Transmission Organization is greater or less than the average cost of this transmission included per kilowatt-hour of sales in the base period, there shall be added to or subtracted from the net monthly bill to which this Rider is applicable, an amount determined by multiplying the number of kilowatt-hours consumed by the customer for which the bill is rendered by a Rider TCRM adjustment.

1. The charge per kilowatt-hour delivered under the rate schedule to which this adjustment is applicable shall be increased or decreased during each year in accordance with the following formula:

$$\text{Adjustment Factor} = \frac{T(y)}{S(y)} - \frac{T(b)}{S(b)}$$

Where:
a. "T" is the transmission related Midwest ISO costs billed to Duke Energy Kentucky.
b. "S" is the kilowatt-hour sales.
c. "y" is the current year.
d. "b" is the base year.

Backup Delivery Point Capacity Rider – Rider BDP
(Electric Tariff Sheet No. 84)

Current Rate This rider is currently not available.

Proposed Rate
Backup Delivery Point Capacity Rider
The Company will normally supply service to one premises at one standard voltage at one delivery point and through one meter to a Non-Residential Customer in accordance with the provisions of the applicable rate schedule and the Electric Service Regulations. Upon customer request, Company will make available to a Non-Residential Customer additional delivery points in accordance with the rates, terms and conditions of this Rider BDP.

Net Monthly Bill
1. Connection Fee: The Connection Fee applies only if an additional metering point is required.
2. Monthly charges will be based on the unbundled distribution and/or transmission rates of the customer's most applicable rate schedule and the contracted for reserve backup delivery point capacity.
3. The Customer shall also be responsible for the acceleration of costs, if any, that would not have otherwise been incurred by Company

absent such request for additional delivery points. The terms of payment may be made initially or over a pre-determined term mutually agreeable to Company and Customers that shall not exceed the minimum term. In each request for service under this Rider, Company engineers will conduct a thorough review of the customer's request and the circuits affected by the request. The customer's capacity needs will be weighed against the capacity available on the circuit, anticipated load growth on the circuit, and any future construction plans that may be advanced by the request.

Green Power Rider – Rider GP
(Electric Tariff Sheet No. 88)

Current Rate

Applicability

Applicable to all customers who want to contribute to a Company-sponsored "Green Power" fund. The term of this pilot program is three (3) years.

Definition of Green Power

Green Power includes energy generated from environmentally friendly sources, including, but not limited to: hydroelectric generation, photovoltaic generation, solar thermal generation, wind generation, biomass generation, and methane recovery.

Net Monthly Bill

Customers who participate in this Rider will be billed for electric service under all standard applicable tariffs and riders. The customer's contribution to the Green Power fund will be added to the customer's bill for electric service.

Proposed Rate

Applicability

Applicable to all customers who wish to purchase "Green Power" from the Company-sponsored "Green Power" program. This rider will be available until December 31, 2008.

Definition of Green Power

Green Power includes energy generated from renewable and/or environmentally friendly sources, including: Wind, Solar Photovoltaic, Biomass Co-firing of Agricultural Crops and All energy crops, Hydro – as certified by the Low Impact Hydro Institute, Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-firing of All Woody Waste including mill residue, but excluding painted or treated lumber.

Green Power includes the purchase of Renewable Energy Certificates and/or Carbon Credits from the sources described above.

Green Power Rate

1. Rate RS
   For all Green Power kWh, including carbon credits, purchased per month $0.025 per kWh. Minimum purchase is 200 kWh. Additional purchases to be made in 100 kWh block increments.
2. All other rates
   Individually calculated Green Power Rate per service agreement which may also include carbon credits.

Net Metering Rider – Rider NM
(Electric Tariff Sheet No. 89)

Current Rate

Availability

Net Metering is provided upon request and on a first-come, first-served basis. Net Metering is available to customers with a capacity of 15 kW or less. The total nameplate rating of all customer-generators under net metering is limited to one-percent (1%) of the Company's total peak system load.

Proposed Rate

Availability

Net Metering is provided upon request and on a first-come, first-served basis. Net Metering is available to customers with a capacity of 15 kW or less. At its sole discretion, Company may provide Net Metering to other customers on a case-by-case basis. The total nameplate rating of all customer-generators under net metering is limited to one-percent (1%) of the Company's total peak system load.

Charge for Reconnection of Service
(Electric Tariff Sheet No. 91)

Current Rate

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be twenty-five dollars ($25.00).
B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be twenty-five dollars ($25.00).
C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of twenty-five dollars ($25.00) the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for electricity used, prior to the reconnection of service.
D. If both the gas and electric services are reconnected at one time, the total charge shall not exceed thirty-eight dollars ($38.00).

Proposed Rate

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be twenty-five dollars ($25.00).
B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be twenty-five dollars ($25.00).
C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of twenty-five dollars ($25.00) the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for electricity used, prior to the reconnection of service.
D. If both the gas and electric services are reconnected at one time, the total charge shall not exceed thirty-eight dollars ($38.00).
E. Where electric service was disconnected at the pole because the Company was unable to gain access to the meter, the reconnection charge shall be sixty-five dollars ($65.00). If the gas service is also reconnected the charge shall be ninety dollars ($90.00).
F. If the Company receives notice after 12:30 p.m. of a customer's desire for same day reinstatement of service and if the service cannot be performed during normal business hours, the after hours reconnection charge for connection at the meter shall be fifty dollars ($50.00). The after hours charge for reconnection at the pole shall be ninety dollars ($90.00).
G. If a Company employee, whose original purpose was to disconnect the service, has provided the customer a means to avoid disconnection, service which otherwise would have been disconnected shall remain intact, and no reconnection charge shall be assessed. However, a collection charge of fifteen dollars ($15.00) may be assessed.

Cogeneration and Small Power Production Sale and Purchase Tariff – 100 kW or Less
(Electric Tariff Sheet No. 93)

Current Rate

Rates for Purchases from qualifying facilities:

Purchase Rate shall be 1.95¢/kWh for all kilowatt-hours delivered.

Proposed Rate

Rates for Purchases from qualifying facilities:

Purchase Rate shall be $0.03078/kWh for all kilowatt-hours delivered.

Cogeneration and Small Power Production Sale and Purchase Tariff – Greater Than 100 kW
(Electric Tariff Sheet No. 94)

Current Rates

Rate Schedules

Rates for Purchase from qualifying facilities:

The Purchase Rate for all kilowatt-hours delivered shall be determined according to the standard calculation of avoided costs as set forth herein.

Rates for Sales to qualifying facilities will be accomplished through existing tariff schedules on file with the Ky. PSC.

Calculation of Avoided Cost

The methodology to determine avoided cost involves the use of the Electric Generation Expansion Analysis System, (EGEAS) to develop differential long run marginal costs between Duke Energy Ohio/Duke Energy Kentucky's optimum base case generation expansion plan and an optimum expansion plan including the QF. The key feature of the methodology is the complete reoptimization of the base case generation expansion plan including capital costs, fuel cost, and operation and maintenance expenses to insure that the ratepayer will remain indifferent toward the capacity and energy cost of any cogenerator or small power producer.

Sample Rates:

Cogen/Spp Contract Length	Capacity Component	Weighted Energy Component	Total Cogen/Spp Credit (¢/kWhAllHours)
5 Yr	0.81¢/kWh	1.95¢/kWh	2.76¢/kWh
10 Yr.	1.16¢/kWh	1.95¢/kWh	3.11¢/kWh
15 Yr.	1.63¢/kWh	1.95¢/kWh	3.58¢/kWh
20 Yr	2.92¢/kWh	1.95¢/kWh	4.87¢/kWh

Proposed Rates:

Rate Schedules

Rates for Purchase from qualifying facilities:

The Purchase Rate for all kilowatt-hours delivered shall be the locational marginal price for power purchased through the Midwest ISO day-ahead energy market, inclusive of the energy, congestion and losses charges, delivered to the Duke Energy Kentucky commercial price node.

Rates for Sales to qualifying facilities will be accomplished through *existing tariff schedules on file with the Kentucky PSC.*

Real Time Pricing Program – Rate RTP
(Electric Tariff Sheet No. 99)

Current Rate

ENERGY DELIVERY CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Service	$0.004800 per kW Per Hour
Primary Service	$0.004600 per kW Per Hour
Transmission Service	$0.001600 per kW Per Hour

ANCILLARY SERVICES CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Delivery	$0.000760 per kW Per Hour
Primary Delivery	$0.000740 per kW Per Hour
Transmission Delivery	$0.000721 per kW Per Hour

DSMR CHARGE

All kWh, adjusted to reflect required metering adjustments under this rate schedule, shall be subject to application of the amount per kWh stated on Sheet No. 78, Rider DSMR, Demand Side Management Rate (DSMR)

PROGRAM CHARGE

Company will provide Internet based communication software to be used to provide Customer with the Price Quotes. Customer will be responsible for providing its own Internet access. A charge of $150.00 per billing period per site shall be added to Customer's bill to cover the additional billing, administrative, and cost of communicating the hourly Price Quotes associated with the RTP Program.

SPECIAL TERMS AND CONDITIONS

Except as provided in this Rate RTP, all terms, conditions, rates and charges outlined in the Standard Rate Schedule will apply. Participation in the RTP Program will not affect Customer's obligations for electric service under the Standard Rate Schedule.

Customers receiving service under Rider IS or a special contract that contains an interruptible service provision will be unable to participate in the RTP Program. Adjustments will be made to the CBL to reflect the interruptible service.

Customers who terminate their service agreement under this Rider RTP after the initial one (1) year term shall be ineligible to return to the program for twelve (12) months from the termination date.

The primary term of service is one (1) year consisting of a consecutive twelve month period.

Customers returning to the standard tariff shall have any historical demands in excess of the CBL, waived for purposes of calculating applicable billing demands.

The supplying and billing for service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's Service Regulations currently in effect, as filed with the Kentucky Public Service Commission.

Proposed Rate

ENERGY DELIVERY CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Service	$0.006074 per kW Per Hour
Primary Service	$0.005559 per kW Per Hour
Transmission Service	$0.002015 per kW Per Hour

ANCILLARY SERVICES CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Delivery	$0.000760 per kW Per Hour
Primary Delivery	$0.000740 per kW Per Hour
Transmission Delivery	$0.000721 per kW Per Hour

PROGRAM CHARGE

Company will provide Internet based communication software to be used to provide Customer with the Price Quotes. Customer will be responsible for providing its own Internet access. A charge of $150.00 per billing period per site shall be added to Customer's bill to cover the additional billing, administrative, and cost of communicating the hourly Price Quotes associated with the RTP Program.

SPECIAL TERMS AND CONDITIONS

Except as provided in this Rate RTP, all terms, conditions, rates and charges outlined in the Standard Rate Schedule will apply. Participation in the RTP Program will not affect Customer's obligations for electric service under the Standard Rate Schedule.

Customers who terminate their service agreement under this Rider RTP after the initial one (1) year term shall be ineligible to return to the program for twelve (12) months from the termination date.

The primary term of service is one (1) year consisting of a consecutive twelve month period.

Customers returning to the standard tariff shall have any historical demands in excess of the CBL, waived for purposes of calculating applicable billing demands.

The supplying and billing for service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's Service Regulations currently in effect, as filed with the Kentucky Public Service Commission.

Fuel Cost Adjustment – Rider F
(Electric Tariff Sheet No. 80)

Current Rate

It has been determined that the base period fuel cost [F(b)/S(b)] as of *August 1, 1983 is 1.9091 cents per kilowatt-hour.*

Notwithstanding the above Fuel Cost Adjustment provisions, the company's FAC rate shall be fixed at (0.2525) cents per kilowatt-hour effective with Billing Cycle 1, June 2001.

Proposed Rate (now titled Rider FAC)

Fuel Adjustment Calculation

1. The monthly amount computed under each of the rate schedules to which this fuel clause is applicable shall be increased or (decreased) at a rate per kilowatt-hour of monthly consumption in accordance with the following formula:

$$\text{Fuel Cost Adjustment} = \frac{F(m)}{S(m)} - \$0.021619$$

   Where F is the expense of fuel in the second preceding month and S is the sales in the second preceding month, as defined below.

2. Fuel costs (F) shall be the cost of:
   A. Fossil fuel consumed in the Company's plants plus the cost of fuel which would have been used in Plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, plus
   B. *The actual identifiable fossil and nuclear fuel costs associated with* energy purchased for reasons other than identified in paragraph (c) of this subsection, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus
   C. The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to each transaction) when such energy is purchased on an economic dispatch basis. Included therein are such costs as the charges for economy energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy, and; less
   D. The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic basis.
   E. All fuel costs shall be based on a weighted-average inventory costing. The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of fuel itself and necessary charges for transportation of fuel from the point of acquisition to the unloading point, as listed in Account 151 of the FERC Uniform System of Accounts for Public Utilities and Licensees.
   F. As used herein, the term "forced outages" means all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection, or acts of the public enemy, then the Company may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment.
3. Sales (S) shall be determined in kilowatt-hours as follows:
   Add:
   A. net generation
   B. purchases
   C. interchange in
   Subtract:
   D. inter-system sales including economy energy and other energy sold on an economic dispatch basis.
   E. total system losses

Duke Energy Kentucky proposes the following new tariff schedules: Rider BDP, Backup Delivery Point Capacity Rider; and, Rider TCRM, Transmission Cost Recovery Mechanism. The following tariff schedules are proposed to be eliminated: Sheet No. 70, Rider SES, Standby or Emergency Service; Sheet No. 74, Rider IS, Interruptible Service Rider; Sheet No. 76, Rider TES, Thermal Energy Storage Rider; and, Sheet No. 79, Rider EOP-RTP, Energy Call Option Program.

In addition, Duke Energy Kentucky proposes to change the text of the following tariff schedules: Sheet No. 20, Service Regulations, Section I - Service Agreement; Sheet No. 23, Service Regulations, Section IV – Company's Installation; Sheet No. 77, Rider PLM, Peak Load Management Rider.

The foregoing rates reflect a proposed increase in electric revenues of approximately $56.6 million or 27.6% over current total electric revenues to Duke Energy Kentucky. The estimated amount of this increase per rate class is shown below. The average monthly bill for each rate class to which the proposed rate will apply are also shown in the table below:

Tariff Description	Revenue Increase Dollars ($)	Revenue Increase Percent (%)	Average Bill Increase Dollars ($)	Average Bill Increase Percent (%)
Rate RS, Residential Service	32,634,829	33.42	19.48	30.0
Total Residential Customer Class	32,634,829	33.42	19.48	30.0
Rate DS, Distribution Voltage Service	15,712,565	23.60	142.64	23.0
Rate DT, TOD Rate for Distribution Voltage – Prim.	5,298,878	26.68	5,968.93	28.0
Rate DT, TOD Rate for Distribution Voltage – Sec.	10,176,341	26.52	5,968.93	28.0
Rate EH, Optional Electric Space Heating Rate	259,701	37.39	176.53	38.4
Rate SP, Seasonal Sports Service	4,971	14.16	15.17	13.9
Rate GS-FL, Small Fixed Load Rate	36,174	7.67	3.51	7.4
Rate DP, Primary Voltage Service	498,707	28.26	3,834.44	27.2
Total Distribution Customer Class	31,987,337	25.03	10,141.22	27.7
Rate TT, Transmission Voltage Service	1,465,160	17.17	9,622.00	16.2
Total Transmission Customer Class	1,465,160	17.17	9,622.00	16.2
Rate DT-RTP-Prim. – Real Time Pricing	19,840	2.49	71.22	3.4
Rate DT-RTP-Sec. – Real Time Pricing	11,067	3.22	253.95	2.8
Rate DS-RTP – Real Time Pricing	2,468	3.52	147.66	3.8
Rate TT-RTP – Real Time Pricing	5,565	1.38	5,013.00	1.2
Total Real Time Pricing Customer Class	38,570	2.41	5,485.83	1.3
Rate SL, Street Lighting Service	203,869	17.51	1.43	17.5
Rider TL, Traffic Lighting Service	54,767	20.90	0.62	20.9
Rider UOLS, Unmetered Outdoor Lighting Service	88	24.31	0.80	24.3
Rider OL, Outdoor Lighting Service	91,749	17.59	1.77	17.6
Rider NSU, Street Lighting – Non-Standard Units	9,229	17.17	1.06	17.2
Rider NSP, Outdoor Lighting – Non-Standard Units	7,437	16.63	1.43	16.6
Rate SC, Street Lighting – Customer-Owned	760	24.00	0.35	24.0
Rate SE, Street Lighting – Overhead Equivalent	25,052	17.39	1.10	17.4
Total Lighting Customer Class	392,971	17.91	1.22	17.9

The rates contained in this notice are the rates proposed by Duke Energy Kentucky; however, the Kentucky Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. Such action may result in rates for consumers other than the rates in this notice.

Any corporation, association, body politic or person with a substantial interest in the matter may, by written request within thirty (30) days after *publication of this notice of the proposed rate changes, request leave to* intervene; intervention may be granted beyond the thirty (30) day period for good cause shown. Such motion shall be submitted to the Kentucky Public Service Commission, P. O. Box 615, 211 Sower Boulevard, Frankfort, Kentucky 40602-0615, and shall set forth the grounds for the request including the status and interest of the party.

Intervenors may obtain copies of the application and other filings made by the Company by contacting Ms. Anita Schafer of Duke Energy Kentucky at the address specified below or by telephone at (513) 287-3842. A copy of the application and other filings made by the Company is available for public inspection at the Commission's office in Frankfort, Kentucky, and at the following Company offices: 1697 A Monmouth Street, Newport, KY 41071.

For further information contact:

PUBLIC SERVICE COMMISSION
COMMONWEALTH OF KENTUCKY
P. O. BOX 615
211 SOWER BOULEVARD
FRANKFORT, KENTUCKY 40602-0615
(502) 564-3940

DUKE ENERGY KENTUCKY
1697 A MONMOUTH STREET
NEWPORT, KENTUCKY 41071
(513) 287-3842

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(2)

---

807 KAR 5:001, SECTION 10(2)

Description of Filing Requirement:

Notice of intent. Utilities with gross annual revenues greater than $1,000,000 shall file with the commission a written notice of intent to file a rate application at least four (4) weeks prior to filing their application. The notice of intent shall state whether the rate application will be supported by a historical test period or a fully forecasted test period. This notice shall be served upon the Attorney General, Utility Intervention and Rate Division.

Response:

See attached.

Sponsoring Witness: Sandra P. Meyer

Duke Energy®

SANDRA P. MEYER
President

Duke Energy Ohio
Duke Energy Kentucky
139 East Fourth Street
Cincinnati, OH 45202

513 419 5499
513 419 5470 fax
513 706 1065 cell
spmeyer@duke-energy.com

RECEIVED
APR 27 2006
PUBLIC SERVICE COMMISSION

VIA OVERNIGHT MAIL

April 26, 2006

Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: Notice of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky's Intent to File a General Electric Rate Case Case No. 2006-00172

Dear Ms. O'Donnell:

The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky ("Duke Energy Kentucky") notifies the Commission that it will file a general electric rate case in four weeks or reasonably soon thereafter.[1] Duke Energy Kentucky will use a forward-looking test period for this case.

The Commission has ordered Duke Energy Kentucky to file its next general electric rate case such that, based on the applicable suspension period, the new rates will become effective January 1, 2007.[2] We must file our application in late May 2006 to meet this requirement.[3]

We are providing a copy of this notice to the Attorney General's Utility Intervention and Rate Division and to counsel for the other intervenors in our last general electric rate case. We will work diligently with the Commission and our other stakeholders to seek a constructive resolution. Thank you for your consideration.

Sincerely,

Sandra P Meyer

Sandra P. Meyer
President, Duke Energy Kentucky

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1 Duke Energy Kentucky provides this notice pursuant to Commission regulation 807 KAR 5:001 Section 10(2).

2 *See* Finding No. 15 of the Commission's December 5, 2003 Order in Case No. 2003-00252.

3 This late May 2006 application filing date is required by: (1) the Commission's Order to effectuate new rates by January 1, 2007; (2) the 30-day notice period for new rates under KRS 278.180; and (3) the six-month suspension period for forward-looking test period cases under KRS 278.190.

SPM/sew

cc: Chairman Mark David Goss (via overnight mail)
Vice Chairman Theresa J. Hill (via overnight mail)
Commissioner W. Gregory Coker (via overnight mail)
Hon. Gregory D. Stumbo (via overnight mail)
Hon. Dennis G. Howard (via overnight mail)
Hon. Elizabeth E. Blackford (via overnight mail)
Hon. David F. Boehm (via overnight mail)
Hon. Michael L. Kurtz (via overnight mail)
Hon. Anthony G. Martin (via overnight mail)
Hon. Carl J. Melcher (via overnight mail)

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(4)(a)

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807 KAR 5:001, SECTION 10(4)(a)

Description of Filing Requirement:

Sewer utilities shall give the required typewritten notice by mail to all of their customers pursuant to KRS 278.185.

Response:

ULH&P is not a sewer utility; therefore, this section does not apply.

Sponsoring Witness: Sandra P. Meyer

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(4)(b)

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807 KAR 5:001, SECTION 10(4)(b)

Description of Filing Requirement:

Applicants with twenty (20) or fewer customers affected by the proposed general rate adjustment shall mail the required typewritten notice to each customer no later than the date the application is filed with the commission.

Response:

Duke Energy Kentucky has more than 20 customers; therefore, this section does not apply.

Sponsoring Witness: Sandra P. Meyer

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(4)(c)

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807 KAR 5:001, SECTION 10(4)(c)

Description of Filing Requirement:

Except for sewer utilities, applicants with more than twenty (20) customers affected by the proposed general rate adjustment shall give the required notice by one (1) of the following methods:

1. A typewritten notice mailed to all customers no later than the date the application is filed with the commission;

2. Publishing the notice in a trade publication or newsletter which is mailed to all customers no later than the date on which the application is filed with the commission; or

3. Publishing the notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made within seven (7) days of the filing of the application with the commission.

Response:

Duke Energy Kentucky delivered to the local newspapers the notice to customers in the manner required by this section. Within forty-five (45) days of this application, Duke Energy Kentucky will file an affidavit of publication as required.

Sponsoring Witness: Sandra P. Meyer

NOTICE

The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, Inc. ("Duke Energy Kentucky" or "Company") hereby gives notice that it seeks approval by the Kentucky Public Service Commission of an adjustment of electric rates to become effective on and after July 1, 2006. The Commission has docketed this proceeding as Case No. 2006-00172. The proposed electric rates are applicable to the following communities:

Alexandria	Elsmere	Ludlow
Bellevue	Erlanger	Melbourne
Boone County	Fairview	Newport
Bromley	Florence	Park Hills
Campbell County	Fort Mitchell	Pendleton County
Cold Spring	Fort Thomas	Ryland Heights
Covington	Fort Wright-Lookout Heights	Silver Grove
Crescent Park	Grant County	Southgate
Crescent Springs	Highland Heights	Taylor Mill
Crestview	Independence	Union
Crestview Hills	Kenton County	Villa Hills
Crittenden	Kenton Vale	Visalia
Dayton	Lakeside Park	Walton
Dry Ridge	Lakeview	Wilder
Edgewood	Latonia Lakes	Woodlawn

DUKE ENERGY KENTUCKY PRESENT AND PROPOSED RATES

Residential Service – Rate RS
(Electric Tariff Sheet No. 30)

Current Rate

Customer Charge	$3.73 per month
Energy Charge	
Summer Rate	
First 1,000 kilowatt-hours	6.562¢ per kWh
Additional kilowatt-hours	6.873¢ per kWh
Winter Rate	
First 1,000 kilowatt-hours	6.562¢ per kWh
Additional kilowatt-hours	5.059¢ per kWh

Proposed Rate

Customer Charge	$5.00 per month
Energy Charge	
All kilowatt-hours	$0.081299 per kWh

Service at Secondary Distribution Voltage – Rate DS
(Electric Tariff Sheet No. 40)

Current Rate

Customer Charge per month	
Single Phase Service	$5.00 per month
Three Phase Service	$10.00 per month
Demand Charge	
First 15 kilowatts	$0.00 per kW
Additional kilowatts	$6.53 per kW
Energy Charge	
First 6,000 kWh	6.896¢ per kWh
Next 300 kWh/kW	4.210¢ per kWh
Additional kWh	3.497¢ per kWh
Standard "Cap" Rate	19.033¢ per kWh
Church "Cap" Rate	11.295¢ per kWh

Proposed Rate

Customer Charge per month	
Single Phase Service	$7.50 per month
Three Phase Service	$15.00 per month
Demand Charge	
First 15 kilowatts	$0.00 per kW
Additional kilowatts	$8.00 per kW
Energy Charge	
First 6,000 kWh	$0.080731 per kWh
Next 300 kWh/kW	$0.049510 per kWh
Additional kWh	$0.040922 per kWh
Standard "Cap" Rate	$0.235249 per kWh
Church "Cap" Rate	$0.139607 per kWh

Time-of-Day Rate for Service at Distribution Voltage – Rate DT
(Electric Tariff Sheet No. 41)

Current Rate

Customer Charge	
Single Phase	$5.00 per month
Three Phase	$10.00 per month
Primary Voltage Service	$100.00 per month
Demand Charge	
Summer	
On Peak kW	$9.71 per kW
Off Peak kW	$1.00 per kW
Winter	
On Peak kW	$8.03 per kW
Off Peak kW	$1.00 per kW
Energy Charge	
All kWh	3.519¢ per kWh

Primary Voltage Discount:
First 1,000 kW of On Peak billing demand at $0.50 per kW.
Additional kW of On Peak billing demand at $ 0.35 per kW.

Proposed Rate

Base Rate	
Customer Charge	
Single Phase	$7.50 per month
Three Phase	$15.00 per month
Primary Voltage Service	$100.00 per month
Demand Charge	
Summer	
On Peak kW	$11.56 per kW
Off Peak kW	$1.19 per kW
Winter	
On Peak kW	$10.15 per kW
Off Peak kW	$1.19 per kW
Energy Charge	
All kWh	$0.041927 per kWh

Primary Voltage Discount:
First 1,000 kW of On Peak billing demand at $0.65 per kW.
Additional kW of On Peak billing demand at $0.50 per kW.

Optional Rate for Electric Space Heating – Rate EH
(Electric Tariff Sheet No. 42)

Current Rate

A. Winter Period

Customer Charge	
Single Phase Service	$5.00 per month
Three Phase Service	$10.00 per month
Primary Voltage Service	$100.00 per month
Demand Charge	
All kW	$0.00 per kW
Energy Charge	
All kWh	5.150¢ per kWh

B. Summer Billing Period
For energy used during the summer period, the kilowatt demand and kilowatt-hour use shall be billed in accordance with the provisions of the applicable Rate DS or Rate DP.

Proposed Rate

A. Winter Period

Customer Charge	
Single Phase Service	$7.50 per month
Three Phase Service	$15.00 per month
Primary Voltage Service	$100.00 per month
Energy Charge	
All kWh	$0.067222 per kWh

B. Summer Billing Period
For energy used during the summer period, the kilowatt demand and kilowatt-hour use shall be billed in accordance with the provisions of Rate DS or Rate DP.

Seasonal Sports Service – Rate SP
(Electric Tariff Sheet No. 43)

Current Rate

Customer Charge	$5.00 per month
Energy Charge	8.590¢ per kWh

A charge of $10.00 is applicable to each season to cover in part the cost of reconnection of service.

Proposed Rate

Customer Charge	$7.50 per month
Energy Charge	$0.093751 per kWh

A charge of $25.00 is applicable to each season to cover in part the cost of reconnection of service.

Optional Unmetered General Service Rate For Small Fixed Loads – Rate GS-FL
(Electric Tariff Sheet No. 44)

Current Rate

For loads based on a range of 540 to 720 hours use per month of the rated capacity of the connected equipment: 6.791¢ per kWh

For loads of less than 540 hours use per month of the rated capacity of the connected equipment: 7.828¢ per kWh

Minimum: $2.50 per Fixed Load Location per month.

Proposed Rate

For loads based on a range of 540 to 720 hours use per month of the rated capacity of the connected equipment $0.070656 per kWh

For loads of less than 540 hours use per month of the rated capacity of the connected equipment $0.081562 per kWh

Minimum: $2.69 per Fixed Load Location per month.

Service at Primary Distribution Voltage Applicability – Rate DP
(Electric Tariff Sheet No. 45)

Current Rate

Customer Charge per month	
Primary Voltage Service (12.5 or 34.5 kV)	$100.00 per month
Demand Charge	
All kilowatt	$6.08 per kW
Energy Charge	
First 300 kWh	4.252¢ per kWh
Additional kWh	3.510¢ per kWh

Proposed Rate

Customer Charge per month	
Primary Voltage Service (12.5 or 34.5 kV)	$100.00 per month
Demand Charge	
All kilowatts	$7.50 per kW
Energy Charge	
First 300 kWh	$0.051707 per kWh
Additional kWh	$0.043448 per kWh

Time-of-Day Rate for Service at Transmission Voltage – Rate TT
(Electric Tariff Sheet No. 51)

Current Rate

Customer Charge per month	$500.00 per month
Demand Charge	
Summer	
On Peak kW	$6.52 per kW
Off Peak kW	$1.00 per kW
Winter	
On Peak kW	$5.33 per kW
Off Peak kW	$ 1.00 per kW
Energy Charge	
All kWh	3.486¢ per kWh

Proposed Rate

Customer Charge per month	$500.00 per month
Demand Charge	
Summer	
On Peak kW	$7.29 per kW
Off Peak kW	$1.11 per kW
Winter	
On Peak kW	$5.98 per kW
Off Peak kW	$1.11 per kW
Energy Charge	
All kWh	$0.036697 per kWh

Generation Support Service – Rider GSS
(Electric Tariff Sheet No. 58)

Current Rate

1. Administrative Charge	$50.00 per month
2. Monthly Distribution Reservation Charge	
a. Rate DS – Secondary Distribution Service	$2.9056 per kW
b. Rate DT – TOU Secondary Distribution Service	$2.9056 per kW
c. Rate DP – Primary Distribution Service	$2.1570 per kW
d. Rate TT – Transmission Service	$0.4440 per kVA
3. Monthly Transmission Reservation Charge	
a. Rate DS – Secondary Distribution Service	$1.0230 per kW
b. Rate DT – TOU Secondary Distribution Service	$1.0230 per kW
c. Rate DP – Primary Distribution Service	$1.1990 per kW
d. Rate TT – Transmission Service	$1.2480 per kVA
4. Monthly Ancillary Services Reservation Charge	
a. Rate DS – Secondary Distribution Service	$0.5240 per kW
b. Rate DT – TOU Secondary Distribution Service	$0.5240 per kW
c. Rate DP – Primary Distribution Service	$0.5240 per kW
d. Rate TT – Transmission Service	$0.4550 per kVA

Proposed Rate

1. Administrative Charge	$50.00 per month
2. Monthly Distribution Reservation Charge	
a. Rate DS – Secondary Distribution Service	$2.6693 per kW
b. Rate DT – TOU Secondary Distribution Service	$2.4716 per kW
c. Rate DP – Primary Distribution Service	$2.6819 per kW
d. Rate TT – Transmission Service	$0.00 per kVA
3. Monthly Transmission Reservation Charge	
a. Rate DS – Secondary Distribution Service	$1.3153 per kW
b. Rate DT – TOU Secondary Distribution Service	$1.3097 per kW
c. Rate DP – Primary Distribution Service	$1.8710 per kW
d. Rate TT – Transmission Service	$1.2355 per kVA
4. Monthly Ancillary Services Reservation Charge	
a. Rate DS – Secondary Distribution Service	$0.5240 per kW
b. Rate DT – TOU Secondary Distribution Service	$0.5240 per kW
c. Rate DP – Primary Distribution Service	$0.5240 per kW
d. Rate TT – Transmission Service	$0.4550 per kVA

Real Time Pricing – Market-Based Pricing – Rate RTP-M
(Electric Tariff Sheet No. 69)

Current Rate

Secondary Service	$10.00 per month
Primary Service	$100.00 per month
Transmission Service	$500.00 per month
Energy Delivery Charge	
Charge For Each kW Per Hour:	
Secondary Service	$0.010363 per kW per Hour
Primary Service	$0.006462 per kW per Hour
Transmission Service	$0.002433 per kW per Hour

Ancillary Services Charge shall be applied on an hour by hour basis.

Ancillary Services Charge for Each kW Per Hour:	
Secondary Delivery	$0.001002 per kW per Hour
Primary Delivery	$0.000903 per kW per Hour
Transmission Delivery	$0.000778 per kW per Hour

Proposed Rate

Secondary Service	$15.00 per month
Primary Service	$100.00 per month
Transmission Service	$500.00 per month
Energy Delivery Charge	
Charge For Each kW Per Hour:	
Secondary Service	$0.006074 per kW per Hour
Primary Service	$0.005559 per kW per Hour
Transmission Service	$0.002015 per kW per Hour

Ancillary Services Charge shall be applied on an hour by hour basis.

Ancillary Services Charge for Each kW Per Hour:	
Secondary Delivery	$0.000760 per kW per Hour
Primary Delivery	$0.000740 per kW per Hour
Transmission Delivery	$0.000721 per kW per Hour

Street Lighting Service – Rate SL
(Electric Tariff Sheet No. 60)

Current Rate

OVERHEAD DISTRIBUTION AREA

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$4.75
7,000 lumen (Open Refractor)	175	0.205	853	$3.66
10,000 lumen	250	0.275	1,144	$5.11
21,000 lumen	400	0.430	1,789	$6.40
Sodium Vapor				
9,500 lumen	100	0.117	487	$5.95
9,500 lumen (Open Refractor)	100	0.117	487	$4.25
16,000 lumen	150	0.171	711	$6.16
22,000 lumen	200	0.228	948	$7.97
50,000 lumen	400	0.471	1,959	$9.52
Decorative Fixtures				
Sodium Vapor				
9,500 lumen (Rectilinear)	100	0.117	487	$7.60
22,000 lumen (Rectilinear)	200	0.246	1,023	$8.67
50,000 lumen (Rectilinear)	400	0.471	1,959	$10.43
50,000 lumen (Setback)	400	0.471	1,959	$17.16

Where a street lighting fixture served overhead is to be installed on another utility's pole on which the Company does not have a contact, a monthly pole charge will be assessed.

Spans of Secondary Wiring:
For each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.45.

UNDERGROUND DISTRIBUTION AREA

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.210	874	$4.75
7,000 lumen (Open Refractor)	175	0.205	853	$3.66
10,000 lumen	250	0.292	1,215	$5.11
21,000 lumen	400	0.460	1,914	$6.40
Sodium Vapor				
9,500 lumen	100	0.117	487	$5.95
9,500 lumen (Open Refractor)	100	0.117	487	$4.25
16,000 lumen	150	0.171	711	$6.16
22,000 lumen	200	0.228	948	$7.97
50,000 lumen	400	0.471	1,959	$9.52
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$4.98
7,000 lumen (Holophane)	175	0.210	874	$6.61
7,000 lumen (Gas Replica)	175	0.210	874	$17.04
7,000 lumen (Aspen)	175	0.210	874	$10.25
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$8.59
9,500 lumen (Holophane)	100	0.128	532	$9.30
9,500 lumen (Rectilinear)	100	0.117	487	$7.60
9,500 lumen (Gas Replica)	100	0.128	532	$18.30
9,500 lumen (Aspen)	100	0.128	532	$10.91
22,000 lumen (Rectilinear)	200	0.246	1,023	$8.67
50,000 lumen (Rectilinear)	400	0.471	1,959	$10.43
50,000 lumen (Setback)	400	0.471	1,959	$17.16

POLE CHARGES

Pole Description	Pole Type	Rate/Pole
Wood		
17-foot (Wood Laminated) (a)	W17	$3.80
30-foot	W30	$3.75
35-foot	W35	$3.79
40-foot	W40	$4.55
Aluminum		
12-foot (decorative)	A12	$10.41
28-foot	A28	$6.00
28-foot (heavy duty)	A28H	$6.05
30-foot (anchor base)	A30	$11.98
Fiberglass		
17-foot	F17	$3.80
12-foot (decorative)	F12	$11.19
30-foot (bronze)	F30	$7.29
35-foot (bronze)	F35	$7.49
Steel		
27-foot (11 gauge)	S27	$9.84
27-foot (3 gauge)	S27H	$14.83

Spans of Secondary Wiring:
For each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.65.

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of 1.9091¢ per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

OVERHEAD DISTRIBUTION AREA

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$5.46
7,000 lumen (Open Refractor)	175	0.205	853	$4.21
10,000 lumen	250	0.275	1,144	$5.88
21,000 lumen	400	0.430	1,789	$7.36
Metal Halide				
14,000 lumen	175	0.193	803	$5.46
20,500 lumen	250	0.275	1,144	$5.88
36,000 lumen	400	0.430	1,789	$7.36
Sodium Vapor				
9,500 lumen	100	0.117	487	$6.84
9,500 lumen (Open Refractor)	100	0.117	487	$4.89
16,000 lumen	150	0.171	711	$7.08
22,000 lumen	200	0.228	948	$9.16
27,500 lumen	250	0.275	948	$9.16
50,000 lumen	400	0.471	1,959	$10.95
Decorative Fixtures				
Sodium Vapor				
9,500 lumen (Rectilinear)	100	0.117	487	$8.74
22,000 lumen (Rectilinear)	200	0.246	1,023	$9.97
50,000 lumen (Rectilinear)	400	0.471	1,959	$11.99
50,000 lumen (Setback)	400	0.471	1,959	$19.73

Where a street lighting fixture served overhead is to be installed on another utility's pole on which the Company does not have a contact, a monthly pole charge will be assessed.

Spans of Secondary Wiring:
For each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.52.

UNDERGROUND DISTRIBUTION AREA

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.210	874	$5.46
7,000 lumen (Open Refractor)	175	0.205	853	$4.21
10,000 lumen	250	0.292	1,215	$5.88
21,000 lumen	400	0.460	1,914	$7.35
Metal Halide				
14,000 lumen	175	0.210	874	$5.46
20,500 lumen	250	0.292	1,215	$5.88
36,000 lumen	400	0.460	1,914	$7.36
Sodium Vapor				
9,500 lumen	100	0.117	487	$6.84
9,500 lumen (Open Refractor)	100	0.117	487	$4.89
16,000 lumen	150	0.171	711	$7.08
22,000 lumen	200	0.228	948	$9.16
50,000 lumen	400	0.471	1,959	$10.95
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$5.73
7,000 lumen (Holophane)	175	0.210	874	$7.60
7,000 lumen (Gas Replica)	175	0.210	874	$19.59
7,000 lumen (Granville)	175	0.205	853	$5.73
7,000 lumen (Aspen)	175	0.210	874	$11.78
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$5.73
14,000 lumen (Granville Acorn)	175	0.210	874	$11.78
14,000 lumen (Gas Replica)	175	0.210	874	$19.59
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$9.88
9,500 lumen (Holophane)	100	0.128	532	$10.69
9,500 lumen (Rectilinear)	100	0.117	487	$8.74
9,500 lumen (Gas Replica)	100	0.128	532	$21.04
9,500 lumen (Aspen)	100	0.128	532	$12.54
9,500 lumen (Traditionaire)	100	0.117	487	$9.88
9,500 lumen (Granville Acorn)	100	0.128	532	$12.54
22,000 lumen (Rectilinear)	200	0.246	1,023	$9.97
50,000 lumen (Rectilinear)	400	0.471	1,959	$11.99
50,000 lumen (Setback)	400	0.471	1,959	$19.73

POLE CHARGES

Pole Description	Pole Type	Rate/Pole
Wood		
17-foot (Wood Laminated) (a)	W17	$4.37
30-foot	W30	$4.31
35-foot	W35	$4.36
40-foot	W40	$5.23
Aluminum		
12-foot (decorative)	A12	$11.97
28-foot	A28	$6.89
28-foot (heavy duty)	A28H	$6.96
30-foot (anchor base)	A30	$13.76
Fiberglass		
17-foot	F17	$4.37
12-foot (decorative)	F12	$12.87
30-foot (bronze)	F30	$8.38
35-foot (bronze)	F35	$8.60

Steel		
27-foot (11 gauge)	S27	$11.31
27-foot (3 gauge)	S27H	$17.05

Spans of Secondary Wiring:
For each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.75

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of $0.021619 per kilowatt-hour reflecting the base cost of fuel.

Traffic Lighting Service – Rate TL
(Electric Tariff Sheet No. 61)

Current Rate
Where the Company supplies energy only, all kilowatt-hours shall be billed at 3.09 cents per kilowatt hour.

Where the Company supplies energy from a separately metered source and the Company has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 1.80 cents per kilowatt-hour.

Where the Company supplies energy and has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 4.69 cents per kilowatt-hour.

Proposed Rate
Where the Company supplies energy only, all kilowatt-hours shall be billed at $0.035196 per kilowatt-hour.

Where the Company supplies energy from a separately metered source and the Company has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at $0.020695 per kilowatt-hour.

Where the Company supplies energy and has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at $0.055892 per kilowatt-hour.

Unmetered Outdoor Lighting Electric Service – Rate UOLS
(Electric Tariff Sheet No. 62)

Current Rate
All kWh 3.04¢ per kWh

Proposed Rate
All kWh $0.034621 per kWh

Outdoor Lighting Service – Rate OL
(Electric Tariff Sheet No. 65)

Current Rate

Private Outdoor Lighting Units	Lamp Watts	kW/ Luminaire	Annual kWh	Rate/Unit
Standard Fixtures (Cobra Head)				
Mercury Vapor				
7,000 lumen (Open Refractor)	175	0.205	853	$5.98
7,000 lumen	175	0.210	874	$8.04
10,000 lumen	250	0.292	1,215	$9.04
21,000 lumen	400	0.460	1,914	$10.99
Sodium Vapor				
9,500 lumen (Open Refractor)	100	0.117	487	$5.71
9,500 lumen	100	0.117	487	$7.70
16,000 lumen	150	0.171	711	$8.40
22,000 lumen	200	0.228	948	$9.01
50,000 lumen	400	0.471	1,959	$9.03
Decorative Fixtures (a)				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$9.96
7,000 lumen (Holophane)	175	0.210	874	$13.22
7,000 lumen (Gas Replica)	175	0.210	874	$34.08
7,000 lumen (Aspen)	175	0.210	874	$20.50
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$17.18
9,500 lumen (Holophane)	100	0.128	532	$18.60
9,500 lumen (Rectilinear)	100	0.117	487	$15.20
9,500 lumen (Gas Replica)	100	0.128	532	$36.60
9,500 lumen (Aspen)	100	0.128	532	$21.82
22,000 lumen (Rectilinear)	200	0.246	1,023	$17.34
50,000 lumen (Rectilinear)	400	0.471	1,959	$20.86
50,000 lumen (Setback)	400	0.471	1,959	$34.32
A. Flood lighting units served in overhead distribution areas (FL):				
Mercury Vapor				
21,000 lumen	400	0.460	1,914	$11.00
Sodium Vapor				
22,000 lumen	200	0.246	1,023	$6.81
50,000 lumen	400	0.480	1,997	$9.66

Base Fuel Cost:
All kWh shall be subject to a charge of 1.9091 cents per kWh reflecting the base cost of fuel.

Proposed Rate

Private Outdoor Lighting Units	Lamp Watts	kW/ Luminaire	Annual kWh	Rate/Unit
Standard Fixtures (Cobra Head)				
Mercury Vapor				
7,000 lumen (Open Refractor)	175	0.205	853	$6.68
7,000 lumen	175	0.210	874	$9.24
10,000 lumen	250	0.292	1,215	$10.39
21,000 lumen	400	0.460	1,914	$12.64
Metal Halide				
14,000 lumen	175	0.210	874	$9.24
20,500 lumen	250	0.307	1,215	$10.39
36,000 lumen	400	0.460	1,914	$12.64
Sodium Vapor				
9,500 lumen (Open Refractor)	100	0.117	487	$6.57
9,500 lumen	100	0.117	487	$8.85
16,000 lumen	150	0.171	711	$9.66
22,000 lumen	200	0.228	948	$10.36
27,500 lumen	250	0.228	948	$10.36
50,000 lumen	400	0.471	1,959	$10.38
Decorative Fixtures (a)				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$11.45
7,000 lumen (Holophane)	175	0.210	874	$15.20
7,000 lumen (Gas Replica)	175	0.210	874	$39.18
7,000 lumen (Aspen)	175	0.210	874	$23.57
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$11.45
14,000 lumen (Granville Acorn)	175	0.210	874	$23.57
14,000 lumen (Gas Replica)	175	0.210	874	$39.18
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$19.75
9,500 lumen (Holophane)	100	0.128	532	$21.39
9,500 lumen (Rectilinear)	100	0.117	487	$17.48
9,500 lumen (Gas Replica)	100	0.128	532	$42.06
9,500 lumen (Aspen)	100	0.128	532	$25.09
9,500 lumen (Traditionaire)	100	0.117	487	$19.75
9,500 lumen (Granville Acorn)	100	0.128	532	$25.09
22,000 lumen (Rectilinear)	200	0.246	1,023	$19.94
50,000 lumen (Rectilinear)	400	0.471	1,959	$23.98
50,000 lumen (Setback)	400	0.471	1,959	$39.46
A. Flood lighting units served in overhead distribution areas (FL):				
Mercury Vapor				
21,000 lumen	400	0.460	1,914	$12.65
Metal Halide				
20,500 lumen	250	0.307	1,215	$10.39
36,000 lumen	400	0.460	1,914	$12.65
Sodium Vapor				
22,000 lumen	200	0.246	1,023	$10.13
30,000 lumen	250	0.312	1,023	$10.13
50,000 lumen	400	0.480	1,997	$11.11

Base Fuel Cost:
All kWh shall be subject to a charge of $0.021619 per kWh reflecting the base cost of fuel.

Street Lighting Service for Non-Standard Units – Rate NSU
(Electric Tariff Sheet No. 66)

Current Rate

Company-Owned Units	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Boulevard units served underground				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$6.82
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$4.75
Holophane Decorative fixture on 17-foot fiberglass pole served underground with direct buried cable				
a. 10,000 lumen Mercury Vapor	250	0.292	1,215	$12.24

The cable span charge of $.65 per each increment of 25 feet of secondary wiring shall be added to the Rate/unit charge for each increment of secondary wiring beyond the first 25 feet from the pole base.

Street light units served overhead distribution				
a. 2,500 lumen Incandescent	189	0.189	786	$4.70
b. 2,500 lumen Mercury Vapor	100	0.109	453	$4.95
c. 21,000 lumen Mercury Vapor	400	0.460	1,914	$5.79
Customer owned				
Steel boulevard units served underground with limited maintenance by Company				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$3.58
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$4.55

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of 1.9091¢ per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

Company owned	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Boulevard units served underground				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$7.84
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$5.46
Holophane Decorative fixture on 17-foot fiberglass pole served underground with direct buried cable				
a. 10,000 lumen Mercury Vapor	250	0.292	1,215	$14.07

The cable span charge of $.75 per each increment of 25 feet of secondary wiring shall be added to the Rate/unit charge for each increment of secondary wiring beyond the first 25 feet from the pole base.

Street light units served overhead distribution				
a. 2,500 lumen Incandescent	189	0.189	786	$5.40
b. 2,500 lumen Mercury Vapor	100	0.109	453	$5.69
c. 21,000 lumen Mercury Vapor	400	0.460	1,914	$6.63
Customer owned				
Steel boulevard units served underground with limited maintenance by Company				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$4.12
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$5.23

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of $0.021619 per kilowatt-hour reflecting the base cost of fuel.

Private Outdoor Lighting for Non-Standard Units – Rate NSP
(Electric Tariff Sheet No. 67)

Current Rate
A. Private outdoor lighting units:
The following monthly charge will be assessed for existing facilities, but this unit will not be available to any new customers after May 15, 1973:

	Lamp Watts	kW/ Unit	Annual kWh	Rate/Unit
2,500 lumen Mercury, Open Refractor	100	0.115	478	$5.84
2,500 lumen Mercury, Enclosed Refractor	100	0.115	478	$8.29

B. Outdoor lighting units served in underground residential distribution areas:
The following monthly charge will be assessed for existing fixtures which include lamp and luminaire, controlled automatically, with an underground service wire not to exceed 35 feet from the service point, but these units will not be available to new customers after May 5, 1992:

	Lamp Watts	kW/ Unit	Annual kWh	Rate/Unit
7,000 lumens Mercury, Mounted on a 17-foot Fiberglass Pole.	175	0.205	853	$10.95
7,000 lumen Mercury, Mounted on a 17-foot Wood Laminated Pole (a)	175	0.205	853	$10.95
7,000 lumen Mercury, Mounted on a 30-foot Wood Pole	175	0.205	853	$10.01
9,500 lumen Sodium Vapor, TC 100 R	100	0.117	487	$8.73

(a) Note: New or replacement poles are not available.

C. Flood lighting units served in overhead distribution areas:
The following monthly charge will be assessed for each existing fixture, which includes lamp and luminaire, controlled automatically, mounted on a utility pole, as specified by the Company, with a span of wire not to exceed 120 feet, but these units will not be available after May 5, 1992:

	Lamp Watts	kW/ Fixture	Annual kWh	Rate/Unit
52,000 lumen Mercury (35-foot Wood Pole)	1,000	1.102	4,584	$16.47
52,000 lumen Mercury (50-foot Wood Pole)	1,000	1.102	4,584	$19.55
50,000 lumen Sodium Vapor	400	0.471	1,959	$13.53

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of 1.9091¢ per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate
A. Private outdoor lighting units:
The following monthly charge will be assessed for existing facilities, but this unit will not be available to any new customers after May 15, 1973:

	Lamp Watts	kW/ Unit	Annual kWh	Rate/Unit
2,500 lumen Mercury, Open Refractor	100	0.115	478	$6.71
2,500 lumen Mercury, Enclosed Refractor	100	0.115	478	$9.53

B. Outdoor lighting units served in underground residential distribution areas:
The following monthly charge will be assessed for existing fixtures which include lamp and luminaire, controlled automatically, with an underground service wire not to exceed 35 feet from the service point, but these units will not be available to new customers after May 5, 1992:

	Lamp Watts	kW/ Unit	Annual kWh	Rate/Unit
7,000 lumen Mercury, Mounted on a 17-foot Fiberglass Pole	175	0.205	853	$12.59
7,000 lumen Mercury, Mounted on a 17-foot Wood Laminated Pole (a)	175	0.205	853	$12.59
7,000 lumen Mercury, Mounted on a 30-foot Wood Pole	175	0.205	853	$11.51
9,500 lumen Sodium Vapor, TC 100 R	100	0.117	487	$10.04

(a) Note: New or replacement poles are not available.

C. Flood lighting units served in overhead distribution areas:
The following monthly charge will be assessed for each existing fixture, which includes lamp and luminaire, controlled automatically, mounted on a utility pole, as specified by the Company, with a span of wire not to exceed 120 feet, but these units will not be available after May 5, 1992:

	Lamp Watts	kW/ Fixture	Annual kWh	Rate/Unit
52,000 lumen Mercury (35-foot Wood Pole)	1,000	1.102	4,584	$18.94
52,000 lumen Mercury (50-foot Wood Pole)	1,000	1.102	4,584	$22.48
50,000 lumen Sodium Vapor	400	0.471	1,959	$15.56

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of $0.021619 per kilowatt-hour reflecting the base cost of fuel.

Street Lighting Service-Customer Owned – Rate SC
(Electric Tariff Sheet No. 68)

Current Rate

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$2.25
10,000 lumen	250	0.275	1,144	$2.66
21,000 lumen	400	0.430	1,789	$3.35
Sodium Vapor				
9,500 lumen	100	0.117	487	$3.46
16,000 lumen	150	0.171	711	$3.66
22,000 lumen	200	0.228	948	$3.72
50,000 lumen	400	0.471	1,959	$3.89
Decorative Fixture				
Mercury Vapor				
7,000 lumen (Holophane)	175	0.210	874	$3.12
7,000 lumen (Town & Country)	175	0.205	853	$3.11
7,000 lumen (Gas Light Replica)	175	0.210	874	$3.12
7,000 lumen (Aspen)	175	0.210	874	$3.12
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$3.47
9,500 lumen (Rectilinear)	100	0.117	487	$3.47
9,500 lumen (Aspen)	100	0.128	532	$3.58
9,500 lumen (Holophane)	100	0.128	532	$3.58
9,500 lumen (Gas Light Replica)	100	0.128	532	$3.58
22,000 lumen (Rectilinear)	200	0.246	1,023	$3.92
50,000 lumen (Rectilinear)	400	0.471	1,959	$4.14

Where a street lighting fixture served overhead is to be installed on another utility's pole on which the Company Does not have a contact, a monthly pole charge will be assessed.

Pole Description	Pole Type	Rate/Pole
Wood		
30-foot	W30	$3.75
35-foot	W35	$3.79
40-foot	W40	$4.54

Customer Owned and Maintained Units
All kWh shall be billed at 3.04¢ per kWh plus applicable riders.

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of 1.9091¢ per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$2.59
10,000 lumen	250	0.275	1,144	$3.06
21,000 lumen	400	0.430	1,789	$3.65
Metal Halide				
14,000 lumen	175	0.193	803	$2.59
20,500 lumen	250	0.275	1,144	$3.06
36,000 lumen	400	0.430	1,789	$3.85
Sodium Vapor				
9,500 lumen	100	0.117	487	$3.98
16,000 lumen	150	0.171	711	$4.21
22,000 lumen	200	0.228	948	$4.28
27,500 lumen	250	0.228	948	$4.28
50,000 lumen	400	0.471	1,959	$4.47
Decorative Fixture				
Mercury Vapor				
7,000 lumen (Holophane)	175	0.210	874	$3.59
7,000 lumen (Town & Country)	175	0.205	853	$3.58
7,000 lumen (Gas Replica)	175	0.210	874	$3.59
7,000 lumen (Aspen)	175	0.210	874	$3.59
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$3.58
14,000 lumen (Granville Acorn)	175	0.210	874	$3.59
14,000 lumen (Gas Replica)	175	0.210	874	$3.59
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$3.99
9,500 lumen (Traditionaire)	100	0.117	487	$3.99
9,500 lumen (Granville Acorn)	100	0.128	532	$4.12
9,500 lumen (Rectilinear)	100	0.117	487	$3.99
9,500 lumen (Aspen)	100	0.128	532	$4.12
9,500 lumen (Holophane)	100	0.128	532	$4.12
9,500 lumen (Gas Replica)	100	0.128	532	$4.12
22,000 lumen (Rectilinear)	200	0.246	1,023	$4.51
50,000 lumen (Rectilinear)	400	0.471	1,959	$4.76

Pole Description	Pole Type	Rate/Pole
Wood		
30-foot	W30	$4.31
35-foot	W35	$4.36
40-foot	W40	$5.23

Customer Owned and Maintained Units
All kWh shall be billed at $0.034521 per kWh plus applicable riders.

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of $0.021619 per kilowatt-hour reflecting the base cost of fuel.

Street-lighting Service-Overhead Equivalent – Rate SE
(Electric Tariff Sheet No. 69)

Current Rate

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$4.75
7,000 lumen (Holophane)	175	0.210	874	$4.75
7,000 lumen (Gas Replica)	175	0.210	874	$4.75
7,000 lumen (Aspen)	175	0.210	874	$4.75
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$5.95
9,500 lumen (Holophane)	100	0.128	532	$5.95
9,500 lumen (Rectilinear)	100	0.117	487	$5.95
9,500 lumen (Gas Replica)	100	0.128	532	$5.95
9,500 lumen (Aspen)	100	0.128	532	$5.95
22,000 lumen (Rectilinear)	200	0.246	1,023	$7.97
50,000 lumen (Rectilinear)	400	0.471	1,959	$9.52
50,000 lumen (Setback)	400	0.471	1,959	$9.52

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of 1.9091¢ per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$5.46
7,000 lumen (Holophane)	175	0.210	874	$5.46
7,000 lumen (Gas Replica)	175	0.210	874	$5.46
7,000 lumen (Aspen)	175	0.210	874	$5.46
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$5.46
14,000 lumen (Granville Acorn)	175	0.210	874	$5.46
14,000 lumen (Gas Replica)	175	0.210	874	$5.46
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$6.84
9,500 lumen (Holophane)	100	0.128	532	$6.84
9,500 lumen (Rectilinear)	100	0.117	487	$6.84
9,500 lumen (Gas Replica)	100	0.128	532	$6.84
9,500 lumen (Aspen)	100	0.128	532	$6.84
9,500 lumen (Traditionaire)	100	0.117	487	$6.84
9,500 lumen (Granville Acorn)	100	0.128	532	$6.84
22,000 lumen (Rectilinear)	200	0.246	1,023	$9.16
50,000 lumen (Rectilinear)	400	0.471	1,959	$10.95
50,000 lumen (Setback)	400	0.471	1,959	$10.95

Base Fuel Cost
All kilowatt-hours shall be subject to a charge of $0.021619 per kilowatt-hour reflecting the base cost of fuel.

Transmission Cost Recovery Mechanism – Rider TCRM
(Electric Tariff Sheet No. 83)

Current Rate This rider is currently not available.

Proposed Rate
Applicability
Applicable to all jurisdictional retail customers in the Company's electric service area.

Whenever the average cost of transmission charged to the Company by its Regional Transmission Organization is greater or less than the average cost of this transmission included per kilowatt-hour of sales in the base period, there shall be added to or subtracted from the net monthly bill to which this Rider is applicable, an amount determined by multiplying the number of kilowatt-hours consumed by the customer for which the bill is rendered by a Rider TCRM adjustment.

1. The charge per kilowatt-hour delivered under the rate schedule to which this adjustment is applicable shall be increased or decreased during each year in accordance with the following formula:

$$\text{Adjustment Factor} = \frac{T(y)}{S(y)} - \frac{T(b)}{S(b)}$$

Where:
a. "T" is the transmission related Midwest ISO costs billed to Duke Energy Kentucky.
b. "S" is the kilowatt-hour sales.
c. "y" is the current year.
d. "b" is the base year.

Backup Delivery Point Capacity Rider – Rider BDP
(Electric Tariff Sheet No. 84)

Current Rate This rider is currently not available.

Proposed Rate
Backup Delivery Point Capacity Rider
The Company will normally supply service to one premises at one standard voltage at one delivery point and through one meter to a Non-Residential Customer in accordance with the provisions of the applicable rate schedule and the Electric Service Regulations. Upon customer request, Company will make available to a Non-Residential Customer additional delivery points in accordance with the rates, terms and conditions of this Rider BDP.

Net Monthly Bill
1. Connection Fee: The Connection Fee applies only if an additional metering point is required.
2. Monthly charges will be based on the unbundled distribution and/or transmission rates of the customer's most applicable rate schedule and the contracted for reserve backup delivery point capacity.
3. The Customer shall also be responsible for the acceleration of costs, if any, that would not have otherwise been incurred by Company

absent such request for additional delivery points. The terms of payment may be made initially or over a pre-determined term mutually agreeable to Company and Customers that shall not exceed the minimum term. In each request for service under this Rider, Company engineers will conduct a thorough review of the customer's request and the circuits affected by the request. The customer's capacity needs will be weighed against the capacity available on the circuit, anticipated load growth on the circuit, and any future construction plans that may be advanced by the request.

Green Power Rider – Rider GP
(Electric Tariff Sheet No. 88)

Current Rate

Applicability

Applicable to all customers who want to contribute to a Company-sponsored "Green Power" fund. The term of this pilot program is three (3) years.

Definition of Green Power

Green Power includes energy generated from environmentally friendly sources, including, but not limited to: hydroelectric generation, photovoltaic generation, solar thermal generation, wind generation, biomass generation, and methane recovery.

Net Monthly Bill

Customers who participate in this Rider will be billed for electric service under all standard applicable tariffs and riders. The customer's contribution to the Green Power fund will be added to the customer's bill for electric service.

Proposed Rate

Applicability

Applicable to all customers who wish to purchase "Green Power" from the Company-sponsored "Green Power" program. This rider will be available until December 31, 2008.

Definition of Green Power

Green Power includes energy generated from renewable and/or environmentally friendly sources, including: Wind, Solar Photovoltaic, Biomass Co-firing of Agricultural Crops and All energy crops, Hydro – as certified by the Low Impact Hydro Institute, Incremental Improvements in Large Scale Hydro, Coal Mine Methane, Landfill Gas, Biogas Digesters, Biomass Co-firing of All Woody Waste including mill residue, but excluding painted or treated lumber.

Green Power includes the purchase of Renewable Energy Certificates and/or Carbon Credits from the sources described above.

Green Power Rate

1. Rate RS
   For all Green Power kWh, including carbon credits, purchased per month $0.025 per kWh. Minimum purchase is 200 kWh. Additional purchases to be made in 100 kWh block increments.
2. All other rates
   Individually calculated Green Power Rate per service agreement which may also include carbon credits.

Net Metering Rider – Rider NM
(Electric Tariff Sheet No. 89)

Current Rate

Availability

Net Metering is provided upon request and on a first-come, first-served basis. Net Metering is available to customers with a capacity of 15 kW or less. The total nameplate rating of all customer-generators under net metering is limited to one-percent (1%) of the Company's total peak system load.

Proposed Rate

Availability

Net Metering is provided upon request and on a first-come, first-served basis. Net Metering is available to customers with a capacity of 15 kW or less. At its sole discretion, Company may provide Net Metering to other customers on a case-by-case basis. The total nameplate rating of all customer-generators under net metering is limited to one-percent (1%) of the Company's total peak system load.

Charge for Reconnection of Service
(Electric Tariff Sheet No. 91)

Current Rate

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be twenty-five dollars ($25.00).
B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be twenty-five dollars ($25.00).
C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of twenty-five dollars ($25.00) the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for electricity used, prior to the reconnection of service.
D. If both the gas and electric services are reconnected at one time, the total charge shall not exceed thirty-eight dollars ($38.00).

Proposed Rate

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be twenty-five dollars ($25.00).
B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be twenty-five dollars ($25.00).
C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of twenty-five dollars ($25.00) the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for electricity used, prior to the reconnection of service.
D. If both the gas and electric services are reconnected at one time, the total charge shall not exceed thirty-eight dollars ($38.00).
E. Where electric service was disconnected at the pole because the Company was unable to gain access to the meter, the reconnection charge shall be sixty-five dollars ($65.00). If the gas service is also reconnected the charge shall be ninety dollars ($90.00).
F. If the Company receives notice after 12:30 p.m. of a customer's desire for same day reinstatement of service and if the service cannot be performed during normal business hours, the after hours reconnection charge for connection at the meter shall be fifty dollars ($50.00). The after hours charge for reconnection at the pole shall be ninety dollars ($90.00).
G. If a Company employee, whose original purpose was to disconnect the service, has provided the customer a means to avoid disconnection, service which otherwise would have been disconnected shall remain intact, and no reconnection charge shall be assessed. However, a collection charge of fifteen dollars ($15.00) may be assessed.

Cogeneration and Small Power Production Sale and Purchase Tariff – 100 kW or Less
(Electric Tariff Sheet No. 93)

Current Rate

Rates for Purchases from qualifying facilities:

Purchase Rate shall be 1.95¢/kWh for all kilowatt-hours delivered.

Proposed Rate

Rates for Purchases from qualifying facilities:

Purchase Rate shall be $0.03078/kWh for all kilowatt-hours delivered.

Cogeneration and Small Power Production Sale and Purchase Tariff – Greater Than 100 kW
(Electric Tariff Sheet No. 94)

Current Rates

Rate Schedules

Rates for Purchase from qualifying facilities:

The Purchase Rate for all kilowatt-hours delivered shall be determined according to the standard calculation of avoided costs as set forth herein.

Rates for Sales to qualifying facilities will be accomplished through existing tariff schedules on file with the Ky. PSC.

Calculation of Avoided Cost

The methodology to determine avoided cost involves the use of the Electric Generation Expansion Analysis System, (EGEAS) to develop differential long run marginal costs between Duke Energy Ohio/Duke Energy Kentucky's optimum base case generation expansion plan and an optimum expansion plan including the QF. The key feature of the methodology is the complete reoptimization of the base case generation expansion plan including capital costs, fuel cost, and operation and maintenance expenses to insure that the ratepayer will remain indifferent toward the capacity and energy cost of any cogenerator or small power producer.

Sample Rates:

Cogen/Spp Contract Length	Capacity Component	Weighted Energy Component	Total Cogen/Spp Credit (¢/kWh/All Hours)
5 Yr	0.81¢/kWh	1.95¢/kWh	2.76¢/kWh
10 Yr.	1.16¢/kWh	1.95¢/kWh	3.11¢/kWh
15 Yr.	1.63¢/kWh	1.95¢/kWh	3.58¢/kWh
20 Yr	2.92¢/kWh	1.95¢/kWh	4.87¢/kWh

Proposed Rates:

Rate Schedules

Rates for Purchase from qualifying facilities:

The Purchase Rate for all kilowatt-hours delivered shall be the locational marginal price for power purchased through the Midwest ISO day-ahead energy market, inclusive of the energy, congestion and losses charges, delivered to the Duke Energy Kentucky commercial price node.

Rates for Sales to qualifying facilities will be accomplished through existing tariff schedules on file with the Kentucky PSC.

Real Time Pricing Program – Rate RTP
(Electric Tariff Sheet No. 99)

Current Rate

ENERGY DELIVERY CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Service	$0.004800 per kW Per Hour
Primary Service	$0.004600 per kW Per Hour
Transmission Service	$0.001600 per kW Per Hour

ANCILLARY SERVICES CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Delivery	$0.000760 per kW Per Hour
Primary Delivery	$0.000740 per kW Per Hour
Transmission Delivery	$0.000721 per kW Per Hour

DSMR CHARGE

All kWh, adjusted to reflect required metering adjustments under this rate schedule, shall be subject to application of the amount per kWh stated on Sheet No. 78, Rider DSMR, Demand Side Management Rate (DSMR)

PROGRAM CHARGE

Company will provide Internet based communication software to be used to provide Customer with the Price Quotes. Customer will be responsible for providing its own Internet access. A charge of $150.00 per billing period per site shall be added to Customer's bill to cover the additional billing, administrative, and cost of communicating the hourly Price Quotes associated with the RTP Program.

SPECIAL TERMS AND CONDITIONS

Except as provided in this Rate RTP, all terms, conditions, rates and charges outlined in the Standard Rate Schedule will apply. Participation in the RTP Program will not affect Customer's obligations for electric service under the Standard Rate Schedule.

Customers receiving service under Rider IS or a special contract that contains an interruptible service provision will be unable to participate in the RTP Program. Adjustments will be made to the CBL to reflect the interruptible service.

Customers who terminate their service agreement under this Rider RTP after the initial one (1) year term shall be ineligible to return to the program for twelve (12) months from the termination date.

The primary term of service is one (1) year consisting of a consecutive twelve month period.

Customers returning to the standard tariff shall have any historical demands in excess of the CBL, waived for purposes of calculating applicable billing demands.

The supplying and billing for service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's Service Regulations currently in effect, as filed with the Kentucky Public Service Commission.

Proposed Rate

ENERGY DELIVERY CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Service	$0.006074 per kW Per Hour
Primary Service	$0.005559 per kW Per Hour
Transmission Service	$0.002015 per kW Per Hour

ANCILLARY SERVICES CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Delivery	$0.000760 per kW Per Hour
Primary Delivery	$0.000740 per kW Per Hour
Transmission Delivery	$0.000721 per kW Per Hour

PROGRAM CHARGE

Company will provide Internet based communication software to be used to provide Customer with the Price Quotes. Customer will be responsible for providing its own Internet access. A charge of $150.00 per billing period per site shall be added to Customer's bill to cover the additional billing, administrative, and cost of communicating the hourly Price Quotes associated with the RTP Program.

SPECIAL TERMS AND CONDITIONS

Except as provided in this Rate RTP, all terms, conditions, rates and charges outlined in the Standard Rate Schedule will apply. Participation in the RTP Program will not affect Customer's obligations for electric service under the Standard Rate Schedule.

Customers who terminate their service agreement under this Rider RTP after the initial one (1) year term shall be ineligible to return to the program for twelve (12) months from the termination date.

The primary term of service is one (1) year consisting of a consecutive twelve month period.

Customers returning to the standard tariff shall have any historical demands in excess of the CBL, waived for purposes of calculating applicable billing demands.

The supplying and billing for service and all conditions applying thereto, are subject to the jurisdiction of the Kentucky Public Service Commission, and to the Company's Service Regulations currently in effect, as filed with the Kentucky Public Service Commission.

Fuel Cost Adjustment – Rider F
(Electric Tariff Sheet No. 80)

Current Rate

It has been determined that the base period fuel cost [F(b)/S(b)] as of August 1, 1983 is 1.9091 cents per kilowatt-hour.

Notwithstanding the above Fuel Cost Adjustment provisions, the company's FAC rate shall be fixed at (0.2525) cents per kilowatt-hour effective with Billing Cycle 1, June 2001.

Proposed Rate (now titled Rider FAC)

Fuel Adjustment Calculation

1. The monthly amount computed under each of the rate schedules to which this fuel clause is applicable shall be increased or (decreased) at a rate per kilowatt-hour of monthly consumption in accordance with the following formula:

$$\text{Fuel Cost Adjustment} = \frac{F(m)}{S(m)} - \$0.021619$$

Where F is the expense of fuel in the second preceding month and S is the sales in the second preceding month, as defined below:

2. Fuel costs (F) shall be the cost of:
   A. Fossil fuel consumed in the Company's plants plus the cost of fuel which would have been used in Plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, plus
   B. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) of this subsection, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus
   C. The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to each transaction) when such energy is purchased on an economic dispatch basis. Included therein are such costs as the charges for economy energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy, and; less
   D. The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic basis.
   E. All fuel costs shall be based on a weighted-average inventory costing. The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of fuel itself and necessary charges for transportation of fuel from the point of acquisition to the unloading point, as listed in Account 151 of the FERC Uniform System of Accounts for Public Utilities and Licensees.
   F. As used herein, the term "forced outages" means all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection, or acts of the public enemy, then the Company may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment
3. Sales (S) shall be determined in kilowatt-hours as follows:

   Add:

   A. net generation
   B. purchases
   C. interchange in

   Subtract:

   D. inter-system sales including economy energy and other energy sold on an economic dispatch basis.
   E. total system losses

Duke Energy Kentucky proposes the following new tariff schedules: Rider BDP, Backup Delivery Point Capacity Rider; and, Rider TCRM, Transmission Cost Recovery Mechanism. The following tariff schedules are proposed to be eliminated: Sheet No. 70, Rider SES, Standby or Emergency Service; Sheet No. 74, Rider IS, Interruptible Service Rider; Sheet No. 76, Rider TES, Thermal Energy Storage Rider; and, Sheet No. 79, Rider EOP-RTP, Energy Call Option Program.

In addition, Duke Energy Kentucky proposes to change the text of the following tariff schedules: Sheet No. 20, Service Regulations, Section I - Service Agreement; Sheet No. 23, Service Regulations, Section IV – Company's Installation; Sheet No. 77, Rider PLM, Peak Load Management Rider.

The foregoing rates reflect a proposed increase in electric revenues of approximately $66.6 million or 27.8% over current total electric revenues to Duke Energy Kentucky. The estimated amount of this increase per rate class is shown below. The average monthly bill for each rate class to which the proposed rate will apply are also shown in the table below.

Tariff Description	Revenue Increase Dollars ($)	Revenue Increase Percent (%)	Average Bill Increase Dollars ($)	Average Bill Increase Percent (%)
Rate RS, Residential Service	32,634,829	33.42	19.48	30.0
Total Residential Customer Class	32,634,829	33.42	19.48	30.0
Rate DS, Distribution Voltage Service	15,712,565	23.60	142.64	23.0
Rate DT, TOD Rate for Distribution Voltage – Prim.	5,298,878	26.68	5,968.93	28.0
Rate DT, TOD Rate for Distribution Voltage – Sec.	10,176,341	26.52	5,968.93	28.0
Rate EH, Optional Electric Space Heating Rate	259,701	37.39	176.53	38.4
Rate SP, Seasonal Sports Service	4,971	14.16	15.17	13.9
Rate GS-FL, Small Fixed Load Rate	36,174	7.67	3.51	7.4
Rate DP, Primary Voltage Service	498,707	28.26	3,834.44	27.2
Total Distribution Customer Class	31,987,337	25.03	10,141.22	27.7
Rate TT, Transmission Voltage Service	1,465,160	17.17	9,622.00	16.2
Total Transmission Customer Class	1,465,160	17.17	9,622.00	16.2
Rate DT-RTP-Prim. – Real Time Pricing	19,840	2.49	71.22	3.4
Rate DT-RTP-Sec. – Real Time Pricing	11,057	3.22	253.95	2.8
Rate DS-RTP – Real Time Pricing	2,468	3.52	147.66	3.8
Rate TT-RTP – Real Time Pricing	5,565	1.38	5,013.00	1.2
Total Real Time Pricing Customer Class	38,570	2.41	5,485.83	1.3
Rate SL, Street Lighting Service	203,869	17.51	1.43	17.5
Rider TL, Traffic Lighting Service	54,767	20.90	0.62	20.9
Rider UOLS, Unmetered Outdoor Lighting Service	88	24.31	0.80	24.3
Rider OL, Outdoor Lighting Service	91,749	17.59	1.77	17.6
Rider NSU, Street Lighting – Non-Standard Units	9,229	17.17	1.06	17.2
Rider NSP, Outdoor Lighting – Non-Standard Units	7,437	16.63	1.43	16.6
Rate SC, Street Lighting – Customer-Owned	760	24.00	0.35	24.0
Rate SE, Street Lighting – Overhead Equivalent	25,052	17.39	1.10	17.4
Total Lighting Customer Class	392,971	17.91	1.22	17.9

The rates contained in this notice are the rates proposed by Duke Energy Kentucky; however, the Kentucky Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. Such action may result in rates for consumers other than the rates in this notice.

Any corporation, association, body politic or person with a substantial interest in the matter may, by written request within thirty (30) days after publication of this notice of the proposed rate changes, request leave to intervene; intervention may be granted beyond the thirty (30) day period for good cause shown. Such motion shall be submitted to the Kentucky Public Service Commission, P. O. Box 615, 211 Sower Boulevard, Frankfort, Kentucky 40602-0615, and shall set forth the grounds for the request including the status and interest of the party.

Intervenors may obtain copies of the application and other filings made by the Company by contacting Ms. Anita Schafer of Duke Energy Kentucky at the address specified below or by telephone at (513) 287-3842. A copy of the application and other filings made by the Company is available for public inspection at the Commission's office in Frankfort, Kentucky, and at the following Company offices: 1697 A Monmouth Street, Newport, KY 41071.

For further information contact:

PUBLIC SERVICE COMMISSION
COMMONWEALTH OF KENTUCKY
P. O. BOX 615
211 SOWER BOULEVARD
FRANKFORT, KENTUCKY 40602-0615
(502) 564-3940

DUKE ENERGY KENTUCKY
1697 A MONMOUTH STREET
NEWPORT, KENTUCKY 41071
(513) 287-3842

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(4)(d)

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807 KAR 5:001, SECTION 10(4)(d)

Description of Filing Requirement:

If notice is published, an affidavit from the publisher verifying that the notice was published, including the dates of the publication with an attached copy of the published notice, shall be filed with the Commission no later than forty-five (45) days of the filed date of the application.

Response:

Duke Energy Kentucky delivered to the local newspapers the notice to customers in the manner required by this section. Within forty-five (45) days of this application, Duke Energy Kentucky will file an affidavit of publication as required.

Sponsoring Witness: Sandra P. Meyer

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(4)(e)

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807 KAR 5:001, SECTION 10(4)(e)

Description of Filing Requirement:

If notice is mailed, a written statement signed by the utility's chief officer in charge of Kentucky operations verifying the notice was mailed shall be filed with the Commission no later than thirty (30) days of the filed date of the application.

Response:

The customer notice was published; therefore, this section does not apply.

Sponsoring Witness: Sandra P. Meyer

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(4)(f)

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807 KAR 5:001, SECTION 10(4)(f)

Description of Filing Requirement:

All utilities, in addition to the above notification, shall post a sample copy of the required notification at their place of business no later than the date on which the application is filed which shall remain posted until the commission has finally determined the utility's rates.

Response:

Duke Energy Kentucky has posted a sample copy of the required notifications at its place of business, as required. The locations of the Company's offices are at 1697-A Monmouth, Newport, Kentucky.

Sponsoring Witness: Sandra P. Meyer

CERTIFICATE OF NOTICE TO THE PUBLIC OF CHANGE
IN TARIFF WHICH RESULTS IN INCREASED RATES

To the Public Service Commission, Frankfort, Ky.

Pursuant to the Rules Governing Tariffs, I hereby certify that I am President of The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio ("Duke Energy Ohio") and President of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky, a utility furnishing gas and electric service within the Commonwealth of Kentucky, which on or about the 31st day of May, 2006 issued its new Electric Tariff KY.P.S.C. No. 1, cancelling its former Electric Tariff KY.P.S.C. No. 1, to become effective July 1, 2006 and that notice to the public of the issuing of the same is being given in all respects as required by Section 8 of said administrative regulation, as follows:

On the 31st day of May, 2006, the same will be exhibited for public inspection at the offices and places of business of the Company in the territory affected thereby, to wit, at the following places: 1697A Monmouth Street, Newport, Kentucky 41071, and that the same will be kept open to public inspection at said offices and places of business in conformity with the requirements of Section 8 of said administrative regulation.

That more than 20 customers will be affected by said change by way of an increase in their rates or charges, and on or about the 31st day of May, 2006 there will be delivered to the Kentucky Enquirer and Kentucky Post, newspapers of general circulation in the communities in which the customers affected reside, for publication therein once a week for three consecutive weeks prior to the effective date of said change, a notice of the proposed rates or administrative regulations, a copy of said notice being attached hereto. A certificate of the publication of said notice will be furnished to the Public Service Commission upon the completion of the same in accordance with Section 9(2), of said administrative regulation.

Given under my hand this 25 day of May, 2006

Sandra P. Meyer
President, Duke Energy Ohio
President, Duke Energy Kentucky
139 East Fourth Street
P.O. Box 960
Cincinnati, Ohio 45201-0960

#185911

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(5)

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807 KAR 5:001, SECTION 10(5)

Description of Filing Requirement:

Notice of hearing scheduled by the commission upon application by a utility for a general adjustment in rates shall be advertised by the utility by newspaper publication in the areas that will be affected in compliance with KRS 424.300.

Response:

Duke Energy Kentucky will publish notice of hearing after the Commission has established the schedule for the hearing.

Sponsoring Witness: Sandra P. Meyer

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(8)(a)

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807 KAR 5:001, SECTION 10(8)(a)

Description of Filing Requirement:

Financial data for the Forecasted Period shall be in the form of adjustments to the Base Period.

Response:

See Schedules D-2.1 through D-2.14.

Sponsoring Witness: William Don Wathen, Jr.

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(8)(b)

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807 KAR 5:001, SECTION 10(8)(b)

Description of Filing Requirement:

Adjustments limited to twelve months immediately following the suspension period.

Response:

See Schedules D-2.15 through D-2.35 for adjustments to the forecast period.

Sponsoring Witness: William Don Wathen, Jr.

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(8)(c)

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807 KAR 5:001, SECTION 10(8)(c)

Description of Filing Requirement:

Capitalization and Net Investment Rate Base shall be based on a thirteen month average for the Forecasted Period.

Response:

Capitalization and Net Investment Rate Base for the Forecasted Period are based on a thirteen-month average.

Sponsoring Witness: William Don Wathen, Jr.

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(8)(d)

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807 KAR 5:001, SECTION 10(8)(d)

Description of Filing Requirement:

After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless such revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed. There shall be no revisions filed within thirty (30) days of a scheduled hearing on the rate application.

Response:

The Company will comply with this requirement.

Sponsoring Witness: William Don Wathen, Jr.

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(8)(e)

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807 KAR 5:001, SECTION 10(8)(e)

Description of Filing Requirement:

The Commission may require the utility to prepare an alternative forecast based on a reasonable number of changes in the variables, assumptions, and other factors used as the basis for the utility's forecast.

Response:

The Company will prepare an alternative forecast if requested by the Commission.

Sponsoring Witness: William Don Wathen, Jr.

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(8)(f)

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807 KAR 5:001, SECTION 10(8)(f)

Description of Filing Requirement:

The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.

Response:

See attached.

Rate Base exceeds capitalization by $33,828,759 for the forecasted period, which is a difference of 5.72%. One reason for the difference is that, per Commission precedent, the annualized depreciation adjustment is reflected as a rate base adjustment but is not included in the calculation of the electric rate base ratio. The remaining difference between the rate base and capitalization is also due to the fact that rate base is financed with certain balance sheet accounts, in addition to the sources of financing for capitalization, which consist of long-term debt, preferred equity, common equity, and capital made available in the form of accumulated deferred income taxes. This difference in sources of financing cannot be attributed to any one particular item.

To the extent that balance sheet accounts such as cash, accounts payable, taxes payable, *etc.*, have balances greater than zero, these items would finance a portion of rate base but would not be included in capitalization. Some of the difference between rate base and capitalization is attributable to these sources of capital which finance rate base (*e.g.*, cash, accounts payable, *etc.*) but which are not included in capitalization.

Sponsoring Witness: William Don Wathen, Jr.

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
RECONCILIATION OF CAPITALIZATION AND RATE BASE
AS OF DECEMBER 31, 2007

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).:

FR 10(8)(f)
PAGE 1 OF 1
WITNESS RESPONSIBLE:
W. D. WATHEN

Line No.	ASSETS	Electric Rate Base (Schedule B-1)	Electric Capitalization (Schedule J-1)	Other	Total ULH&P
		$	$	$	$
1	UTILITY PLANT:				
2	UTILITY PLANT IN SERVICE	1,127,085,000		348,994,267	1,476,079,267
3	LESS: ACCUMULATED PROVISION FOR DEPRECIATION	540,093,766		112,319,859	652,413,625
4	NET UTILITY PLANT	586,991,234	0	236,674,408	823,665,642
5					
6	OTHER PROPERTY AND INVESTMENTS				
7	NONUTILITY PROPERTY - NET			0	0
8	LESS: ACCUMULATED PROVISION FOR DEPR. & AMORT.			0	0
9	OTHER INVESTMENTS	0	0	3,491,585	3,491,585
10	SPECIAL FUNDS			0	0
11	TOTAL OTHER PROPERTY AND INVESTMENTS	0	0	3,491,585	3,491,585
12					
13	CURRENT AND ACCRUED ASSETS:				
14	CASH	13,962,791		1,817,395	15,780,186
15	SPECIAL DEPOSITS			0	0
16	WORKING FUNDS			0	0
17	TEMPORARY CASH INVESTMENTS			0	0
18	NOTES AND ACCOUNTS RECEIVABLE - NET			20,711,576	20,711,576
19	NOTES RECEIVABLE FROM ASSOCIATED COMPANIES			0	0
20	RECEIVABLES FROM ASSOCIATED COMPANIES			0	0
21	MATERIALS, SUPPLIES AND FUEL	17,341,822		5,609,938	22,951,760
22	EMISSION ALLOWANCES	5,919,968		(5,919,968)	0
23	GAS STORED - CURRENT.			8,407,070	8,407,070
24	PREPAYMENTS	6,699,569		1,185,481	7,885,050
25	MISCELLANEOUS CURRENT AND ACCRUED ASSETS			(8,232,405)	(8,232,405)
26	RENTS RECEIVABLE			0	0
27	TOTAL CURRENT AND ACCRUED ASSETS	43,924,150	0	23,579,087	67,503,237
28					
29	DEFERRED DEBITS:				
30	UNAMORTIZED DEBT EXPENSE			0	0
31	OTHER REGULATORY ASSETS	0		18,955,076	18,955,076
32	CLEARING ACCOUNTS			0	0
33	MISCELLANEOUS DEFERRED DEBITS			0	0
34	UNAMORTIZED LOSS ON REACQUIRED DEBT			0	0
35	ACCUMULATED DEFERRED INCOME TAXES			0	0
36	UNRECOVERED PURCHASED GAS COSTS			0	0
37	TOTAL DEFERRED DEBITS	0	0	18,955,076	18,955,076
38	TOTAL ASSETS AND OTHER DEBITS	630,915,384	0	282,700,156	913,615,540
39					
40	LIABILITIES				
41					
42	PROPRIETARY CAPITAL	0	286,140,760	59,252,562	345,393,322
43					
44	LONG TERM DEBT	0	223,518,365	40,705,526	264,223,891
45					
46	OTHER NONCURRENT LIABILITIES	0	33,587,210	(13,409,900)	20,177,310
47					
48	CURRENT AND ACCRUED LIABILITIES:				
49	NOTES PAYABLE		13,135,334	20,368,694	33,504,028
50	CURRENT PORTION OF LONG TERM DEBT			0	0
51	ACCOUNTS PAYABLE			65,629,360	65,629,360
52	NOTES PAYABLE TO ASSOCIATED COMPANIES			0	0
53	ACCOUNTS PAYABLE TO ASSOCIATED COMPANIES			0	0
54	CUSTOMER DEPOSITS			0	0
55	TAXES ACCRUED			18,951,698	18,951,698
56	INTEREST ACCRUED			4,500,646	4,500,646
57	TAX COLLECTIONS PAYABLE			(944,030)	(944,030)
58	MISCELLANEOUS CURRENT AND ACCRUED LIABILITIES			0	0
59	TOTAL CURRENT AND ACCRUED LIABILITIES	0	13,135,334	108,506,368	121,641,702
60					
61	DEFERRED CREDITS:				
62	CUSTOMER ADVANCES FOR CONSTRUCTION	0		0	0
63	ACCUMULATED DEFERRED INVESTMENT TAX CREDITS	0	699,033	6,242,111	6,941,144
64	OTHER DEFERRED CREDITS			7,345,690	7,345,690
65	OTHER REGULATORY LIABILITIES			11,767,489	11,767,489
66	ACCUMULATED DEFERRED INCOME TAXES	40,005,923		96,119,069	136,124,992
67	TOTAL DEFERRED CREDITS	40,005,923	699,033	121,474,359	162,179,315
68	TOTAL LIABILITIES AND OTHER CREDITS	40,005,923	557,080,702	316,528,915	913,615,540
69					
70	TOTAL	590,909,461	(557,080,702)	(33,828,759)	0

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(9)(a)

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807 KAR 5:001, SECTION 10(9)(a)

Description of Filing Requirement:

The prepared testimony of each witness the utility proposes to use to support its application which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.

Response:

All Testimony is provided under separate cover.

Sponsoring Witness: All Witnesses

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(9)(b)

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807 KAR 5:001, SECTION 10(9)(b)

Description of Filing Requirement:

The utility's most recent capital construction budget containing at minimum a three (3) year forecast of construction expenditures.

Response:

See attached.

Sponsoring Witness: Jim L. Stanley / John J. Roebel

Duke Energy Kentucky
Case No. 2006-00172
Capital Expenditures Budget
Years 2006-2008

Line No.	Project ID / Description	CWIP Balance @ 12/31/05	Projected Expenditures 2006	2007	2008
1	EB1152 - EBS FGD 08 LNDFIL CONC SPILWAY	$ -	$ -	$ -	$ 27,781
2	EB1412 - Cooling Tower Gear Box (2006)	-	97,979	-	-
3	EB1422 - Cooling Tower Gear Box 2007	-	-	100,322	-
4	EB1462 - Cooling Tower Fan Blades-2006	32,625	60,545	0	-
5	EB1472 - Cooling Tower Fan Blades-2007	-	-	61,995	0
6	EB1482 - Cooling Tower Fan Blades(2008)	-	-	-	63,176
7	EB1912 - EBS-2 Misc Valves	109,270	145,081	245,063	151,325
8	EB1922 - EBS-2 General Equipment	156,375	139,548	180,453	145,554
9	EB1942 - EBS Replace Rappers	200,219	762,014	-	-
10	EB200453 - Install Ash Pond Liner	-	-	509,893	484,494
11	EB200531 - Inst Thick Tunl Emer Sump Pump	-	5,937	6,289	6,659
12	EB200579 - Turbine Bearing Fire Suppress.	-	-	150,291	1
13	EB201218 - Cooling Tower Motor Replace-06	-	88,251	0	-
14	EB201219 - Cooling Tower Motor Replace-07	-	-	81,444	0
15	EB201220 - Cooling Tower Motor Replace-08	-	-	-	88,673
16	EB201221 - Repl pug mill dust collect 2-1	-	144,654	-	-
17	EB2012532 - 2 Ash Sluice Pump Motor Repl	-	525	557	89,415
18	EB201262 - Pulverizer Feed Chute	-	157,178	-	-
19	EB201267 - SO2 MONITOR REPLACEMENT	-	56,422	-	-
20	EB201268 - NOx MONITOR REPLACEMENT	-	-	56,976	-
21	EB201269 - CO2 MONITOR REPLACEMENT	-	-	-	59,508
22	EB201291 - Scrubber Upgrades	12,347,559	180,334	-	-
23	EB201292 - New East Bend Landfill	314,346	188,879	41,568	43,508
24	EB201293 - Upgrade 3500Hp FD Fan Motor	-	-	142,086	0
25	EB201294 - Install Lndfl Cell P-15 & P-16	139,525	4,611,059	22	-
26	EB201312 - Service Water Filters	-	297,011	-	-
27	EB201314 - Replace Precip Electrodes	-	-	960,841	5
28	EB201315 - Economizer Landing	-	35,457	-	-
29	EB201316 - Precip Key System	-	-	294,943	-
30	EB201318 - Replace B.A.H. Refractory	-	-	389,614	-
31	EB201319 - Replace Demin Acid Tank	-	29,804	-	-
32	EB201328 - Repl LPT L-2 Blading	-	324,171	1,390,322	-
33	EB201329 - Upgrade CEMS computer to XML	-	33,711	-	-
34	EB201331 - Replace Service Water Pump 2-2	-	-	-	242,038
35	EB201334 - Replace 2-1 Prec. In. Exp. Jnt	-	-	194,684	0
36	EB201337 - SAH Circumferential Seals	-	-	187,637	1
37	EB201341 - FGD Lab	-	-	-	30,231
38	EB201350 - C Conveyor Piping Replacement	-	48,057	-	-
39	EB201351 - Replace B Module Demister Trys	-	-	261,195	-
40	EB201353 - Replace Thickener Rake Arms	-	185,483	185,333	-
41	EB201356 - Demin Sump Piping Replace	-	-	-	99,732
42	EB201358 - Pulverizer Gbx Replace-2007	-	-	534,534	2
43	EB201359 - Pulverizer Gbx Replace-2008	-	-	-	541,561
44	EB201362 - Cooling Tower Gearbox 2008	-	-	-	51,957
45	EB201367 - CT Breaker Replacement-2008	-	-	-	65,187
46	EB201369 - Replace Ash Sluice Motor-2007	-	-	84,854	0
47	EB201370 - Install Stack Lining	-	36,615	877,246	-
48	EB201373 - WSP Discharge Conveyor Scale	-	24,597	-	-
49	EB201374 - DCS Evergreen Upgrade	-	327,152	-	-
50	EB201378 - WSP Capacity Enhancement	-	205,686	-	-
51	EB2542 - Foam Fire Protection System	-	-	-	441,690
52	EB2782 - FGD Landfill Conc Spillway 06	-	52,348	0	-
53	EB2922 - EB2-3rd Catalyst Bed-Addition	-	-	-	272,767
54	M5801200 - REPLACE SERV. BLD. HVAC RTU-4	-	7,038	-	-
55	M5801206 - Install Cathode Protection	-	-	31,934	0
56	M5801207 - Study for Cathodic Protection	-	5,462	0	-
57	M5801210- MF Ash Pond Rim Ditch	-	878	12,722	-
58	M5801212 - MF Service Bldg Ceiling Insula	-	460	-	-
59	M5801214 - Add Auto SW Sparging Valves	-	6,101	-	-
60	MCY01201 - Replace A-weightometer	-	-	7,036	0
61	MCY01206 - Replace CBU Var.DC MTR Drives	-	1,790	28,468	-
62	MCY01207 - MF CBU Feeder Bed Restraint	-	2,489	-	-
63	MF1236 - U6 INSTALL FGC SYSTEM	-	1,355,829	-	-
64	MF2098 - U6 Burner Front Fire Protect.	-	-	98,117	0
65	MF3058 - MFS-6 LNCFSII	455,246	3,876,634	-	-
66	MF3346 - Replace Sample Room Chiller	-	92,493	-	-
67	MF389 - CCY HEATING SYS RETURN LINE	-	16,639	-	-

Duke Energy Kentucky
Case No. 2006-00172
Capital Expenditures Budget
Years 2006-2008

Line No.	Project ID / Description	CWIP Balance @ 12/31/05	Projected Expenditures 2006	2007	2008
68	MF401C - Install Ground Water Well	-	22,481	0	-
69	MF4407 - MFS-CFCD General Equipment	1,057	8,466	17,334	8,830
70	MF441C - MFS 5&6 Misc Valves	33,811	93,475	63,795	162,496
71	MF442C - MFS 5&6 General Equipment	4,503	36,522	28,041	45,713
72	MF5506 - U6 PLC In Chem Sample Rm	-	106,648	-	-
73	MF600611 - MFS-6 REPL. COND. OUTLET VLV.	-	174,636	-	-
74	MF600962 - U6 Replace Airheater Baskets	-	-	-	586,555
75	MF600990 - Replace Boiler Rm Sump Pumps	-	101,880	-	-
76	MF601004 - U6 Replace Weightometer	-	79,571	0	-
77	MF601012 - REPLACE U6 SOOTBLOWER CONTROLS	-	419,976	-	-
78	MF601047 - U6 REPL MILL EXHAUSTER WHEELS	-	-	-	377,569
79	MF601060 - U6 Replace Heater Drain Pumps	4,246	97,051	-	-
80	MF601200 - Repl. SAH Racks & Pinion Gears	-	-	-	72,907
81	MF601201 - U6 Replace SW Strainer & ISO	-	-	15,252	126,878
82	MF601202 - U6 Ins Coal Bunker Air Cannons	-	-	-	372,116
83	MF601207 - Separate BWCP Seal Water Loop	-	560,158	298,737	-
84	MF601208 - Replace Unit 6 Igniters	-	505,140	-	-
85	MF601213 - SAH Gas Inlet Dampers	-	-	950,925	1,225,343
86	MF601216 - CONVEYOR "14" - REPLACE DRIVE	-	81,873	-	-
87	MF601219 - U6 LP/HP HEATER LEVEL CONTROLS	-	272,697	-	-
88	MF601223 - Replace O2 Control Unit	-	52,451	-	-
89	MFC00363 - SWITCHYARD LIGHTING IMPROVMNTS	-	28,404	-	-
90	MFC00989 - Replace Cribhouse Sump Pumps	-	12,663	0	-
91	MFC01205 - Repl Cribhouse Bucket Hoist	-	-	44,089	-
92	MFC01209 - Locker room HVAC replacement	-	-	-	25,226
93	MFC01210 - Low Pressure Compressor	-	44,426	1	-
94	MFC01212 - MFS-REPLACE TRAVELING SCREENS	-	64,926	-	-
95	MFC01213 - MFS-REPLACE TRAVELING SCREENS	-	-	66,467	-
96	MFC01214 - MFS-REPLACE TRAVELING SCREENS	-	-	-	67,722
97	MFC01216 - STUDY-316B INTAKE RULES	-	7,550	-	-
98	MFC01224 - MF Replace Locker Rm Roof	-	-	7,989	-
99	MFK00741 - MF Coal Conveyor H12	-	210,494	475,434	-
100	MFK01205 - CONVEYOR "11" - REPLACE DRIVE	-	104,435	-	-
101	MFK01206 - CONVEYOR "12" - REPLACE DRIVE	-	63,206	-	-
102	MFK01210 - REPLACE CONVEYOR "G" FEEDER	-	-	69,264	-
103	MFK01211 - REPLACE CONVEYOR "G" CRUSHER	-	-	169,826	-
104	MFK01214 - MFS U5 & U6 CEMS Upgrade	-	51,464	0	-
105	MFK01215 - Vent Fans unit 5&6 Tripper Rm	-	116,009	1	-
106	MFK01216 - Avian Systems Bird Relocation	-	26,355	0	-
107	WC301201 - WGC CT3 WASH DRAIN UPGRADE	-	33,892	-	-
108	WC501202 - WASH HEADER/DRAIN UPGRADE	-	33,892	-	-
109	WG0191 - WGS-CT1 Major "C" Overhaul #1	2,462,527	3,939,060	-	-
110	WG0244 - WGS-CT4 Major "C" Overhaul #1	(6,052)	-	2,748,667	14,616,905
111	WG047C - WGS General Equipment	2,367	24,837	25,426	25,906
112	WG048C - WGS Misc. Valves	-	48,439	49,588	50,524
113	WGS01202 - CT1-6 WDPF Controls Upgrade	-	-	-	576,392
114	WGS01204 - CT1-6 Egatrol Upgrade	-	-	-	395,733
115	WGS01205 - Security Camera System	-	43,232	-	-
116	WGS01206 - Black Start Controls Upgrade	-	129,845	-	-
117	WGS01208 - Cyber Security	-	16,215	343,881	56,811
118	WGS01210 - Sulfuric Acid Line Upgrade	-	10,710	-	-
119	WGS01211 - WGS CT1-6 Ctrl LAN Seperation	-	11,332	0	-
120	302C7679 - Empire- XFMR #3 Tran - 302C7679	-	-	24,678	56,493
121	302D7779 - Blackwell Sub-Inst 138-69 kV Tr - 3	148,428	1,745,512	677	-
122	302D7808 - Buffington-F6761 Relays - 302D7808	24,166	89,049	-	-
123	302E7903 - Dry Ridge-Inst Trans for new 10.5 -	1,848	21,053	55,282	-
124	302E7923 - Thomas More Inst Transmission - 302	25,569	33,103	-	-
125	303A7127 - Verona Substation Upgrd - 303A7127	587,169	167,765	-	-
126	303B7348 - Mt Zion 22.4MVA TB - 303B7348	659,387	545,161	-	-
127	303C7679 - Empire- Inst. XFMR #3 - 10.5mva - 3	-	-	152,092	448,653
128	303E7890 - Ft Mitchell Sub-Ret and remove - 30	-	85,248	0	-
129	303E7923 - Thomas More-Inst 22.4 MVA Tr - 303E	1,163,766	216,607	-	-
130	303ZANLG - Analog Circuit Replacement CP3 Dist	134,736	22,294	50,050	-
131	304C7678 - F6763 Empire Sub Loop - 304C7678	-	-	-	10,400
132	304C7709 - F6763 Empire ROW - 304C7709	-	79,714	-	-
133	304D7782 - F6761-Loop Through Ruark - 304D7782	17,462	75,607	-	-
134	304E7902 - F6761 Loop through Dry Ridge - 304E	-	-	61,183	-

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Years 2006-2008

Line No.	Project ID / Description	CWIP Balance @ 12/31/05	Projected Expenditures 2006	2007	2008
135	304E7924 - F966- Loop through Thomas More - 30	1,375	43,764	-	-
136	304F8346 - F6761 Loop through Verona - 304F834	11,512	180,684	-	-
137	310ZNB - ZULH&P NEW BUSINESS SOUTH AREA	-	4,975,959	5,094,011	5,144,598
138	312ZLL - ZULH&P LIGHTS SOUTH AREA	424,151	447,076	457,683	462,228
139	314B7344 - Mt Zion 41 & 42 Feeder Exits - 314B	29,492	151,459	-	-
140	314C7600 - Verona 41 Reconductor - 314C7600	242	100,115	-	-
141	314C7680 - Empire 43 - 314C7680	-	-	83,981	146,122
142	314C7731 - Verona North Reconductor - 314C7731	25,878	289,171	-	-
143	314E7905 - Hands 45- Reconductor - 314E7905	10,489	189,935	-	-
144	314E7906 - Dry Ridge 41 & 42 Feeder Exits - 31	-	-	35,381	-
145	314E7920 - Kenton 41 Extend-Orphanage Rd - 314	-	-	6,578	152,230
146	314E7921 - Richwood 42- Recond Mt Zion Rd - 31	10,064	364,960	-	-
147	314E7922 - Thomas More 41-42 Feeder Exits - 31	15,353	167,695	-	-
148	314F8344 - Verona 41 & 42 Feeder Exits - 314F8	1,340	190,722	-	-
149	314ZDA - ZULH&P DIST ASSESS SOUTH AREA	431	91,230	93,394	94,322
150	314ZLG - ZULH&P LG DIST IMPR SOUTH AREA	133,149	327,609	335,382	338,712
151	314ZRL - ZULH&P RL DIST IMPR SOUTH AREA	758,350	463,065	474,050	478,758
152	314ZUG - ZULHP UG CABLE RPLC SOUTH AREA	93,762	69,484	71,133	71,839
153	314ZUR - ZULH&P UR DIST IMPR SOUTH AREA	570,016	1,061,450	1,086,632	1,097,423
154	316ZBG - ZULH&P BLDGS/GRNDS SOUTH AREA	19,104	27,934	135,144	137,694
155	316ZGE - ZTOOLS ULH&P GEN EQUIP SOUTH	12,425	28,572	29,536	30,094
156	903G0504 - ULH&P MINOR DIST FAILURES	13,019	64,249	72,120	74,656
157	903G0534 - ULH&P MAJOR DIST FAILURES	170,142	34,554	38,787	40,151
158	903G7996 - ULHP DISTRIBUTION BATTERIES	-	9,076	10,187	10,545
159	906F0502 - ULH&P DISTR TRANSFORMERS	1,083,528	1,346,413	1,378,357	1,392,044
160	924G0500 - ULH&P ELECTRIC METERS	354,264	571,305	511,312	516,390
161	ISOD3ULH - ISO DAY 3 ULHP	-	45,474	4,939	-
162	NERC13BG - NERC 1300 CYBER SECURITY	-	61,870	157,646	105,927
163	NERC13XX - NERC 1300 SUBSTATION SECURITY	-	63,480	27,281	27,795
164	TOOL002 - TOOLS ULH&P TRANSPORTATION	1,632	70,858	5,907	1,204
165	TRLERULH - TRAILERS & CONST EQUIP ULH&P	-	21,420	21,630	21,630
166	U02Z7993 - ULHP MINOR TRANS SUB FAILURES	-	11,216	11,482	11,699
167	U03Z7688 - MISC DIST SUB NON-BUDGET WORK	-	102,718	115,302	119,357
168	U03Z7972 - MISC NON BUDGET CARRYOVER	-	53,597	62,880	68,913
169	U04ZGM - ZULH&P GOV MAND TRANS IMPR	85,362	215,813	220,933	227,186
170	U04ZUR - ZULH&P UPGR/REPL TRANS IMPR	34,307	54,103	55,386	56,954
171	U14Z7690 - MISC DIST LINE NON-BUDGET WORK	-	424,507	1,940,692	1,892,525
172	U14Z7973 - MISC NON BUDGET CARRYOVER	-	36,348	39,045	41,855
173	U14ZGLZ - ULH GLIT DISTRIBUTION	-	186,939	192,912	193,274
174	U14ZGM - ZULH&P GOV MAND DIST IMPR	853,578	1,267,274	1,297,340	1,310,223
175	U14ZKVZ - ULH&P DIST LINE CAPACITORS	162,256	369,360	378,123	381,878
176	U16ZMTRE - TOOLS ELEC MTR OPS ULHP	398	15,670	16,199	16,505
177	U24E8252 - AUTOMATED METER DISCONNECT ULH&P	-	-	116,876	0
178	ULHSTORM - ULH&P STORM BUDGET	111,667	170,740	174,790	176,526
179	X02U8310 - Buffington - Replace CB 682 - X02U8	-	-	172,859	1
180	X03U7988 - Wilder 138-13kV Transformer - X03U	-	1,098,974	258,556	-
181	ZU03HR07 - 803 BUDGET ADJUSTMENT 2007	-	-	982,037	4
182	ZU03HR08 - 803 BUDGET ADJUSTMENT 2008	-	-	-	1,303,893
183	ZU04VH07 - 804 BUDGET ADJUSTMENT 2007	-	-	379,703	1
184	ZU04VH08 - 804 BUDGET ADJUSTMENT 2008	-	-	-	391,331
185	AMS3 - SMALL WORLD UPGRADE TO 3-3	-	15,175	133,887	2
186	AVAYAUPG - EMAIL CHAT UPGRADE	-	20,576	-	-
187	AXIOM07 - UPGRADE AXIOM MOBILITY	-	-	132,710	1
188	AXIOM09 - UPGRADE AXIOM MOBILITY	-	-	-	-
189	BATMNT - BATGENMAINT	-	6,573	3,904	4,458
190	CAMWIRE - CAMPUS WIRELESS	-	14,832	0	-
191	CAORMUP - CAO RM upgrade	-	21,258	0	-
192	CINMAN - cincinnati MAN	-	15,595	19,821	26,664
193	CMSGEN - CMS General	-	113,021	96,689	2
194	COMCW05 - Common CW for 2005	-	9,168	53,289	1
195	DBR6 - SMLWORLD DESIGN BUILD REL 6	-	6,190	-	-
196	DBR7 - SMLWORLD DESIGN BLD REL 7	-	9,840	-	-
197	DBR8 - SMLWRLD DES BLD REL 8	-	-	-	18,742
198	DESBUILD - designated bldg replace sys	-	23,376	1,695	-
199	DM6 - upgrade from DM5 to DM6	-	5,388	-	-
200	DOCGEN - DOCUMENT GENERATION	-	7,674	-	-
201	DPSMIDWR - DPS/MIDDLEWAER LINK UPGRD	-	-	7,672	0

Duke Energy Kentucky
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Years 2006-2008

Line No.	Project ID / Description	CWIP Balance @ 12/31/05	Projected Expenditures 2006	2007	2008
202	EIPPPHA3 - EIPP PHASE 3	-	3,176	0	-
203	EMCUPG - EMC UPGRADE	-	-	24,735	1,972
204	ERRSP05 - res rate stabilization	-	9,751	-	-
205	FAXGATE - FAXING SOFTWARE FOR SUPPLY	-	2,643	0	-
206	IDENMOD - UPG mob data units	-	-	18,454	0
207	INFPRDSW - INFRASTRUCTURE SOFTWARE	-	16,339	-	-
208	IPCTURR - IPC TURRET UPGRADE	-	5,427	-	-
209	ITRON - replace Itron handhelds units	-	-	159,902	-
210	IVRPRO - IVR ports	-	-	14,302	-
211	IVRSPECH - speech recog integration IVR	-	-	48,708	-
212	JET2006 - UPGRADE TO JOB DESIGN TOOL	-	-	55,184	-
213	LEGATO47 - LEGATO4.7 UPGRADE	-	12,359	-	-
214	LOADRDPS - LOAD RESEARCH TIED TO DPS	-	-	16,947	0
215	MAXSUB - CIN-10 MAX INTRFC PASS &LDC	-	-	3,677	-
216	MDM - meter mgmt system	-	406,839	2	-
217	MITRA3 - MITRATECH INTERFACES	-	12,988	-	-
218	MKISUPGD - mkis upgrade	-	28,106	-	-
219	MOBDAT1 - MOB DATA INTERFACE	-	26,051	46,071	46,058
220	MTS - meter tracking system	-	52,820	-	-
221	MWREPL - microwave replacement	-	94,797	95,135	106,785
222	NOPAPER - NO PAPER	-	7,890	-	-
223	NTBBUPG - NETWORK BACKBONE UPGRADE	-	13,221	14,706	16,219
224	P3E2007- P3E ENH 2007	-	-	31,940	-
225	PASIBDUR - PASSPORT IBD UPGRADE	-	-	114,790	1
226	PHYNTSEC - PHYSICAL NETWORK SECURITY	-	9,090	14,941	7,267
227	RADBACK - radio backhaul	-	8,837	14,597	13,796
228	RADIOEST - RADIO REPLACEMNT PROGRAM EAST	-	763,726	6	-
229	RADIOS06 - RADIO REPLACEMENT PROGRAM	-	202,054	-	-
230	RFID - RADIO FREQ ID FOR PASSPORT	-	-	-	-
231	RFUPGRA - RF UPGRADE FOR PASSPORT	-	-	39,133	0
232	SASSERVR - SAS BI SERVER	-	14,923	-	-
233	SECEQUIP - Security Equipment	1,661	2,720	3,141	3,575
234	SMWEBSSE - SUMMATION WEB	-	6,423	-	-
235	SMWLDATA - SMALLWORLD DATA MIGRATION	-	3,171	0	-
236	STRCWIRE - structured wiring	-	12,152	33,831	26,308
237	STRNODES - structure nodes enh for sml wrld	9,256	4,005	-	-
238	SUBEXRV - SUBDIV EXCESS REVENUE SYS REPL	-	-	20,564	-
239	TCOM2005 - TROUBLE CALL UPGRADE	-	13,593	-	-
240	TCOM2008 - TCOMS UPG 2008	-	-	-	380,244
241	TELUPG - telephony upgrades	-	63,545	46,062	-
242	UMS1 - UMS IMPROVEMENTS	-	-	43,873	0
243	VENONRAM - VENDOR ON RAMP	-	3,176	0	-
244	VIRTHOLD - add virtual hold feature	-	-	11,065	-
245	VIRTUAL - CALL CENTER VIRTUAL ROUTING	-	18,721	-	-
246	VOIP - voice over IP	-	348	54,344	143,752
247	WANDIV - wan diversity	-	4,330	6,330	5,729
	TOTAL	$ 24,018,358	$ 41,878,561	$ 30,763,395	$ 39,552,505

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(9)(c)

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807 KAR 5:001, SECTION 10(9)(c)

Description of Filing Requirement:

A complete description, which may be filed in prefiled testimony form, of all factors used in preparing the utility's forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported

Response:

Attached is a copy of the Budget Guidelines for 2006 and a summary of the assumptions used in developing the projected data in the base and forecasted test periods. Descriptions of the forecast factors used in preparing the forecasted test period are also incorporated in each witness' pre-filed testimony.

Sponsoring Witness: Brian P. Davey

Assumptions
Forecasted Base Period Months (March 1, 2006- August 31, 2006)
Forecasted Test Period (January 1, 2007-December 31, 2007)

General Assumptions:

1. The base period consists of actual data for the six months ending February 28, 2006 and forecasted data for the six months ending August 31, 2006. The initial balances for the balance sheet portion of the forecasted six months of the base period were obtained from the February 28, 2006 balance sheet.

2. The Company's 2006 Annual Budget was used as the basis for the forecasted test period data, with certain adjustments as noted in the specific assumptions section below, following the Company's normal budgeting and forecasting guidelines to develop such adjustments (hereinafter referred to as "revised 2006 budget").

3. Available inputs from the Company's 2006 budgeting and forecasting process were also used for the forecasted test period data for this proceeding. To the extent that data was not available from the inputs from the Company's budgeting and forecasting process, the data described in section 2, above, was escalated as described in the specific assumptions section below.

Specific Assumptions:

1. Revenues

   a. The Company's Market Analysis Department prepares gas sales and electric load forecasts on a monthly basis for each customer class covering a ten-year period. These forecasts are based on ten-year weather normals. These forecasts were used to obtain the gas and electric operating revenues for the revised 2006 budget and for the forecasted test period, by applying the tariff charges to these forecast numbers for gas customers and for residential electric customers. The projected revenues for non-residential electric customers were calculated by using average realizations.

   b. The Company's revised 2006 budget and forecasted test period includes the merger credits approved by the Kentucky Public Service Commission's November 29, 2005 Order in Case No. 2005-00228 for the period beginning May 2006. The forecasted test period includes an assumed full recovery of fuel cost through a Fuel Adjustment Clause covering the period beginning January 1, 2007. No general electric rate case increase was assumed for the 2006 revised budget or for the forecasted test period.

c. Certain Other Operating Revenues for 2006 were obtained from the 2006 Annual Budget. The "other revenues" for periods after 2006 were obtained by using a 1.5% escalation, unless a better estimate was available. The revenues for the off-system sales for the 2006 revised budget and for the forecasted test period were based on an economic dispatch using the Company's Commercial Business Model, which uses projected market prices, production costs and generating availability, including an adjustment for the off-system sharing mechanism approved by the Commission in Case Nos. 2003-00252 and 2005-00228

2. Expenses

a. The fuel, purchased power, emission allowances and purchased gas expenses for the revised 2006 budget and the forecasted test period were obtained from the 2006 Annual Budget and adjusted as follows. The purchased gas expense for the revised 2006 budget and the forecasted test period was obtained from the Company's Gas Commercial Operations group as part of the 2006 budgeting and forecasting process. The Commercial Business Model was used to derive the fuel, purchased power and emission allowances expense by using the electric sales forecast from the Market Analysis Department, as updated with current market prices and fuel costs to model the least cost dispatch to meet the Company's native load requirements for 2007. The expense for the NOx emission allowances for the Commercial Business Model run was obtained by assuming that emission allowances would be required for a five-month summer period (covering the months of May through September) in 2006 and 2007 and that the vintage 2006 emission allowances that were unused at the end of 2006 were assigned a 50% tonnage value for use in 2007

b. The non-union labor expense from the 2006 Annual Budget was escalated by 4% to obtain the 2007 forecasted test period data. The escalation factor used for union labor expense for the forecasted test period data was 3.3%. Non-labor expenses were escalated by 1.5%, except as noted below.

c. The loadings rates used for the 2007 forecasted test period are the same loading rates used in the 2006 Annual Budget, as follows:

Fringe benefits	42%
Indirect labor	
Non-union	21%
Union	32%
Payroll taxes	7.5%

d. The regulatory assets were amortized according to the amortization schedules as approved by the Kentucky Public Service Commission's prior orders.

e. Transmission expenses for the revised 2006 budget and the forecasted test period were derived as follows. The Schedules 1 through 3 and Schedule 9 charges were obtained by applying the tariff rates to the electric load forecast. The charges for MISO Schedule 10-FERC, Schedules 10, 16 and 17 were derived by applying the Midwest ISO's projected charges to the electric load forecast. The transmission expenses for the remaining Midwest ISO Transmission and Energy Markets Tariff's revenues and charges was derived by using Duke Energy Ohio's historical information for the months of April 2005 through November 2005, and allocating these revenues and charges to Duke Energy Kentucky using Duke Energy Kentucky's load ratio.

f. Inter-company rent expense for the Duke Energy Ohio and Duke Energy Indiana headquarters and the Miami Fort 6 step-up transformer, typically not budgeted due to the inter-company relationship, were added for the revised 2006 budget and the forecasted test period.

g. The assignment and/or allocation of common expenses were obtained from the 2006 Annual Budget and were extended to the forecasted test period using the applicable labor and non labor escalation rates noted above.

h. The book and tax deprecation expense was obtained by applying composite depreciation rates (based on current applicable depreciation rates) to existing and new depreciable plant, based on the 2006 annual capital budget. The book and tax depreciation expense for the generating plants was obtained by using Duke Energy Ohio's depreciation rates for the plants in effect as of January 1, 2006, the effective date of the plant transfer. The newly leased Erlanger facility and the additional build-out construction project for that facility were added to the revised 2006 budget and the forecasted test period in calculating the book and tax depreciation expense.

i. The property tax expense and other taxes expense were obtained from the 2006 Annual Budget. The property tax expense for the forecasted test period was obtained by applying projected property tax rates to the most recent valuations as approved by the Kentucky Department of Revenue, as updated for projected additions, retirements, and additional depreciation. The property tax expense was projected on a calendar year basis and then levelized over the twelve months of the forecasted test period.

3. Income Taxes

   a. For the forecasted test period, the state and federal statutory income tax rates (5.8% and 35%, respectively) were used to determine the income tax expense.

4. Financing assumptions

   a. The short-term debt and investment rates range, on an annualized basis, from 4.7% to 4.9% for 2006 were obtained from the 2006 Annual Budget. For the forecasted test period, 5.5-5.8% annualized interest rates were used.

   b. The long term debt issued March 7, 2006 is included in the revised 2006 budget.

   c. The dividend levels used for the revised 2006 budget assume a 0% payout ratio on earnings for the 2006 calendar year and a 35.0% payout ratio for the forecasted period, consistent with the Company's objective for a balanced capital structure.

   d. The interest component of the capital leases for equipment was obtained from the lease agreements, and this amount was used for the revised 2006 budget and the forecasted test period.

5. Balance sheet assumptions

   a. The actual balance for the sale of accounts receivable balance was used as of February 28, 2006, and balance for the sale of accounts receivable for the revised 2006 budget and the forecasted test period was determined by assuming continuing sales of accounts receivable at the current maximum levels.

   b. The principal and interest payments for the capital lease payments were adjusted to include the December 2005 capital lease for newly leased meters and regulators and the Erlanger facility for the revised budget and forecasted test period.

c. The balances were updated to include the build-out construction project for the Erlanger facility for the revised 2006 budget and the forecasted test period.

d. The balances for the generating station coal, oil, gas, emission allowance and materials and supplies inventories were updated to reflect forecasted changes for the revised 2006 budget and the forecasted test period.

CINERGY®

2006
BUDGET
DEPARTMENTAL
GUIDELINES

August 2005

Table of Contents

1.0 General Guidelines for the 2006 Budget

1.1 General Guidelines

For the 2006 plan year, you are required to prepare a **1-year Departmental Expense Budget (2006)** - completed via the Responsibility Center (RC) Budget Tool & Employee Labor Budgeting Tool (ELB).

The Labor Pool will be downloaded on July 5th and will include all labor updates made to the HRIS database through June 30th. The various loading rates will be updated throughout the 2006 planning process. Please reference Appendix I for the current Plan Year Loading Rates.

The following tools are used for responsibility center budget development:

Employee Labor Budget (ELB) Tool

- Used to maintain your employee labor pools such as adding or deleting employees from your center; adding summer help, co-ops, etc.
- The ELB Tool is accessed from the BDMS Main Menu.
- Management Reporting
  - Provides a direct and fully-loaded dollar views as well as labor hours using excel pivot table capabilities
  - Head Count Report that shows the FTEs by organization (union, non-union, incremental, replacement, etc.)

Responsibility Center (RC) Budget Tool

- The available worked labor hours and losttime hours are passed from the ELB Tool to the RC Budget Tool.
- Used to enter the available worked hours across the code block elements. **Please note that you can only budget <u>hours</u> for labor in the RC Budget Tool, you cannot budget dollars.**
- Overtime can only be entered in hours.
- Also used to enter Non-labor dollars.

Responsibility Center (RC) Budget Reporting Tools

- **RC Budget Report Dashboard**
  - Used for budget input verification and to ensure data accuracy
  - Provides flexibility in analyzing data via Excel spreadsheet capabilities
  - Used primarily for your direct reporting requirements, but can be used with your fully loaded analysis and troubleshooting.
- **Hyperion Standard Reports**
  - Canned reports that provide drilldown capabilities
  - Used for labor utilization reporting
  - Used for fully loaded standard reporting
  - Used to view new Income Statement / Balance Sheet Standard Report and finalize budget

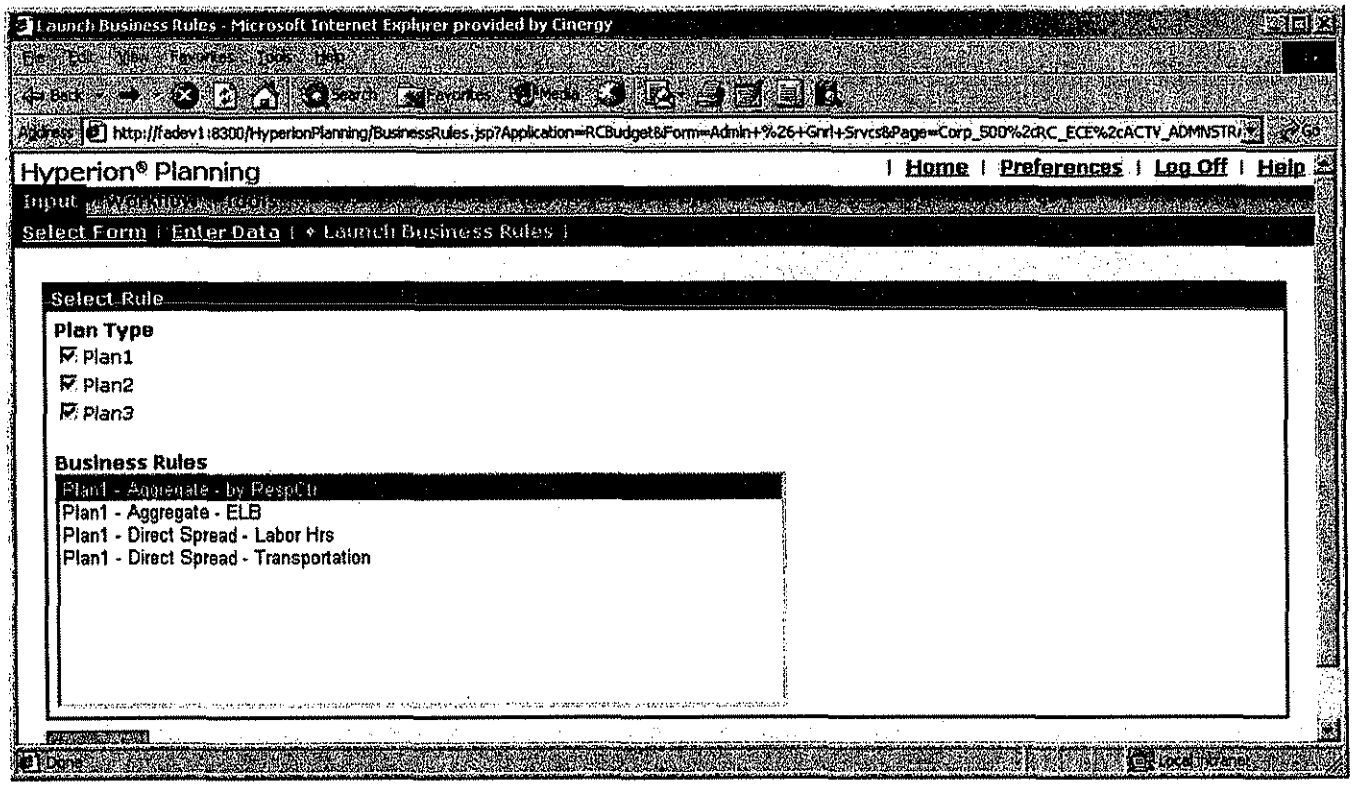
Available for reference is the Responsibility Center Budgeting User's Guide which includes instructions for using the Employee Labor Budgeting (ELB) tool and the Hyperion Planning RC Budget Tool. You can access the RC Budgeting User's Guide by going into IPower (opening Internet Explorer), click on "Communities" drop down list, click on "Finance & Accounting", click on sub-community "Budget & Forecasts". You'll find the "RC Budget User Guide" under "Reference Documents".

1.2 Significant Changes for 2006

- **Budgeting for 2006 Plan Year only.**
- **Zero-based budgets.**
- **Security will be administered by B&F– see Section 1.8 for process and Appendix VII for form.**
- **All vacancies will be added by B&F only with the exception of summer-help and co-ops – see Section 3.3 for process and Appendix VI for form.**
- **ELB will now load into the RC Budget Tool every 5 minutes; requires an aggregation to be performed (see ELB Budgeting section 3.1).**
- **Removal of the two year Business Rule for copy labor & non-labor function due to 1 year budget.**
- **STD (Short Term Disability) – budget as a cost pool item to accounts 184600 and 184610. STD is part of the indirect labor cost pool.**
- **Revenues will be entered as a negative dollar amount.**
- **Tool available between 6:00 a.m. and 9:00 p.m. daily.**
- **Reports on Direct and Fully Loaded views only; loaded views have been eliminated.**
- **2005 Budget data retained in ELB Management Reporting Tool only.**
- **Transportation Resources reduced from 38 to 7 and will budget in dollars instead of hours – see Section 4.6 for the new listing of transportation resources**
- **"Services" have been reduced (eliminated all the 'direct' service members).**

1.3 Budgeting Terminology

Launching Business Rules



What is a business rule?

- Logical expressions or formulas that are created within an application to produce a desired set of resulting values. What does this mean? Basically it automates certain functions (like spread labor dollars) that an end-user would want to perform.
- Also gives the users the ability to spread their labor hours and transportation dollars across the months based on available hours in a month.

The following is a definition for each of the business rules shown above:

- **Aggregate – by RespCtr** – Aggregation of data means that subtotals have been calculated and budget information is totaled in order for the user to begin analysis on the budget data. Once a user is done budgeting for the appropriate plan year, they need to aggregate their data; you can also use this Business Rule and aggregate at a summary center level. *(For example, a user may budget $5,000 to the resource 2432 – Contract Materials using the activity OSSER and another $5,000 to the activity STBLDGRN. Until the user aggregates the information, only $5,000 will total in the resource 2432 – Contract Materials. The user must launch the "Aggregate – by RespCtr" business rule before the true amount of $10,000 is reflected in the resource 2432 – Contract Materials.)*

  ****An overall Cinergy aggregation will occur once in the overnight processing.**

- **Aggregate - ELB** – once you have adjusted your labor pool in the ELB Tool and after the 5 minute interface from ELB to RC Budgeting Tool has occurred. Log into the RC Budget tool and run this aggregation, which will cause the labor utilization report to update the indirect labor hours as a result of the changes that were made in the ELB Tool.

- **Direct Spread – Labor Hrs** – When the user enters labor hours as a "Year Total" the system will spread the hours across the months using a designated percentage (i.e. the percentage of hours available to be worked in that particular month).

- ***Direct Spread – Transportation*** – will spread transportation dollars across the months using the same designated percentage as direct labor hours (see above). Running this business rule is optional. If you opt not to run it, and you budget a 'total' dollar amount, your transportation dollars will spread evenly in each month.

Please reference section 4.1 of the RC Budgeting User's Guide for more information on business rules.

Hyperion Essbase

All Hyperion tools are a front-end to a database called "Essbase" which stores and retrieves data. For example, Hyperion Planning serves as a mechanism for users to enter data that is sent to the Essbase database. Essbase is a multidimensional database software product that supports multiple views of data sets for users who need to analyze the relationships between data categories (i.e. budgeting across the code block elements). In Essbase, the code block elements are referred to as **"dimensions"** which contain an unlimited number of **"members"**. For example, Activity is a dimension and ADMNSTRA is a member within the Activity dimension.

Hyperion Essbase Spreadsheet Add-In is a software program that merges seamlessly with Microsoft Excel. Software will be installed on the end-user's computer to allow them to access their budget data housed in Essbase via Microsoft Excel directly. This is what we call the RC Budget Report Dashboard. See the User guide section to find out how to have Hyperion Essbase Spreadsheet Add-in loaded on your PC.

Direct and Fully Loaded

Please reference Appendix II for an example of the difference between direct and fully loaded reporting.

Definitions

- Direct – Dollars as they were input into the RC Budgeting tool without any loadings.
- Fully Loaded – All labor loadings, LOB allocations and cost assignment allocations have occurred in the fully loaded view.

1.4 Financial Coordinator List

If you have a question that is not answered in these guidelines, please call your Financial Coordinator:

Commercial Business Unit:	Todd Lovegrove	419-5145
	Tonia Murphy	419-5310
	Yelena Neizvestny	419-5827
	Keith Baldwin	419-5016
Regulated Businesses:	Lisa Steinkuhl	287-2254
	Diane Kittrell	287-2571
	Jacqueline McGhee	287-2710
	Ann Harley	287-2700
	Brian Price	287-3248
	Dave Schafer	287-2822
Power Technology & Infrastructure Services:	Chad Ream	287-2605
Corporate Center:	Jon Kelly	287-1066
	Rebecca Kreissl	287-5771
	Dawn Merritt	287-2738
	Jennifer Mulligan	287-2041
	Doug Schwerman	287-3865

Shared Services

Jacqueline Calloway 287-2857
- Administrative Services (DAS) – Brian Vance
- Corporate Communications (157) – Joe Hale
- CIN-10 Initiative (155) – Craig Weida

Brian Callahan 287-1341
- Human Resources (HR1) – Tim Verhagen
- Labor Management (HSS) – Caryn Riggs

Allison Heckel (or Jacqueline Calloway) 287-3317
- Accounts Payable – Lisa Carver
- Payroll – Lisa Carver

Christina Johnson 287-1993
- IT Opers & Management Expenses (IT1) – Bennett Gaines
- Incentive Compensation (069) – Karen Feld

Barb Zupan 838-1126
- IT Capital Projects (ICR) – Bennett Gaines

Dennis Sunberg 287-5676
- SSFO Manager

1.5 Key Planning Dates

Date	Description
July 1	Preliminary Joint Owner Exchange
July 5	HRIS Labor Pool Download into ELB reflecting employee headcount through June 30th.
July 11	ELB Tool opened for input
July 11 – Aug 3	BU's work labor pools in ELB; also identifying any vacancies by completing proper form and approvals.
July 14 – Aug 5	ELB and RC Budget Tool Training
July 25	RC Budget Tool opened to coordinators to allow time to update Input Forms and make any other needed changes
August 1	**RC Tool opened for input**
August 3	VP / President approved vacancy forms sent to B&F
August 8	B&F has all approved vacancies entered into ELB Tool
August 10	Final approval of vacancies by Jim Rogers
August 17	Gibson Unit 5 exchange
September 1	CD/CCD Joint owner budget exchanges
September 2	**Budgeting Systems Closed - Preliminary**
September 19	RC Budget Tool Reopens
September 26	**RC Budget Tool Closed – Final**
Sept 28 – 30	Board Retreat
October 10 – 11	Preliminary BU CFO Review Meetings (CBU, RBU, CC and SS)
Nov 1 – 4	Final BU CFO Review Meetings (CBU, RBU, CC and SS)
November 9	Budget Review with Turner
November 16	Budget Review with Rogers
November 18	**Budget Final**
December 15	Board Meeting – Budget Approved

1.6 Budget Development

Below is an outline of the steps to follow when preparing & entering your budget.

Day 1

1. Access IPower and under the Communities menu, click on Finance and Accounting and click the Budget & Forecasts sub-community. Within the Budget & Forecasts community, upper left corner, click the BDMS Main Menu to access ELB. When you've accessed ELB, set up the center's defaults for Corporation and Line of Business (LOB). These defaults are used to establish the center's indirect labor.
2. Select Adjust Labor Pool button and make any necessary changes for each labor class
3. Run Head-Count report to verify FTEs
4. *Interface between ELB and RC Budget Tool will run every 5 minutes*
5. Access the RC Budget Tool via IPower. Under the Communities menu click on Finance and Accounting and click the Budget and Forecasts sub-community. Click on the RC Budget tool link in the top left corner.
6. Launch Aggregate ELB business rule.
7. Run the Labor Utilization Report for your RC and verify the remaining hours that need to be budgeted (this is the difference between available hours and the indirect labor cost pool (vacation, holidays, etc.) hours).
8. Open your budget input form in Hyperion Planning.
9. Select code block intersections for budgeting (i.e. activity, account, LOB, etc.)
10. Budget remaining labor hours based on the labor utilization report and input the non-labor dollars
11. Launch business rule Direct Spread – Labor Hours.
12. Launch business rule Aggregate – by RespCtr
13. Rerun the Labor Utilization Report to ensure all labor hours were budgeted (remaining labor hours for year total should be zero); if not go back to step 8
14. Access IPower. Under the Communities menu click on Finance and Accounting and click the Budget and Forecasts sub-community. Click on the RC Budget Reports Dashboard link in the top left corner.
15. Log into the RC Budget Reports Dashboard to view the RC Budget Detail Reports
16. Run a direct RC Budget Detail Report to verify accurate input of labor hours and dollars; if needed, go back to step 8 and make changes
17. Wait overnight to access fully loaded data.

Day 2

18. Access IPower. Under the Communities menu click on Finance and Accounting and click the Budget and Forecasts sub-community. Click on the RC Budget tool link in the top left corner.
19. Log into RC Budget Tool and access Hyperion Standard Reports
20. Run the Financial Statement View report; if further analysis is not needed skip to step 25
21. Access IPower. Under the Communities menu click on Finance and Accounting and click the Budget and Forecasts sub-community. Click on the RC Budget Reports Dashboard link in the top left corner.
22. Log into the RC Budget Reports Dashboard to view RC Budget Detail Reports
23. Run Fully-Loaded RC Budget Detail Reports
24. If changes are needed to fully loaded labor hours and/or dollars return to step 8 of day 1
25. Submit budget for approval
26. Repeat until budget is approved / finalized

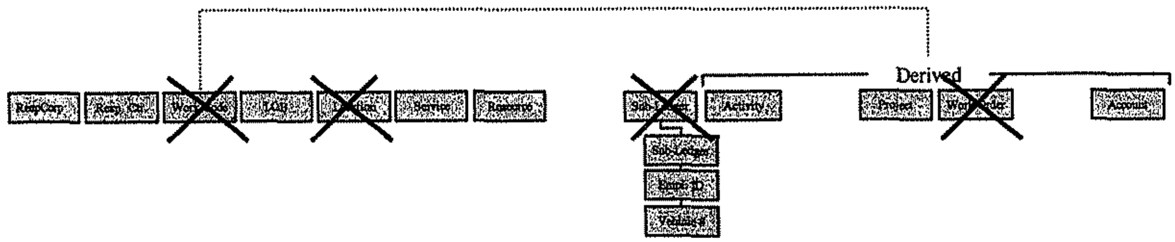
1.7 ELB / RC Budget Tool Security Process

Due to Sarbanes Oxley requirements, a form has been developed to gain security to either the ELB Budget tool or the RC Budget tool. (See Appendix VII for form or print a hard copy available on the Budget and Forecasts sub-community from the Finance & Accounting Reference Documents). Here are some general rules for filling out the form:

1. This form is to be used for detail and summary centers.
2. If you need access to all detail centers that roll to a summary center only fill out a form for the summary center.
3. If you need security to multiple detail or summary centers that have different rollup security levels, please fill in a separate column for each.
4. The security approval process is as follows:
    - Any level of access must be approved by the user's manager.
    - If Manager approves, form is sent to your BU Financial Coordinator.
    - Access to salary information and/or visibility to view budget data for a BU or Consolidated requires additional approval by the BU CFO.
    - BU Financial Coordinator sends approved form to Budgets & Forecast
    - All security updates will be performed by B&F.

2.0 Code Block Requirements

2.1 Code Block Overview



<u>The following code block elements are used in the budget process:</u>

- Resp corp
- Resp Ctr
- LOB
- Service - all indirect services have been eliminated. Used by CC and SS centers ONLY
- Resources
- Activity
- Project – optional for O&M budgeting – (other than NOPROJ)
- Account

2.2 Adding New Code Block Elements

The following BDMS 3.0 tables will be passed nightly to the RC Tool.

- Corporation
- Centers *
- Activities
- Projects *
- Accounts *
- Line of Business (LOB)

* Have a 'Pass to HP' flag in BDMS 3.0 which limits the members to be passed to the budget tools.

The following tables will be manually maintained in the RC Tool with <u>no</u> feeds from BDMS 3.0 tables.

- Services
- Resources

Any request for new Service or Resource values should be sent to #RC Budget Tool Owners.

3.0 Employee Labor Budgeting (ELB) Tool

3.1 Enhancements to ELB for 2006 Plan Year

In Center Setup – You not only select your default LOB but you have the option to pick a Corporation other than the default. Interface between ELB and the RC Budget Tool will run every 5 minutes.

3.2 Setup Center Defaults

The ELB Tool automatically calculates the indirect labor hours for a center based on the number of vacation, holiday, and personal days entered into the ELB labor pool screens. Indirect labor is the total number of losttime (non-worked) hours for a center. It's the hours not available to be worked. Based on the total number of indirect labor hours and the center's average hourly rate for each employee class, the ELB Tool will pass the indirect labor dollars to the RC Budget Tool.

Each center is required to have a default LOB and corporation that will be charged for these indirect labor dollars. The guidelines are as follows:

- If you are a Corp 500 or 010 employee you are required to use LOB ALP for indirect labor.
- If you are a Corp 070 or 100 employee it is recommended that you use the ALP LOB for indirect labor, however, you may use any applicable LOB.
- If you are an employee of any other corp you are required to use the LOB associated with that corporation. (For further direction, please contact your Financial Coordinator).

3.3 Adjust Labor Pool

All labor information will be downloaded into the ELB tool from the Human Resources Information System (HRIS) on July 5th. This download will include all updates to the HRIS database through June 30th. Each center's Labor Pool is divided into three resources; exempt, non-exempt, and union. The purpose is to identify all internal resources needed for the current Plan. Contractor Resources are not in this section (see Contracts in Section 4.3).

The following vacancy positions will be required to go through a formal approval process. Centers will not have access to enter these vacancies into their budgets. All input will be completed by B&F after final approvals are submitted.

- **Replacement** – a position that is added to replace an employee that is no longer with Cinergy. The employee has not been hired yet and will not increase Cinergy's headcount.
- **Replacement Hired** – an employee that is added because they have already been hired in 2005 to replace an employee that is no longer with Cinergy. This is not an increase to Cinergy's headcount. The employee name is required to be entered.
- **Incremental** – employees that have not been hired yet and are going to be an addition to Cinergy's headcount.
- **Incremental Hired** – Employees who have already been hired in 2005 and will be an addition to Cinergy's headcount. The employee name is required to be entered.
- **CIN10 Staff Addition** – positions that have been approved as part of the CIN10 initiative. These are increases to the centers headcount.
- **CIN10 Staff Reduction** –positions that have been identified as headcount to be cut due to the CIN10 initiative.

Please reference section 2.2.2 of the RC Budgeting User's Guide for a complete listing of the "organizations" available. If you have questions regarding these organizations please contact your BU Coordinator.

Listings showing CIN10 additions and deletions, by center, will be provided from the CIN10 group. These listings will be reviewed by the BU Financial Operation groups. The BU Financial groups will provide these listings to each center owner who will be responsible for adding to their vacancy request forms.

June 30 – all employees within the HRIS system will be loaded into the budget system (ELB Tool). B&F will ensure that this load ties to the HR employee census reports shown on IPower.

July 11 – the ELB Tool will be placed into production.

August 3 – BU's will have consolidated review and summary of all vacancies completed and approved by the appropriate President / Vice President. Final approved listings will be sent to B&F for input.

- RBU – John Procario / Greg Ficke / Kay Pashos
- CBU – Michael Cyrus
- PTIS – Greg Wolf
- SS – Fred Newton
- CC Finance – Jim Turner
- CC Legal – Marc Manly
- CC Procurement – Ron Reising
- CC Global Risk – Ted Murphy

August 8 – B&F will have all vacancies entered into the ELB Tool.
Note: If approvals are received by July 27th, B&F will have vacancies entered into the ELB Tool by August 1st.

August 10th (1:00 – 2:30) – Meeting with Jim Rogers. Jim's direct reports will present their vacancy requests with explanations and justifications. Final approval from Jim is required for vacancies to be entered in to the budget system.

NOTE: Anyone seeking vacancy approvals after this meeting will need to coordinate getting Jim's signature independently. If you need assistance with this process, please contact Tim Verhagen.

The **Vacancy Request Form** can be accessed via the IPower Web at Communities / Accounting & Finance / Budget & Forecasts/ Reference Documents. See Appendix VI for a copy of the vacancy request form.

Note: When adding any vacancy the stop date of 209912 should be used in the employee labor pool detail screen, unless the applicable date is known.

Centers will still have security to enter:

- **Summer Help** – Typically high school students that work during the summer months only.
- **Co-ops** – College students that work 3 months then return to school for 3 months throughout the year.
- **Other Adjustments** – Lump sum dollar amount that affects salaries (i.e. one-time salary adjustment for merit increase)
- **Shared Resources** - (i.e., borrowed/loaned employees). The number of FTEs, and their beginning and end dates is information that is required for budgeting shared resources.
- **Staff Reductions** - Any staff reductions. The beginning date is required for budgeting staff reductions. To ensure the appropriate employee headcount and labor dollars for part time employees, each Full Time Equivalent (FTE) will be budgeted as 1 and their salary at 100%; then reduced 1 FTE by using the Staff Reduction organization. **Only use Staff Reductions or Other Adjustments for items that will affect the entire center labor pool.**

Other considerations when updating your labor pools include:

- The ELB tool will automatically calculate annual labor increases. The labor rate increase for each type of labor will be input by your BU coordinator. The planned labor increase for Union employees will be based on their contract agreement. The rate **3.8%** is assumed for non-union employees is for planning purposes only and is not meant to be interpreted as the labor rate increase for 2006.
- Please be sure to enter the 40 hours pre-paid sick for the applicable unions in your employee labor pool.
- Please be sure to un-claim any employees that will not be part of your responsibility center 1/1/06 or after.

Your labor dollar pool will need to be adjusted for the total amount of merit increases, promotions, and shift differential. The following is a list of examples that may necessitate an adjustment to your Labor Pool or Budgeted Labor Hours:

- Anticipated Promotions
- Special Lump Sum Bonuses
- Shift/Sunday Premium for Union Work
- Additional $350 per month for Exempt Shift Worker
- Holiday Premium Overtime Pay
- Guaranteed Holiday Pay
- 12Hours Shift Schedules

Please contact your Financial Coordinator for assistance in budgeting these items.

Based on the information you input into the RC Budget Labor Pools, an average hourly rate per month for each employee labor class is calculated. See Appendix III for an example of how the monthly average hourly rate is calculated.

Vacation / Holiday / Other Personal Day Entitlements:

The labor pools are automatically populated with the proper number of days for holiday, vacation, personal days, diversity days, and floaters for every employee. Appendix IV shows the allotted number of days for exempt, non-exempt, and each union. Any exceptions should be manually entered into ELB. Please be sure to decrease your labor pool for any vacation bank time you are aware that employees may take. You can reference the latest vacation, holiday, and other time off entitlements under the Human Resources IPeople website also.

4.0 Budget Entry / Planning by Resource

4.1 Labor

To reiterate, all labor information will be downloaded into the ELB tool from the Human Resources Information System (HRIS) on July 5th and includes all labor updates made to the HRIS database through June 30th. After updating all information in your Labor Pools, run your labor utilization report to determine the number of available hours to be budgeted for each employee labor class. Only internal Cinergy labor should be budgeted to the labor resource.

All labor will be budgeted by hours, not dollars. The dollars will be calculated based on the number of hours entered and the average hourly rate for each center / employee labor class. Labor, the majority of the time, should be budgeted to the activity **ADMNSTRA.**

Labor can also be adjusted for overtime. Overtime can only be entered through the budget entry screen in the RC Budget tool. Overtime will be spread based on the hours available to be worked in the month.

1111 – Labor Exempt
1121 – Over time Labor – Exempt
1112 – Labor – Non-Exempt
1122 – Overtime Labor – Non-Exempt
1113 – Labor – Union
1123 – Overtime Labor – Union

1131 – Special Pay – Other – Special pays that include tuition reimbursement, non-exempt and union overtime meals, executive car allowances, etc.
1132 – Special Pay – Sal&Wag – Special pays to be included in Salaries & Wages reports such as incentive compensation payments.

4.2 Company Materials

2111 Stock Materials – Material that has a catalog ID in Passport. Material purchases are to be budgeted to the **Stock Materials resource (2111)** regardless of whether or not they will be issued from a company storeroom or directly delivered to the job site. SF&H and minor material loadings are applied to stock material purchases (excluding CBU).

2112 Non-stock material – Materials that are acquired for work which are not stocked in the Cinergy Inventory System (no catalog ID). SF&H loadings are applied to non-stock material purchases (excluding CBU). Minor material loadings are <u>not</u> applied.

4.3 Contracts

2431 Contract Labor - is work that is being outsourced. Examples include tree trimming, programmers, DSM inspections, and station maintenance work. Contractor labor does not include research results (EPRI), EEI dues, or lobbying time for IEA. Contractor work can be seasonal, specialized and/or infrequent. Contractor work is typically budgeted directly to the client company (i.e. Corp 010 for a contractor engineer hired to do project work for CG&E) and NOT budgeted to Corp 500 (Service Company). Please do not budget in the contractor resource costs for services that are required to meet external requirements and cannot be performed by company employees due to independence, agreement or ordered requirements (i.e., D&T financial audit); these costs are to be budgeted in the 2411 - Outside Service resource. If you are not certain whether to budget costs to Contractor Labor or Outside Services, please call your Financial Coordinator.

<u>**IMPORTANT NOTE:**</u> Consulting Services are considered to be an "Outside Service" and are to be budgeted in the 2411 - Outside Service resource.

2432 Contract Material - is material that is delivered by a vendor to the contractor for the contractor's use. The company reimburses the contractor for the material. Contractor Material purchases are to be budgeted to the 2432 - Contract Material resource and to the specific client company (i.e. Corp 010 for material purchased for a CG&E project).

4.4 Payables

2411 - Outside Service – Outside Service is work performed by contractors or external resources that cannot be performed by Cinergy employees due to independence, agreement, or ordered requirements (i.e., D&T financial audit). **Budget to the OSSER activity.**

<u>IMPORTANT NOTE:</u> If you are planning to budget outside legal services, please contact Terri Haussin in the Legal department before entering your dollars. Generally, all outside legal services are budgeted by the Legal Department. In order for Legal to accomplish their CIN-10 targets, all legal services should be discussed and approved through Legal.

2412 - Political Contributions* – Contributions made to a *political committee or citizen group*

2413 - Business Meals* – Includes costs for any business meals (breakfast, lunch, or dinner) including gratuities, or entertainment for employees and their guests.

2414 - Employee Expenses* – Includes expenses such as travel costs, personal car mileage, and lodging.

2415 - Payables – Other - The primary resource used when budgeting assorted expenses such as office supplies, computer costs, vehicle expenses, general expenses such as membership dues, event tickets, advertising, etc. These are examples and are not considered to be an inclusive list.

*Resource codes 2412, 2413, and 2414 above are not required for budgeting purposes, but are available if the user would like to see actual vs. budget reports at this level of detail.

4.5 Other

2421 – Journal Entries & Other – This resource code is used for miscellaneous dollars that do not fit with any other resource code. It is the default resource code within the journal entry tool. Amortizations would be budgeted to this resource.

2422 – Journal Entries – No Constr OH - *This resource should not have any budgeted dollars.* This is used by Fixed Asset Accounting for closing out work orders.

2423 – Salvage – This resource should not have any budgeted dollars. Used when recording salvage related charges.

2424 – Non-Cash Items - This resource should not have any budgeted dollars. This resource is used by Fixed Asset Accounting.

4.6 Transportation (excluding Commercial Business Unit)

- **Transportation Usage**

Transportation will be entered in dollars, not hours, for the 2006 budget. Please notice that not all transportation resources will be used for budgeting; only the 7 classes shaded below. (Please refer to the Transportation Services web page (http://web/transportation/fleet.htm) for the most up to date Vehicle Class Loading Rates and Descriptions.)

New Transportation Resource Hierarchy

- 2600 - Transportation
  - 2601 - Class 1 Sedans
    - 2611 - 1A Basic Sedan (Non-commuting)
    - 2612 - 1B Basic Sedan (Commuting)
    - 2613 - 1C Executive Class Sedan
    - 2619 - 1D Luxury Executive Class Sedan
  - 2602 - Class 2 SUVs
    - 2614 - 2A Base SUV (Non-commuting)
    - 2615 - 2B Base SUV (Commuting)
    - 2616 - 2C Exec. Class SUV
  - 2603 - Class 3 Vans
    - 2617 - 3A Mini Van
    - 2618 - 3B Full-Size Van
  - 2604 - Class 4 Pickup Trucks
    - 2631 - 4A Compact PU 4x2 (Non-commut)
    - 2632 - 4B Compact PU 4x4 (Non-commut)
    - 2633 - 4C Compact PU (Commuting)
    - 2634 - 4D Full - PU 4x2 (Non-commut)
    - 2635 - 4E Full - PU 4x4 (Non-commut)
    - 2636 - 4F Full - PU (Commuting)
    - 2637 - 4G Full - PU 4x2 (Commuting)
  - 2605 - Class 5 Utility Trucks and Other Equip
    - 2651 - 5A Utility Body 4x2 Under 1 Ton
    - 2652 - 5B Utility Body - Heavy Duty
    - 2653 - 5C HD Util 4x4;Tract;Dump;Svc
    - 2654 - 5D Stake w/Mtd Derr;Trk Tract
    - 2655.- 5E Bucket Truck 4x2 (Over 40')
    - 2656 - 5F Mtl Handler/Line Trks 4x2
    - 2657 - 5G Mtl Hndlr Bkts 6x4/Line Trk
    - 2660 - 5H Util Body 4x4 under 1 ton (Non Com)
    - 2661 - 5I Util Body 4x2 under 1 ton (Com)
    - 2662 - 5J Utility Body 4x4 under 1 ton (Com)
    - 2664 - 5X HD Util 4x4 Tractors; Hd Dump Trucks - PSI
    - 2665 - 5Y Material Handlers/Line Trucks 4x2 - PSI
    - 2663 - 5R Rental Bucket and Derric Trks
  - 2606 - Class 6 Step Vans
    - 2658 - 6A Step Vans
    - 2659 - 6B Step Vans w/mounted equip
  - 2607 - Class 7 Heavy Equipment
    - 2671 - 7A Puller/tensioners
    - 2672 - 7B Sweep;Frklft;Bkhoe;Trnch
    - 2673 - 7C HD Construction Equipment
    - 2674 - 7D High Expense Constr Equip
    - 2675 - 7E Very High Exp Constr Equip
    - 2677 - 7F Low Expense Constr Equip
    - 2676 - 9 Trailers & Misc Other Veh

Budgeting:
Budgeting will be performed at the first resource under the new summary levels:
2611
2614
2617
2631
2651
2658
2671
Therefore, an amount will be entered at 2611 that represents the budgeted dollars for the 2611, 2612, 2613, and 2619 vehicle classes.

Variance Reporting:
Actuals will continue to be charged at all detail level resources (total of 38).
Variance reporting will be performed at the summary levels:
2601
2602
2603
2604
2605
2606
2607

Recommended approach when budgeting for existing vehicles:

Review actual transportation dollars that have been charged to your center. Reviewing this information will help determine the dollar amounts to be budgeted to the seven different transportation categories. A review of the 2005 budgeted transportation dollars will also help validate the reasonableness of your estimates.

If additional vehicles need to be budgeted for 2006 please refer to the annual dollar amounts by budgeted vehicle class to determine the appropriate dollar amount to budgeted (See Appendix VIII).

- **Executive Vehicles**

Executives will participate in the car allowance program that provides a monthly cash spend intended to take care of all vehicle related costs, such as lease payment, gasoline and insurance. When budgeting for executive car allowance please use the **Activity "CARALLOW".** If you have a question regarding a specific executive's situation or allowance, please contact Lisa Gregory, Manager Executive Compensation at 287-3934.

If you do not participate in the Car Allowance program but have your vehicle leased through the Wheels program please budget those dollars to the **Activity "WHEELSEC"**. If you have questions regarding the Wheels Program please contact Ronnie Benzing at 287-1164.

- **Helicopter Usage**

Helicopter expense is budgeted by dollar amount. Please use the rate of $1,000 per hour in your calculation.

5.0 Human Resources

5.1 Redeployment Pool

A central budget within HR will be established for redeployment. This centralized budget will be used to account for labor once an employee is assigned to redeployment. If you foresee that employees who are currently in your budget may be assigned to redeployment, continue to budget them under your department through their release date to redeployment. Human Resources will budget the employee from the release date until the time the employee is redeployed into a full-time position elsewhere. Human Resources will also budget for non-labor expenses related to redeployment.

- If you are filling a budgeted vacancy with a redeployed employee, continue to budget as you normally would for that position. Human Resources will prepare a calculation to determine if there is any excess labor expense. If there is an excess labor expense, this expense will be budgeted in the centralized redeployment budget for an agreed upon period of time. It is our goal not to double-budget labor expense.

Nicha Flick, the pool administrator, will need to know who is being assigned to redeployment and approximately when that will happen. Please contact Nicha at 513-287-4404 with names and/or numbers of employees being assigned to redeployment so she may budget accordingly. Also, contact Nicha if you need specific information about redeployed employees.

5.2 Navigator MBA Rotational Program

HR will budget the labor for the Navigator program in 2006. However, if a Navigator is currently assigned to your area or if you anticipate having one work in your area next year, you should budget for the associated expenses in your responsibility center budget. This would include items such as PC's, cell phones, subscriptions, etc. The Navigator program will continue to be administered through Deborah Battista. If you have any questions, including the availability of Navigator employees, timing of rotational assignments, or costs of the program, please contact Deborah Battista at 513-287-2809.

5.3 Business Unit Incentive Plans

HR Compensation & Benefits will budget for all CBU, RBU, PTIS, Corporate Center and Shared Services employees eligible for the AIP and UEIP incentive plans. HR Compensation & Benefits will also budget for the LTIP and stock option expenses. Business Units should only budget incentive plan dollars for any specific plan payouts that would be in addition to the CBU, RBU, PTIS, Shared Services or Corporate Center AIP and UEIP plans.

The incentive plans should be based on a corporate level 2 achievement.

5.4 Executive (GM and above) Benefits

On 1/1/05, Cinergy changed its administration of the executive benefits. Each executive will be paid a lump sum to compensate them for the value of their executive benefits in the month of January. This lump sum allowance will not include reimbursement for car allowance. This amount will be grossed up for taxes based on the state in which they reside. Each center will be responsible for the lump sum amount plus the FICA taxes from a budgeting standpoint.

Please budget in the month of **January** to the **Resource "Special Pay - Other"** and the **Activity "BENADMIN"**. Please call Damon Porter at 287-2432 if you have questions regarding the specific dollar amounts that will need to be budgeted for your center.

6.0 Facility and Other Misc. Equipment / Service Expenses

6.1 Facility Costs

Facilities Services will budget all facility costs (i.e., janitorial services, cleaning supplies, lease payments, parking, utilities) *for the corporate offices in* Cincinnati, Houston, Plainfield and Regulated Businesses centers for 2006. Personnel moves that benefit Cinergy as a whole or as a result of other moves will be budgeted within Site Services. Personnel moves requested by a department or group should be budgeted within the department's budget. Please call Tim Ryan 287-3065 for estimates on moves.

Facility projects are charged to the appropriate work definition as provided by the customer. In-house labor and materials are used to the extent possible and remain in facility centers. However, special projects that require over-time or outside contractors are charged directly to the customers center. This may also include minor materials. In circumstances that require a direct charge to the customer, the customer will be informed and provided an estimate of the charge prior to agreeing to provide the service.

6.2 Other Misc. Equipment/Service

- **Overnight Freight (United Parcel Service, FedEx, Airborne)**

  You are responsible for budgeting all overnight package delivery to your center. If you have any questions, please contact Don Schrantz at 287-3218.

- **EPRI Fees**

  EPRI fees are to be budgeted by the Business Units. Use the activity **ASSOCDUE**. Also, please remember to select the appropriate LOB to allocate the dollars between PSI and CG&E.

7.0 Information Technology (IT) Expenses

7.1 General Guidelines

Business Units are responsible for budgeting the following:

- PC Hardware and Software – existing, replacement, additional units, and upgrades
- Sales, use, and property taxes for all PC equipment
- PC Software Annual Maintenance and Desktop Management products
- Mainframe software maintenance and purchased items
- National Pagers
- Blackberries
- CG&E Private Pager Units
- Cell Phones
- Servers for Capital Projects
- Server Maintenance Time and Materials Cost (if not on Maintenance Contract)
  (Contact Frank Cook, Information Systems Operations, 287-3841 if you are not sure.)
- Phone Systems in remote locations (i.e., all offices outside of the Cincinnati 4th and Main complex and Plainfield CO)

Information Technology will budget the following, based on your requirements and input:

- Standard Pagers – SBC (formally Ameritech) Tri-State Regional Coverage Only. Indiana, Ohio and Northern Kentucky
- Server Hardware (unless you specifically request to budget the hardware in your own Responsibility Center(s))
- Server Maintenance Contracts
- Server Software (unless you specifically request to budget the software in your own Responsibility Center(s))
- Server Software Maintenance (unless you specifically request to budget the maintenance in your own Responsibility Center(s))

<u>IT Contacts:</u>

General Manager Sundance Office:	Ken Roth	513-419-5798
Regulated Business Non-Operating:	Sue O'Leary	513-287-3124
Regulated business Operational	Conny Toler	513-287-3886
Corporate Center:	Shirley Brown	513-287-3649
Shared Services	Shirley Brown	513-287-3649
Power Operations:	Mike Kehling	513-287-1932
Cincinnati Trading	Mike Schultz	513-419-5478
Houston Trading	Darrell Masseingale	713-393-6965

7.2 IT Expenses Budgeted by Business Units

PC'S AND RELATED EQUIPMENT

The acquisition of PC hardware, software and associated computer equipment (i.e., PC Desktops, Laptops, handheld units, etc.) is a centralized service performed by the IT organization. The RC Budget Tool has a link ("View PC Equipment" button) to the Remedy Asset Management System, which after entering your Responsibility Corp and Responsibility Center will display existing data of all PC computer equipment and associated software being leased. This link will display the dollar amount that should be budgeted to your Responsibility Center in 2006. Please keep in mind that this is real time data and the dollar amount is subject to change because equipment can be transferred to or from your Responsibility Center. **Important note: In addition to this dollar amount, you must add 12% to cover sales, use, and property taxes.**

Budget **$415 per PC** (leased or purchased) in your Responsibility Center for annual Microsoft software maintenance and associated Desktop management products. This $415 should be **budgeted in January** for every PC in your Responsibility Center.

While reviewing the data in the Remedy Asset Management System, you determine that changes need to be made to equipment within your Responsibility Center you will have to submit an information change request by clicking on the "Request Accounting Transfer" button on the Remedy Asset Inventory Query Screen. This is the only process for assuring the data will be up to date.

Note for Service Company Centers: Please budget PC lease costs to account 931xxx.

In addition, you may still need to make adjustments to your Responsibility Center's 2006 Plan as follows:

- Additional PCs that you will need for your Responsibility Center through December 2005 will need to be added to your budget. If you expect your Responsibility Center will add new employees or have increased PC needs for existing employees, you will need to budget for the monthly lease payments for these new PCs.

  For example, if you add new equipment in September 2005 you should budget 12 months of lease payments in the 2006 Budget. If you add new equipment in February 2006, you should budget lease payments starting March, 2006.

- PCs with a lease that will terminate between now and December 2005 will need to be added to your budget.

  For example, if you have equipment that goes off lease in September 2005 and you plan on replacing it, you should budget 12 months of lease payments in the 20056 Budget. If you have equipment that goes off lease in February 2006 and you plan on replacing it, you should budget lease payments starting March, 2006.

- Lease costs for new PCs for year 2006 continue to be based on a three-year leasing term, as they currently are for 2005.

  When budgeting for new or lease replacement PCs, use the following monthly, annual, or one-time cost:

- New Standard Desktop PC – $32 per month or $384 per year (includes system unit, memory, new or used monitor, & sales, use, and property taxes).

- New Standard Laptop PC – $49 per month or $588 per year (includes standard laptop configuration, memory & sales, use, and property taxes only; does not include docking station, floppy drive, keyboard, or monitor, which are non-standard). New Standard Laptop PC with docking station and monitor - $61 per month or $732 per year (includes standard laptop configuration, memory, docking station, floppy drive, keyboard, monitor & sales, use, and property taxes).

- In addition, budget a one-time charge of $181 for a lock, mouse, spare power cord, carrying case, and sales tax.

- Software/Miscellaneous Charges:
  - **Budget $415 per PC** (leased or purchased) in your Responsibility Center for <u>annual</u> Microsoft software maintenance and associated Desktop management products and services. This $415 should be budgeted in **January** for every PC in your Responsibility Center.
  - Budget for any specific software or software maintenance that your Responsibility Center incurs each year (i.e. SAS, Power Builder, Hummingbird Exceed, etc.).
  - Clients outside of Cinergy's service territory (Ohio, Indiana, Kentucky) will be responsible for budgeting shipping costs to send lease return items to Plainfield, Indiana. This cost will be dependent on the location you are shipping from.

If your PC related hardware or software requirements are not met by the equipment listed above, please contact Sandy Stanfield at 513-419-5729.

<u>Other IT Items</u>

- **Mainframe**

Budget for mainframe software maintenance and new purchases using Standard Activity **SWCOMPTR.**

- **Pagers**

National pagers - will continue to be administered by Central IT and service charges will continue to be directly charged to the local Responsibility Center. Cost is $60 per month.

CG&E Private Paging – The paging units for the CG&E Private Paging System will be a one time direct charge of $100.00 per unit. These charges are for any new or replacement units.

- **Blackberries**

All costs associated with blackberries are the responsibility of each Responsibility Center and must be budgeted using the activity code **PAGRCELL.** The Blackberry device is on one time charge of $150 - $190 depending upon the provider (See schedule below for IT Service Providers). Monthly charges for the data and voice should be budgeted as shown for your provider.

<u>IT Service Providers</u>

	Cingular	CBW	Verizon1
Voice Equipment			
Equipment (cell phone & accessories) – Note 1	$0.00	$0.00	$0.00
Base Monthly Charge	$0.00	$2.99	$9.99
Usage Charge per minute	$0.087	$0.070	$0.080
Roaming charge per month – Note 2	$0.00	$0.00	$0.00
Long Distance charges	$0.00	$0.00	$0.00
Text Message TO cell phone (i.e. from Outlook) per message	$0.00	$0.00	$0.02
Text Message FROM cell phone	$0.10	$0.10	$0.10
Data Equipment			
Blackberry & 'standard accessories' – one time purchase price	$150.00	$150.00	$190.00
Unlimited Data per month – add $5 to monthly service fee For all providers if Data only	$0.00	$30.00	$40.00

Note 1: Zero cost applies to Cinergy Standard Equipment ONLY. Verizon will ONLY provide the phone and a/c adapter at $0.00 cost. The Verizon vehicle power adapter, holster and ear bud costs approximately $50 to purchase.

Note 2: Verizon will charge $0.69 per minute if roaming on a non-Verizon network. This situation is somewhat rare but can happen within the US.

- **Cell Phones**

All costs associated with cell phones are the responsibility of each Responsibility Center and must be budgeted by each Responsibility Center. Use the activity code **PAGRCELL** to budget cell phones. Basic cell phone cost information will vary based on actual minutes used (See Appendix IX for provider costs). Central IT does NOT maintain data on a client's historical usage.

Please contact the IT Help Center (287-4357 or 838-2100) if you are in need of a cell phone to be turned off, name change, new accounting, etc.

- **Phone Systems or other phone needs**

All offices or locations outside of the Cincinnati 4th and Main complex and Plainfield CO should continue to budget for all additions, maintenance, move activities or the procurement of new phone equipment for the year 2006. If you need help developing a plan to meet your needs, please contact your Business Unit IT General Manager who will assist you in getting the appropriate members of the Central IT infrastructure team involved.

7.3 Expenses Budgeted by Central IT

Unless specifically directed otherwise, IT will budget and pay for the following:

- **Pagers**

  SBC (formally Ameritech) Tri-State Regional Coverage Pagers – coverage includes Indiana, Ohio and Northern Kentucky. Central IT will budget and pay for all pagers in 2006. These costs will be allocated to the Business Units.

- **Servers**

  Hardware:
  1) All lease payments for currently existing servers
  2) Projected lease payments for new server acquisitions anticipated, providing that IT is made aware of these purchase plans in time to include the dollars in the budgeting cycle
  3) Hardware maintenance, providing that a maintenance contract is selected. Any servers not covered under a maintenance contract will be subjected to Time & Materials charges should the server require repair. Any time and materials costs incurred will be charged to your individual Responsibility Center. Time & Materials charges will not be budgeted by Information Technology.

  Software:
  1) All lease payments for currently existing software
  2) Projected lease payments for new software purchases anticipated, providing that IT is made aware of these purchase plans in time to include the dollars in the budgeting cycle
  3) Software maintenance.

If you have any questions as to whether IT has budgeted for your servers, please contact Frank Cook, Information Systems Operations at 513-287-3841.

If you are currently paying for hardware or software out of your individual Responsibility Center, please notify the General Manager of the Sundance Office or CRM representative to determine if these costs should be incorporated within the Central IT budget.

Other IT Needs and Projects

Please consult the General Manager of the Sundance Office or CRM representative if you are planning to:

- Initiate any new IT projects which will require new PCs, servers, mainframe capacity, network upgrades, other IT infrastructure, etc.
- Deploy any new technology that is currently not part of the corporate standards.
- Acquire new hardware or software. New software acquisitions may be eligible for accounting treatment as lease, purchase, or capitalization of costs.
- Budget license maintenance on existing mainframe software.

8.0 Capital Expenses

8.1 Capital vs. Expense

General Equipment Purchases

The purchase of general equipment (i.e., tools, office furniture and equipment, store's equipment, etc.) must have a unit price of $1,000 or more to be classified as a capital expenditure. When the cost of an item is less than $1,000 per item, these costs must be charged to an operating expense activity.

Other Property Purchases

To determine whether an expense should be charged to construction (capitalized) or charged to expense, the Property Unit Catalog is to be reviewed. Expenditures for the acquisition or replacement of property units as defined in the Property Unit Catalog are to be budgeted to a construction project. Plan expenditures for non-capital work (as defined in the Catalog) are to be charged to an operating expense activity.

8.2 Capitalized Computer Software

Cinergy regularly incurs costs for the acquisition and/or development of business systems applications and/or other internal use software that may be used by one or more companies or organizational units within the Cinergy group.

Whenever the cost of acquiring, developing and/or implementing new computer software will exceed $100,000 and the expected useful life of the software exceeds 5 years, certain costs of such software are to be capitalized:

1. Acquisition cost of purchased software
2. All internal labor related costs, including the cost of fringe benefits and payroll taxes, of team members dedicated to the project. An employee is dedicated to a Capital software project when the employee spends a minimum of 500 hours on the project.
3. Cost of hardware and software devoted exclusively to the development and/or implementation of software
4. Consultant fees directly related to the project
5. Out of pocket expenses of team members dedicated to the project
6. Allowances for Funds Used during Construction (AFUDC)

Please refer to the following Software Policy for guidance:

https://web.cinergy.com/faa/Policies%20&%20Procedures/ComputerSoftwarePolicy1998 .doc

Administrative and General Costs and Training Costs should not be capitalized.

Data conversion costs are not capitalized except for the cost to develop or obtain software that allows for access or conversion of old data.

Internal use computer software that is included in research and development activities is to be expensed. Research and development includes software utilized in a particular research and development project, software that is a pilot project, or the formulation, design and testing of possible internal use computer software project alternatives.

Costs incurred during the Preliminary Project Stage are not capitalized. These costs include conceptual formulation of alternatives, evaluation of alternatives, determination of existence of needed technology, final selection of alternatives including vendor and consultant selections.

Labor costs and incidental expenses of employees occasionally assisting in the development of the software are not to be capitalized. These costs include focus group participation, interviews and time spent on supplying information to an implementation team.

Costs incurred after the software's in-service date (date when the system is used in the day-to-day operations of the company including completion of all substantial testing) should not be capitalized, unless such costs are a "major enhancement", as defined in the following paragraph.

Major enhancements to existing systems are to be capitalized if they meet the same criteria described above for new systems. Recurring minor costs of maintaining or updating existing software and minor costs of new software should be charged directly to expense.

Costs for systems applicable to the day-to-day functions performed by the Service Company should be capitalized on the books of the Service Company. Costs applicable to the day-to-day operations of one or more operating companies should be capitalized on the books of the operating company or companies which include the functions responsible for the administration of the system. Any questions regarding the appropriate company for capitalization of costs, or which costs should be capitalized, should be directed to the Fixed Assets. Please contact Amy Dean in Cost Accounting prior to budgeting capital items on the Service Company.

The designated project manager is responsible for ensuring that all applicable expenditures are charged to the proper Company and capital or expense accounts in accordance with this policy.

Any questions regarding the appropriate company for capitalization of costs, or which costs should be capitalized, should be directed to Brenda Melendez at 287-1554.

9.0 Service Company Guidelines

9.1 Labor and Employee Related Expenses

Each Service Company function is responsible for budgeting its individual departmental expense (labor and employee related expenses) using Corp Code 500, and their individual responsibility center. To assign costs to the appropriate Client Companies and/or Lines of Business (LOB), you must use an LOB code. Please contact your BU coordinator for the appropriate LOB code to use.

9.2 Contracted Services and Materials

All non-employee related expenses (services and/or materials) are to be budgeted directly to the Client Company and /or LOB those benefits from these services and/or materials. To budget directly to a Client Company, use the appropriate Client Company corporation code (not Corp Code 500), your individual responsibility center, and the appropriate LOB code

If you have any questions about the Service Company guidelines or not sure whether you should budget to the Service Company, please contact your Financial Coordinator for assistance or Amy Dean in Cost Accounting at 838-6972. For additional information on accounting for Service Company charges please refer to Section 5.1, Service Company Accounting, of the Accounting Policy and Procedure manual located on the Cinergy Intranet (http://web/plantacct/policy.htm).

10.0 Budgeting for CIN-10 Initiative

Due to the results of CIN-10, a variety of corporate wide activities were assessed and new policy and procedure changes were implemented. The following discusses the changes that impact the budgeting process. Total CIN-10 savings in 2005 were $50M and a total savings of $80M in 2006. In 2005 $50M in CIN-10 savings were removed from the budgets. Only the incremental $30M in CIN-10 savings is to be removed from the 2006 budgets.

Budget Input Instructions

Upper management has been clear about the need that all CIN10 savings continue to be visibly tracked and reported. Therefore, the following procedure was established for entering CIN10 savings/additions into each responsibility center budget for 2006:

Labor

- Two "organizations" exists in the Employee Labor Pool screen. They are **CIN10 staff reduction** and ***CIN10 staff* addition.**
- If a center is to reduce an FTE, a **CIN10 staff reduction** line should be added to their center labor pool.
- If a center is to add an FTE, a **CIN10 staff addition** line should be added to their center labor pool.
- A center needs to put in the net of the additions and subtractions.
- Actual employees should <u>not</u> be claimed or unclaimed due to CIN-10. Positions only should be added or reduced by adding one of the above "organizations" under the vacancy category.
- If you have employee transfers between departments, the receiving department should code the "CIN10 Addition", the departing center should code the "CIN-10 Reduction". Again, these are positions, not actual employees being transferred.
- Only the employee labor pools in the ELB Tool will be updated with CIN10 labor impacts. No input will be required in the RC Budget Tool.
- Centers can not add any vacancies, including CIN-10 vacancies, until their BU president / vice president approval is given via the vacancy request form.
- Vacancy request forms will be run through the BU Financial Groups.

Non-Labor

- The project "CIN10" was established and should continue to be used.
- Each center will choose the project (CIN10) via their budget input screen. Under this project credits will be entered for each Activity / Corp / LOB / Account combination shown on their center report.
- Budgets should be developed with Pre-CIN10 dollars with CIN10 adjustments being made to the "CIN10" project.

  Example
  A CIN10 idea for center XXX is to eliminate $5,000 of relocation expenses in 2005 and $16,000 in 2006. Center XXX had budgeted a net $20,000 to the activity relocation in the 2005 budget ($25,000 less 2005 savings of $5,000). Therefore, in the 2006 budget, they will enter $20,000 under the relocation activity. Under the "CIN-10" project and the relocation activity they will enter a credit of $11,000. The net result will be $9,000 budgeted to the activity relocation in 2006. (Incremental difference between 2005 and 2006 savings.)

- *The business only needs to budget for the incremental amount from 2005 to 2006.*
- Q1-Q6 (Q3 2004 – Q4 2005) ideas will be budgeted at their incremental full-run rate in 2006. If your center has an idea which is a Q7 or Q8 (Q1 2006 or Q2 2006) idea, you will be only budgeting a partial incremental run-rate which will be shown in the '06 incremental column of the NPE Report.

10.1 Center Specific Changes

Personnel Expenses

The following is an example of a personnel / FTE report that will be produced from the CIN10 Implementation Tracking System. This report will show each responsibility center the personnel FTE/Headcount and dollars to be reduced and/or added to their 2006 budget.

The dollars on the PE spreadsheet are average direct dollars. The business can choose to put in the exact direct dollars for the CIN-10 additions / subtractions in lieu of the average.

BU	group_ id	cost center id	cost_center	job_title	orig salary band	band avg	Salary	capture_action	capture_timing	add / subtrac
CC	11	GEN	Corporate Accounting	Analyst	6	63.71	49.0567	Attrit	Q8	Add
CC	11	GEN	Corporate Accounting	Sr Analyst	6	63.71	49.0567	Attrit	Q8	Add
CC	11	CVI	Cinergy Ventures Investments	Mgr Investments	3	120.42	92.7234	Select Filled	Q8	subtract
CC	11	145	Corporate Development	Mgr Origination	3	120.42	92.7234	Select Filled	Q8	subtract

You will have to estimate the number of vacation, holidays, or any other losttime to enter with each position.

Non-personnel Expenses

Presented below is an example of a center report that will be produced from the CIN10 Implementation Tracking System. This report will show each responsibility center the non-personnel dollars to be reduced and/or added to their 2006 budget.

23 LEGAL

Business Unit	Center	Activity	Timing	Corp	LE Alloc	RBU	CBU	PTIS	Work Type	Amount	2005	2006	Incremental 2006	200
171 9692 Corp Ctr	23 LEGAL	ADMNSTRA	Q1	500 - C	LEG	9.20	6.73	0.07	Operations	16.00	16.00	16.00	0.00	16
175 9701 Corp Ctr	23 LEGAL	ADMNSTRA	Q3	500 - C	LEG	1.14	0.84	0.02	Operations	2.00	1.75	2.00	0.25	2
187 9783 Corp Ctr	23 LEGAL	ADMNSTRA	Q4	500 - C	LEG	3.62	2.65	0.03	Operations	6.30	3.94	6.30	2.36	6
188 9765 Corp Ctr	23 LEGAL	OFFICSUP - OFFICE SUP & EXP	Q3	500 - C	LEG	14.38	10.51	0.11	Operations	25.00	21.87	25.00	3.12	25
172 9694 Corp Ctr	23 LEGAL	OFFICSUP - OFFICE SUP & EXP	Q2	500 - C	LEG	0.18	0.12	0.00	Operations	0.30	0.30	0.30	0.00	0
176 9703 Corp Ctr	23 LEGAL	OFFICSUP - OFFICE SUP & EXP	Q1	500 - C	LEG	2.02	1.46	0.02	Operations	3.50	3.50	3.50	0.00	3
184 9746 Corp Ctr	23 LEGAL	OFFICSUP - OFFICE SUP & EXP	Q1	500 - C	LEG	1.49	1.09	0.02	Operations	2.60	2.60	2.60	0.00	2
199 9801 Corp Ctr	23 LEGAL	OSSER - OUTSIDE SERVICES	Q2	500 - C	LEG	1.39	1.01	0.00	Operations	2.40	2.40	2.40	0.00	2
200 9803 Corp Ctr	23 LEGAL	OSSER - OUTSIDE SERVICES	Q2	500 - C	LEG	0.12	0.08	0.00	Operations	0.20	0.20	0.20	0.00	0
196 9794 Corp Ctr	23 LEGAL	OSSER - OUTSIDE SERVICES	Q1	500 - C	LEG	0.35	0.25	0.00	Operations	0.60	0.60	0.60	0.00	0
197 9797 Corp Ctr	23 LEGAL	OSSER - OUTSIDE SERVICES	Q1	500 - C	LEG	0.06	0.04	0.00	Operations	0.10	0.10	0.10	0.00	0
183 9742 Corp Ctr	23 LEGAL	OSSER - OUTSIDE SERVICES	Q3	500 - C	LEG	1.78	1.30	0.02	Operations	3.10	2.71	3.10	0.39	3
201 10451 Corp Ctr	23 LEGAL	OSSER - OUTSIDE SERVICES	Q4	500 - C	LEG	1.61	1.18	0.01	Operations	2.80	1.75	2.80	1.05	2
202 10451 Corp Ctr	23 LEGAL	OSSER - OUTSIDE SERVICES	Q4	500 - C	LEG	-0.81	-0.59	0.00	Operations	-1.40	-0.87	-1.40	-0.52	-1
177 9708 Corp Ctr	23 LEGAL	SUBSCRP - PUBLICATION SUB	Q1	500 - C	LEG	2.31	1.67	0.02	Operations	4.00	4.00	4.00	0.00	4
178 9709 Corp Ctr	23 LEGAL	SUBSCRP - PUBLICATION SUB	Q1	500 - C	LEG	0.98	0.71	0.01	Operations	1.70	1.70	1.70	0.00	1
182 9722 Corp Ctr	23 LEGAL	SUBSCRP - PUBLICATION SUB	Q1	600 - C	LEG	0.12	0.08	0.00	Operations	0.20	0.20	0.20	0.00	0
185 9747 Corp Ctr	23 LEGAL	SUBSCRP - PUBLICATION SUB	Q1	500 - C	LEG	0.29	0.21	0.00	Operations	0.50	0.50	0.50	0.00	0
203 9742 Corp Ctr	23 LEGAL	SWNPURCH - SOFTWARE PURC	Q3	500 - C	LEG	-23.00	-16.82	-0.18	Operations	-40.00	-35.00	-40.00	-5.00	-40
Total Amount										29.90	26.24	29.89	1.65	29

Note: All amounts are shown in thousands. Positive amounts are to be entered as reductions in the budget. Negative amounts are to be entered as additions to the budget. (+) = Savings / (-) = Costs.

<u>Explanation of the fields on the report:</u>

<u>Business Unit</u> – this represents what business unit your center belongs to.
<u>Center</u> – this is the responsibility center in which all of your CIN10 reductions/additions will occur.
<u>Activity</u> – what work or service you are performing or receiving.
<u>Timing</u> – Q1 = 3rd quarter, 2004
Q2 = 4th quarter, 2004
Q3 = 1st quarter, 2005
Q4 = 2nd quarter, 2005

Q5 = 3rd quarter, 2005
Q6 = 4th quarter, 2005
Q7 = 1st quarter, 2006
Q8 = 2nd quarter, 2006

The savings within a quarter are spread as follows: month 1 = 0%; month 2 = 50%; month 3 = 100%
For example, if an idea was being implemented in Q7 with an amount of $2,000 the savings for this idea would be spread as follows:

$2,000 / 12 = $167 / month
January, 2006 = 0
February, 2006 = $167 x 50% = $83
March – December, 2006 = $167/month or a total of $1,667
Total for 2006 = $83 + $1,667 = $1,750

Corp – identifies what corporation should be budgeted
LEAlloc – This is used only for corp 500 transactions. This allocator tells the system how to allocate the dollars from corp 500 to a final corporation. The user will need to convert the LEAlloc to the new LOB code block structure. Please consult your Financial Coordinator for assistance with this conversion.
RBU / CBU / PTIS – Shown in thousands. This identifier is used by Corporate Center and Shared Service groups only. This entry identifies how much should be allocated to each of the BU's (RBU, CBU, or PTIS)
Work Type – the work type will help identify what account should be budgeted.
Amount – Shown in thousands. This identifies the annual savings amount for an idea.
2005 / 2006 / '06 incremental to be budgeted / 2007 – Shown in thousands. This shows the savings and/or additional dollars that should be reduced/added to the center budget for each year shown. For the 2006 budget only reduce / add the dollars shown in the "'06 incremental to be budgeted" column.

One-Time Costs

MANAGER TAX

usiness Unit	Center	Activity	Timing	Corp	LE Alloc	RBU	CBU	PTIS	Work Type	Amount	2004	2005	2006	2007
rp Ctr	34 MANAGER TAX	PRPTXINS - PROPERTY TAXES AND INSUR	Q3	010 - THE	N/A	-503.00	-56.00	0.00	Maintenance	-559.00	0.00	-559.00	0.00	0.0
rp Ctr	34 MANAGER TAX	PRPTXINS - PROPERTY TAXES AND INSUR	Q5	100 - PSI	N/A	-401.40	-44.60	0.00	Taxes - Other	-446.00	0.00	-446.00	0.00	0.0
tal Amount										-1,005.00	0.00	-1,005.00	0.00	0.0

One time costs – Only 2006 information is shown as this is the final year a business would have CIN-10 one-time costs. Negative dollars are costs and positive dollars are savings on the spreadsheet.

One time:
(+) = Savings
(-) = Cost

10.2 Non-Center Specific Changes

The following describes CIN10 ideas that were not identified to a specific center and for which savings span across the entire Cinergy organization. The savings for these initiatives will either be captured at the BU level or at the Center level. The Financial Operations group for each business unit will determine how these savings will be implemented for their organization. Presented below are descriptions and the associated savings for each of these initiatives.

Please note to only budget **differential between 2005 and 2006**. For example, for subscriptions Shared Services would budget a $30,000 savings in 2006 (difference between $50,000 in 2005 and $80,000 in 2006). Another example would be wireless initiative where Shared Services would not have to budget any incremental dollars in 2006 since 2005 and 2006 are the same amount.

- External Training

The amount of individual external training was addressed through the CIN10 initiative. A study will be completed sometime during the fall of 2005 to determine how much external training is occurring across the business units. Once assessed and implemented, sometime in 2006, a cap for external training for each employee will be established and a policy implemented. With the conclusion of the study, the allocation of the 2006 budget reduction to the business units will be determined and communicated. For budgeting purposes, the business units will share the 2006 reduction equally.
All savings should be made to the **TRAINREC** Activity.
Any questions about this initiative should be directed to Steve Allen at 419-6936.
Individual responsibility centers should budget as normal (assuming no reduction), a high level credit will be entered at the BU level.

	2005	2006	Incremental	2007
Corporate Center	0	62,500	62,500	62,500
CBU	0	62,500	62,500	62,500
RBU	0	62,500	62,500	62,500
Shared Services	0	62,500	62,500	62,500
Total	0	250,000	250,000	250,000

- Electronic Invoicing Strategy (2% discount in 10 days, net 45)

The discount idea is to move from a NET 30 company to a 2%, 10 day, NET 45 company. This means that we would take a discount of 2% for payments within ten days and otherwise pay in 45 days.
This idea has three components:

- First, build the capabilities of taking discounts and to move as many invoices to electronic transactions as possible.
- Secondly, take all discounts of 2% in ten days. This piece is separated between capital and O&M with the capital portion accounting for 10% of the capital spend and the O&M portion accounting for 50% of the spend.
- Thirdly, move the remaining payables from NET 30 days to NET 45 days.

The net total for this idea is $7.6 million. To put this in perspective with $1.9 billion in spend, taking a 2% discount on all of this spend would yield $38 million. This idea represents 20% of the total potential of that spend.

These are one-time costs that need to be de-budgeted by the business units. It is important for the business units to approve all electronic invoices in less than 10 days to assure that these savings are occurring.

The Activity in which these savings will be captured should follow the same accounting as the *original invoicing*.
Any questions about this initiative should be directed to Lisa Carver at 838-1937.
Individual responsibility centers should budget as normal (assuming no reduction), a high level credit will be entered at the BU level.

	Q3, 2005	Q5, 2005	Q8, 2006
Corporate Center	219,600	219,600	329,400
CBU	1,342,000	1,342,000	2,013,000
RBU	756,400	756,400	1,134,600
Shared Services	122,000	122,000	183,000
Total	1,220,000	1,220,000	3,660,000

- **Wireless Initiative**

Cinergy has almost 7,000 wireless devices including cellular phones, pagers, and blackberries. IT continues to work with the business units to eliminate unnecessary wireless devices.
All savings were be made to the **PAGRCELL** Activity in the 2005 budget. No incremental savings required to be entered in 2006. Questions about this initiative should be directed to Gail Farwick at 287-3422.

	2005	2006	2007
Corporate Center	72,900	72,900	72,900
CBU	172,300	172,300	172,300
RBU	347,800	347,800	347,800
Shared Services	72,900	72,900	72,900
Total	665,900	665,900	665,900

- **PC Asset Utilization**

IT continues to enforce the current standards policy for purchasing PC's and eliminate any unnecessary peripherals and equipment on PC's. All savings were be made to the **HWCOMPTR** Activity in the 2005 budget. No incremental savings required to be entered in 2006.
Any questions about this initiative should be directed to Gail Farwick at 287-3422.

	2005	2006	2007
Corporate Center	13,000	13,000	13,000
CBU	26,000	26,000	26,000
RBU	26,000	26,000	26,000
Shared Services	13,000	13,000	13,000
Total	78,000	78,000	78,000

- **Donations**

Approximately $500,000 in contributions are made annually to not for profit organizations, including schools, hospitals, community groups, etc. This is above and beyond the $6.5M that the Cinergy Foundation Board approves through the Corporate Foundation. The Cinergy Foundation Board asks that **ALL** charitable giving occur through the approved Cinergy Foundation guidelines and budget. Therefore all charitable donations should be removed from the individual center budgets.
All savings should be made to the **DONATENC** Activity.
Any questions about this initiative should be directed to Joe Hale at 287-2410.
Individual responsibility centers should not budget for donations.
All savings were entered in the 2005 budget. No incremental savings required to be entered in 2006.

	2005	2006	2007
Corporate Center	25,000	25,000	25,000
CBU	25,000	25,000	25,000
RBU	25,000	25,000	25,000
Shared Services	25,000	25,000	25,000
Total	100,000	100,000	100,000

- **Relocation Savings**

Components of the relocation package provided to exempt employees who relocate due to a job change or who are newly hired will be changed to reflect current market conditions. For example, both the reimbursement to an employee for costs incurred in selling his or her home and the miscellaneous expense allowance associated with moving to a new location will be changed.

The Company will continue to have sole discretion in determining the circumstances when a relocation package should be offered.

All dollars were budgeted to the **RELADMIN** Activity in the 2005 budget. No incremental savings required to be entered in 2006.
Any questions about this initiative should be directed to Sue Gray at 838-1142.

	2005	2006	2007
Corporate Center	71,000	71,000	72,000
CBU	173,200	173,200	173,200
RBU	5,700	5,700	5,700
Shared Services	0	0	0
Total	249,900	249,900	249,900

- **Exempt Overtime (OT) Meal Allowance**

The exempt overtime (OT) meal allowance was eliminated.
All savings were made to the **ADMNSTRA** Activity in the 2005 budget. No incremental savings required to be entered in 2006.
Any questions about this initiative should be directed to Karen Feld at 287-2729.
Individual responsibility centers should not budget for exempt overtime meal allowance.

	2005	2006	2007
Corporate Center	9,000	9,000	9,000
CBU	37,800	37,800	37,800
RBU	10,500	10,500	10,500
Shared Services	1,500	1,500	1,500
Total	58,800	58,800	58,800

- **Subscriptions**

This is the implementation of the CIN-10 idea to eliminate redundant and duplicate paid print and electronic subscriptions throughout Cinergy. The new subscription policy adds an accountability component that requires GM's and above to confirm that each subscription ordered has a legitimate business purpose, thus eliminating duplicate subscriptions. Secondly, it enables better tracking and reporting of total subscription spends by having all new subscriptions processed by Strategic Sourcing. Effective immediately, no paid subscriptions will be processed via employee expense reports.
All savings should be made to the **SUBSCRP** Activity.
Any questions about this initiative should be directed to Mark Craft at 287-2066.
Individual responsibility centers should budget as normal (assuming no reduction), a high level credit will be entered at the BU level.

	2005	2006	Incremental
Corporate Center	65,600	105,000	39,400
CBU	65,900	105,500	39,600
RBU	65,900	105,500	39,600
Shared Services	50,000	80,000	30,000
Total	247,400	396,000	148,600

- **Printers / Copiers**

During the CIN-10 process, a proposal to reduce the reliance on paper throughout the company was approved. This initiative focused on workflow improvements and consolidation of printing/copying devices. The industry average ratio of printing devices to employees is 10:1. Cinergy is currently at 3.7:1. Over the next two years our goal is to get as close to the industry average as possible.

One of the first steps in this process is to consolidate all costs associated with printing, copying and faxing. For the 2006 budget cycle you **should not** budget for any printers, copiers, fax machines or associated consumables such as toner, ink cartridges or paper. The dollars for these items will be budgeted centrally.

All items budgeted centrally will be allocated back based on actual use as this process moves forward. For example when you make a print the print spooler behind the scenes will keep track of your user id and the details of your printing request. This information will be consolidated and used to bill back the costs associated with that job. An online monthly report will be available to managers that detail their groups copying and printing volumes.
All savings should be made to the **OFFEQUIP** Activity.
Any questions about this initiative should be directed to Steve Hinkel at 419-5345.
Individual responsibility centers should not budget for printers, copiers, fax machines, or associated consumables. A high level debit and credit will be entered by Corporate IT.

	2005	2006	Incremental	2007
Corporate Center	5,200	10,300	5,100	10,300
CBU	49,800	124,600	74,800	124,600
RBU	55,500	186,500	131,000	186,500
Shared Services	34,900	107,100	72,200	107,100
Total	145,400	428,500	283,100	428,500

- **Meal Cap Reimbursement**

Cinergy will reimburse employees at a maximum daily rate of $56.00 for meal costs they have incurred when staying overnight in a location that is not their regularly assigned work location. If meal costs exceed the $56.00 meal cap, it will be the employee's responsibility to cover the difference between what has been spent and the $56.00 meal cap.
This meal cap is different from a meal per diem. Employees who spend less than the $56.00 a day for meals will not be entitled to the difference between what they spend and the $56.00 rate. *This meal cap reimbursement should be* reviewed periodically and updated as necessary. Recommended breakdown of meal costs:

Meal	Amount
Breakfast	$12.00
Lunch	$16.00
Dinner	$28.00

All reimbursement costs which exceed the $56.00 meal cap, must be accompanied with a receipt and will require manager approval.
All savings should be made to the **ADMNSTRA** Activity.
Any questions about this initiative should be directed to Dale Butler at 287-3191.
Individual responsibility centers should budget as normal (assuming no reduction), a high level credit will be entered at the BU level.

	2005	2006	Incremental	2007
Corporate Center	14,000	112,500	98,500	112,500
CBU	4,500	35,700	31,200	35,700
RBU	12,000	96,400	84,400	96,400
Shared Services	14,000	112,500	98,500	112,500
Total	44,500	357,100	312,600	357,100

- **IT Governance**

Beginning with the 2005 budget process, the IT Department assumed the budget for all capital and O&M IT dollars. The business units will still budget their own labor dollars in respect to any IT project that will occur during the budgeting process. Each group will need to work with their respective Customer Relationship Managers (CRM's) to identify scope estimate and identify business value of both O&M and capital projects in 2006. This will be needed so they can be reviewed and approved by the respective business units before being placed in the budget. The CRM for Corporate Center and Shared Services is Shirley Brown (287-3649), RBU Operations is Conny Toler (287-3886), RBU is Sue O'Leary (287-3124), CBU Trading Operations is Greg Schultz (419-5478) and CBU Power Operations / Generation is Mike Kehling (287-1932). Therefore, the business units *should not budget for O&M* or capital IT dollars.
Any questions about this initiative should be directed to Ken Roth at 419-5798.

- **Parking**

Effective 1/1/05, Executives (GM's and above) began paying for the parking benefit that they receive from the company. These charges will be deducted from their paychecks. Therefore centers **should not** budget for these expenses.

The following is the process to budget for manager parking, but was not part of the CIN-10 process.
Cinergy will continue to pay for managers who park at the 3rd & Main parking garage. Real Estate Services will pay the consolidated bill for manager parking at 3rd & Main and the costs will be distributed to the individual Center through a journal entry in 2006. Each center should budget **$140/month per manager** for 3rd and Main Parking for 2006

Parking expenses should be budgeted to the **ADMNSTRA** Activity and **PARKING** project.
Any questions about this initiative should be directed to Steve Ruehlman at 287-3043.

11.0 Cost Pool Guidelines

11.1 Stores, Freight and Handling Cost Pool (excluding Commercial Business Unit)

The costs associated with buying, receiving, storing and issuing materials are aggregated in the Stores, Freight and Handling cost pool and loaded out by attaching an additional charge to material issuances. This additional charge is known as the stores, freight and handling (SF&H) loading.

Please budget all storeroom related costs, including, but not limited to, the following:

- Storeroom labor and expenses
- Purchasing
- Maintenance of stores equipment
- Inventory record keeping
- Handling of scrap materials
- Freight
- Obsolete materials

Important Note: The Commercial Business Unit does not budget ANY cost to the SF&H Cost Pool. All costs associated with buying, receiving, storing and issuing materials are budgeted and charged directly to expense.

11.2 Transportation Cost Pool (excluding Commercial Business Unit)

The costs associated with acquiring, storing, operating and maintaining the Company's fleet of vehicles are aggregated in the Transportation cost pool and loaded out by applying a cost rate (loading) to the hours of use of the vehicle fleet.

These costs include, but are not limited to, the following items:

- Fleet lease expenses (payments, terminations)
- Maintenance costs (parts and labor)
- Operating costs (Fuel costs and costs of providing fuel to vehicles)
- Tax, licensing and registration costs
- Fleet administration

All costs except lease costs, insurance, licenses and taxes (which are centrally budgeted by Transportation Services) related to the company's fleet of vehicles are to be budgeted to the Transportation Cost Pool using the activities identified in Appendix V in the respective cost pool centers. These cost pool centers include the Cincinnati central garage, Plainfield central garage and the West districts.

Transportation loading rates are developed to clear out the cost pool based on vehicle utilization (number of hours per month). Please see Section 4.6 (Transportation) for instructions on budgeting dollars of usage for vehicles.

Important Note: The Commercial Business Unit does not budget ANY cost to the Transportation Cost Pool. All costs associated with acquiring, storing, maintaining and issuing fleet vehicles are budgeted and charged directly to expense.

11.3 Construction Overhead

Construction Overheads consist of two major categories: A&G overheads and Functional overheads.

Administrative and General (A&G) Construction Overhead

A&G construction overheads are the costs associated with the work that A&G functions perform for capital projects. In general, the costs of administrative and general functions (i.e., accounting, purchasing, and accounts payable) are charged 100% to A&G expense. However, these functions perform a certain level of work associated with capital projects. Cost Accounting performs an annual study by center to determine the percentage of A&G costs that are allocated to capital. Cost Accounting will budget for indirect A&G construction overhead costs utilizing the annual A&G Cost Study. .

If you have any questions concerning the allocation of A&G costs to construction overhead, please contact your Financial Coordinator or Brad Clayton at 838-2058.

Functional Construction Overheads:

Departments that provide *direct and indirect* construction support, such as Engineering & Construction, will budget a portion of their labor to budget schedules 898 and/or 899. These schedules contain projects that are **required** when budgeting. For assistance, please contact your Financial Coordinator.

The general guidelines for being able to charge construction overheads is that anyone directly involved in construction activities can charge construction overheads. Anyone who directly supports those who are directly involved in construction activities can also charge construction overheads. However, anyone who supports someone who supports those directly involved in construction activities should not be charging the overhead pool. This is the general "2-levels-away" concept we have been trying to comply with, coming from construction accounting GAAP for non-regulated entities.

Budget Schedule 898 – Direct Functional Construction Overheads

This schedule is used by departments that provide direct construction support to construction projects. For example, if a person (or department) is assigned 100% to support the construction of an SCR at Gibson Station then all of that person's (or departments) labor will be charged directly to that construction project, via Schedule 898. This schedule is used to identify capital work that will be charged directly to capital projects/work orders throughout the year. Following below is a standardization that has been established for the Account\Corp\Project to help users budget correctly for their direct *functional construction* overheads. If you don't know the appropriate combination to use please consult your Financial Coordinator.

			Projects						
References	Account - Account Description	Corp	107DST	107GAS	107GLP	107GNL	107PRDDR	107SUB	107TRN
1	107000 - CWIP UTILITY PLANT	010	X	X	X	X		X	X
1	107000 - CWIP UTILITY PLANT	070	X	X	X	X	X	X	X
1	107000 - CWIP UTILITY PLANT	100	X		X	X	X	X	X
2	107005 - CWIP UTILITY PLANT - CA	500	X	X	X	X	X	X	X
1	107500 - NON-REG CWIP - ELECTRIC	NON-REG					X		
2	107505- NON-REG CWIP - ELECTRIC - CA	500					X		
1	107530 - NON -REG CWIP - OTHER	NON-REG			X	X			
3	107530 - NON -REG CWIP - OTHER	500			X	X			
2	107535 - NON-REG CWIP - OTHER - CA	500			X	X			
1	107850 - NON-UTILTY CWIP	NON-REG			X	X			
2	107852 - NON-UTILITY CWIP - OTHER	600			X	X			
2	107855 - NON-UTILITY CWIP - CA	500			X	X			
1	108410 - RWIP - UTILITY PLANT	010, 070, 100	X	X	X	X		X	X
2	108415 - RWIP - UTILITY PLANT - CA	500	X	X	X	X	X	X	X
1	108540 - NON-REG RWIP ELECTRIC	010 , 618					X		

References

1) Mapped to Balance Sheet on client companies
2) For Cost Assignment (CA), mapped to Income Statement on Corp 500
3) Mapped to Balance Sheet on Corp 500

Budget Schedule 899 - Indirect Functional Construction Overheads:

This schedule is used by departments that provide construction support to a number of construction projects. For example, a person works in T&D engineering and they perform engineering related work for numerous T&D construction projects throughout the year will budget to the proper function of schedule 899. This schedule contains projects that are established to associate capital overhead work with the proper function. This schedule is for overhead costs that will not be charged directly to capital project work orders but are truly "overhead" in nature. As always, please budget capital costs (in Budget Schedule 898) to be charged directly to specific projects when at all possible to reduce the amount of dollars that is included in the capital overhead pool. Following below is a standard that has been established for the Account\Corp\Project to help users budget correctly for their indirect functional construction overheads. *If you don't know the appropriate combination to use please consult your Financial Coordinator.*

Budgeting your time to the appropriate functional overhead project (e.g., transmission, distribution, production, gas) will allow the costs to be spread over all of the direct capital projects budgeted to that function. Your Construction Overhead (899) work codes are also to be set up in BDMS to point to the projects to which you budgeted.

Following is a breakdown of the 899 accounts and associated projects that should be used for budgeting:

Account – Account Description	Corp	107DSTOH	107GASOH	107GLPOH	107PRDOV	107SUBOH	107TRNOH
107000 – CWIP Utility Plant	010, 070, 100	X	X	X	X	X	X
107005 – CWIP Utility Plant CA	*500*	X	X	X	X	X	X

Service Company (Corp. 500) Employees: When you are supporting both East and West construction, please allocate using a LOB Allocator code. Budgeting and charging accordingly will allow us to manage the overhead pool and maintain one overhead rate per function.

Please direct questions concerning functional capital overheads to Dave Schafer at 287-2822 for RBBU and Susan Miller at 419-5442 for EMBU. Please direct questions concerning A&G overheads to Brad Clayton at 838-2058.

11.4 Indirect Labor Cost Pool

Indirect Labor is a cost associated with employees' non-productive time (ex. Vacation, Holidays) that is aggregated in a cost pool and loaded out by attaching an additional charge to the direct labor dollars.

The ELB tool will automatically calculate your indirect labor cost pool for vacations, holidays, and personal days. The ELB tool will also calculate the provision of the union labor agreement for an additional 40 hours of sick pay. This pay will be reflected in the January indirect labor cost pool budget for each regular Union employee in your center. Individual departments may budget for any additional Sick Time, such as a planned operation, which the user wants to reflect in the plan.

> *40 hours sick pay is calculated by taking all Union employees with IBEW, IUU, USW (formerly USWA -excludes USWA 8183 and PACE) and sums the total of FTEs for that center. It takes the 40 hours sick pay Xs January's average hourly rate and Xs it by the total number of FTEs. It loads the payroll tax and the fringe benefit rate to get the loaded rate. Then it's put into the table to show up under the cost pool worktype. This will not affect your labor utilization report.*

In addition, the Business Units and Corporate Center departments will budget to the Indirect Labor Cost Pool using the standard activities listed in Appendix V.

12.0 Budget Reporting

Direct Reporting (Budget Input Verification)	
Tool	**Description**
Detail Dashboard (Direct Dollars)	Primary use is to ensure budget data was entered into the RC Budget tool correctly by a single Responsibility Center. This tool is recommended to be used for budget input verification purposes only; all analysis should occur the next day on fully loaded dollars.
Hyperion Reports (Direct Dollars)	Various reports can be run to view budget data (direct dollars) previously entered by the user. All of these reports can be found under the "Budget Input Verification" folder within Hyperion Reports. These reports are ideal if the user wishes to view their direct dollars using two or three code block dimensions.
Summary Dashboard (Direct Dollars)	Warning! Not real-time reporting! The overall database aggregation occurs nightly; therefore, this tool should only be used for a single Responsibility Center. The user can view their detail Responsibility Center data using the code block hierarchies.
ELB Management Reports (Direct Dollars)	Warning! Not real-time reporting! Information entered in the RC Budget tool is fed nightly to the ELB Management reports; therefore, all direct dollar reporting reflects the information as of close of business the day before. This is a relational reporting tool that allows the users to query on direct dollars using pivot table functionality.
Fully Loaded Reporting (Budget Analysis)	
Tool	**Description**
Hyperion Reports	Financial Statement Report (Standard View) – This report should be generated the following morning (after budget input is complete) so users can view their impact to Cinergy financial statement line items. This is the report that will be used by management to hold users accountable. Found under the "Financial Statement Stmt View Reports" folder.
	Budget Analysis Reports – There are various reports under the "Budget Analysis" folder that users should access to perform analysis on the budget data. There are numerous reports targeted for the Responsibility Center, Line of Business (LOB), or Project owner to view how direct or indirect charges affect their bottom line.
	Budget Input Verification – Just as there are budget input verification reports for "direct" dollars, the users can view their budget data in the same manner for "fully loaded" dollars. These reports are ideal if the user wishes to view their budget using two or three code block dimensions. These reports are found under the "Budget Input Verification Reports" folder.
Detail Dashboard (Fully Loaded Dollars)	Warning! The Detail Dashboard is not to be used to view massive amounts of data (i.e., BU-levels or summary rollups at the lowest level). This ad-hoc reporting tool allows the user to view data for analysis purposes.
Summary Dashboard (Fully Loaded Dollars)	This ad-hoc reporting tool allows the Center, LOB, or Project owner to analyze their budget data using the code block hierarchies (i.e., start at a high-level and drill-down to focus analysis).
ELB Management Reports (Fully Loaded Dollars)	Relational reporting tool that allows the users to query on fully loaded budget data using pivot table functionality.

13.0 ELB / RC Budget Tool Training

All training simulations and eLearning courses can be accessed via the IPower Web at Communities / Finance & Accounting / Budget & Forecasts / Training Materials.

Simulations

- Establish center defaults and input labor information
- Launch Aggregate – ELB business rule and run Labor Utilization Report
- Enter labor hours / non-labor dollars and launch other business rules
- Run the RC budget detail dashboard report
- Run the Standard Financial Statement View report

eLearning courses

- RC Overview

14.0 BU Specific Guidelines

14.1 CBU Generating Stations & Generation Resources Guidelines

Labor and Employee Related Expenses – Generation Resources

All Exempt, Non-Exempt & Union employees under Generation Resources will be in Corp 500.

Labor and Employee Related Expenses – Generating Stations

All Non-Exempt and Union employees will be in either Corp 010 (CG&E) or Corp 100 (PSI) with the exception of Power Services and Optimization & Employee Development who will ALL be in Corp 500 (exempt, union & non-exempt). **Please note: for budgeting, you may budget to the corp that your costs would ultimately end up on rather than trying to split your budget between corp 500 for exempt and client corp for all others.**

Contracted Services and Materials

All non-employee related expenses (services and/or materials) are to be budgeted directly to the Client Company that benefits from these services and/or materials. To budget directly to a Client Company, use the appropriate Client Company corporation and your individual responsibility center.

Specific Budget Items

- ***Switchyard Equipment***: As in past years, Regulated Business Unit budgets the labor associated with work on the switchyard equipment (i.e. Step-Up Transformers) owned by Commercial Business Unit and CBU budgets the materials. Any materials budgeted for work that Regulated Business Unit will be doing should be budgeted to the applicable activities and accounts.

PI: You should include dollars in your budget for Plant Information (data archive system that records data from plant controls and sensors at the station) annual maintenance. Budget the same amount as in 2005 plus a 5% increase to activity **ITSUPPRT**. The allocation of costs is based on the value of the software that was purchased by each station. For more information you can contact Don Zalac, at 287-1906. **This is an annual charge and should be budgeted in the month of March.**

Following are the projected 2006 PI (Plant Information) annual maintenance amounts:

Location	Pct Usage	Cost
Beckjord	7.3%	$ 19,254.85
Brownsville	2.1%	$ 5,554.04
Caledonia	2.0%	$ 5,274.09
Cayuga	7.6%	$ 20,215.69
East Bend	7.0%	$ 18,623.20
EMS West	N/A	$ 14,651.44
EMS East	N/A	$ 15,842.90
Florence Trading Center	N/A	$ -
Gallagher	5.8%	$ 15,401.63
Gibson	12.0%	$ 31,709.23
Henry County	4.4%	$ 11,601.87
Madison	5.6%	$ 14,839.61
Miami Fort	7.3%	$ 19,221.08
Noblesville	3.1%	$ 8,218.52
Performance Diagnostic Center	4.2%	$ 11,168.57
Texas City	9.1%	$ 24,112.52
Tuscola	1.7%	$ 4,425.79
Wabash River & Repower	12.1%	$ 32,046.86
Woodsdale	3.6%	$ 9,559.19
Zimmer	5.2%	$ 13,768.33
Total	100.0%	$295,489.42

- **PTR+:** You should include dollars in your budget for PTR (safety and tagging software) annual maintenance. The amount to be budgeted is $60,000 to activity **ITSUPPRT.** The projected purchase price is $400,000 plus a 15% maintenance fee. The allocation of costs is based on capacity at each station. For more information you can contact Don Zalac, at 287-1906. **This is an annual charge and should be budgeted in the month of March.**

  Following are the projected 2006 Safety and Tagging Software Maintenance Fee:

Pct Usage	Corp	Center	LOB	Cost
26.50%	100	2TS	GBC	15,900.00
10.91%	10	PZT	ZIM	6,546.00
10.44%	10	PM3	MFC	6,264.00
9.44%	10	PBT	BJ8	5,664.00
8.44%	100	287	CCY	5,064.00
5.61%	100	246	W26	3,366.00
5.37%	100	MDP	MDC	3,222.00
5.37%	100	2RP	WRR	3,222.00
5.04%	10	PE2	EB2	3,024.00
4.70%	100	256	CGA	2,820.00
3.88%	210	VMP	3PT	2,328.00
2.20%	10	PW1	WGS	1,320.00
1.34%	100	226	EDW	804.00
0.76%	100	230	NBB	456.00
100.00%				60,000.00

- **Maximo:** The following is the allocation of costs to be used for budgeting the Maximo Software Maintenance fees. It is based on the number of users per station. Budget the same amount as in 2005 plus a 5% increase to activity **ITSUPPRT. This is an annual charge and should be budgeted in the month of March.**

Location	Corp	Center	Work Code	LOB	Pct Usage	Cost
Gibson	100	2TS	EMITSPST	GBC	24%	$41,280.00
Miami Fort	010	PM3	EMITSPST	MFC	12%	$20,640.00
Zimmer	010	PZT	EMITSPST	ZIM	12%	$20,640.00
Beckjord	010	PB2	EMITSPST	BJ8	10%	$17,200.00
Cayuga	100	CCY	EMITSPST	CCY	7%	$12,040.00
East Bend	010	EB2	EMITSPST	EB2	7%	$12,040.00
Wabash (Wabash River)	100	W26	EMITSPST	W26	7%	$12,040.00
Gallagher	100	CGA	EMITSPST	CGA	6%	$10,320.00
Edwardsport	100	EDW	EMITSPST	EDW	2%	$3,440.00
Noblesville	100	NBB	EMITSPST	NBP	2%	$3,440.00
Dresser	100	380	DRSOMITSP	NSB	1%	$1,720.00
Markland	100	MAC	EMITSPST	MAC	1%	$1,720.00
Beckjord CT's	010	BCP	CTITSUPP	BC5	1%	$1,720.00
Brownsville	617	BRT	CTITSUPP	BRC	1%	$1,720.00
Henry County	100	CDC	CTITSUPP	CDC	1%	$1,720.00
Caledonia	618	CAL	CTITSUPP	CAC	1%	$1,720.00
Cayuga CT	100	CPR	CTITSUPP	4CY	1%	$1,720.00
Madison	100	MDC	CTITSUPP	MDC	1%	$1,720.00
Vermillion	210	3PT	3POFFSUP	3PT	1%	$1,720.00
Wabash (Repower)	100	WRR	CTITSUPP	WRR	1%	$1,720.00
Woodsdale	010	WGS	CTITSUPP	WGS	1%	$1,720.00
Connersville					0%	$0.00
Dick's Creek					0%	$0.00
Miami-Wabash					0%	$0.00
Total					100%	$172,000.00

- **Environmental Permits:** Questions regarding these fees can be directed to Steve Pearl, Environmental, at 838-1758. Budget to **ENVROAIR** for air permits and **ENVWATER** for water permits. (See schedule below)

Environmental Permits & Fees

		2005	2006	2007
Cayuga	Air	$226,000	$230,000	$235,000
	Asbestos	$750	$750	$750
	NPDES	$32,000	$34,000	$36,000
Edwardsport	Air	$226,000	$230,000	$235,000
	Asbestos	$750	$750	$750
	NPDES	$16,000	$17,000	$18,000
	Strm.Wtr.	$135	$150	$150
Gallagher	Air	$226,000	$230,000	$235,000
	Asbestos	$750	$750	$750
	NPDES	$32,000	$34,000	$36,000
Gibson	Air	$226,000	$230,000	$235,000
	Asbestos	$750	$750	$750
	Sld. Waste	$32,000	$34,000	$36,000
Noblesville	Air	$226,000	$230,000	$235,000
	Asbestos	$750	$750	$750
	NPDES	$12,000	$14,000	$15,000
Wabash Rvr.	Air	$226,000	$230,000	$235,000
	Asbestos	$750	$750	$750
	NPDES	$32,000	$34,000	$36,000
Destec	Strm.Wtr.	$135	$150	$150
Universal Mine	Strm.Wtr.	$750	$800	$900
Connersville	Air	$27,000	$29,000	$32,000
Miami Wab.	Air	$20,000	$25,000	$30,000
Markland	NPDES	$525	$550	$600
Henry County	Air	$20,000	$25,000	$30,000
	NPDES			

KENTUCKY FACILITIES

East Bend	Air	$334,000	$350,000	$368,000
	water			

OHIO FACILITIES

Beckjord	Air	$420,000	$446,000	$473,000
	NPDES	$28,000	$30,000	$32,000
Miami Fort	Air	$372,000	$393,000	$420,000
	NPDES	$27,000	$30,000	$32,000
Lawrencbrg Lndfil.	NPDES			
Zimmer	Air	$420,000	$446,000	$472,000
	NPDES	$25,000	$30,000	$35,000
Zimmer Landfill	Air			
	Water			
Woodsdale	Air	$18,000	$19,000	$20,000
	NPDES	$1,800	$2,000	$2,500
Dicks Creek	Air	$18,000	$19,000	$20,000
Madison	Air	$18,000	$19,000	$20,000

- **ESC CEMS Software Maintenance Contract:** This maintenance contract should be budgeted in 2006 and beyond. The price will remain constant through the payments in 2005 and 2006, as a 3-year commitment with ESC was signed to hold the price steady during the 3 years. In 2007 and beyond the payments will increase somewhat. The yearly contract payment is a lump sum payment paid late May or early June. (See schedule below)

	2005-2006	%-age of total amount	Payable amount
Cayuga	$10,845.00	6.06%	$10,845.00
Cayuga CT	$5,422.50	3.03%	$5,422.50
Connersville	$10,845.00	6.06%	$10,845.00
Edwardsport	$21,690.00	12.12%	$21,690.00
Gallagher	$21,690.00	12.12%	$21,690.00
Gibson	$32,535.00	18.18%	$32,535.00
Henry County	$16,267.50	9.09%	$16,267.50
Noblesville CT	$16,267.50	9.09%	$16,267.50
Wabash River	$16,267.50	9.09%	$16,267.50
Wabash Repowering	$27,112.50	15.16%	$27,112.50

- **Obsolete Material:** For the 2006 budget, we will be budgeting for obsolete materials. Stations and Storerooms will be responsible for identifying and reviewing obsolete material. Obsolete material provision will need to be established and budgeted for.

Centers using Pay-for-Service Methodology for Dresser Shop

Stations should budget any work utilizing Dresser Shop as follows:

- Station center and LOB
- Contract Labor resource
- Contract Material resource

The Center 380 budget will be established based on all expected labor expenses and shop overhead operating expenses. All expenses will be budgeted to Center 380. As services are requested by the stations and during the work in process (WIP), all costs associated with the work will be charged to Center 380, account 186992. Upon job completion all costs, including labor, will be transferred via journal entry to the appropriate station center, station workcode, and station LOB. In the journal entry all labor will be charged to the Contract Labor resource and all materials will be charged to the Contract Material resource.

Planned Outages

Any "Scheduled" outages should be budgeted to applicable outage project. If you have any questions, please contact Mike Hofmann (287-2886).

Appendix I – Loading Rates

Below are the loading rates to be used at the beginning of the budgeting process. These rates will be reviewed during the course of the budget cycle and updated as necessary.

Fringe Benefits	41.00% for 2006
Indirect Labor:	
Union	32.00%
Non-Union	20.00%
Payroll Taxes	7.50%
Stores, Freight and Handling (SF&H):	
Non-Production	8.00%
Minor Material:	
CG&E	5.00%
PSI	6.00%
ULH&P	5.00%
Helicopter	$1,000 (per hour)

Appendix II – Direct and Fully Loaded Views in Hyperion Reports

Difference between Direct and Fully Loaded

Direct

Resource	Account		
1113 - Labor - Union Direct Dollar	502000 - Steam Expenses	$20,000	
2111 - Stock Materials	502000 - Steam Expenses	$500	
2431 - Contract Labor	502000 - Steam Expenses	$200	
		$20,700	
1113 - Labor - Union	184610 - Indirect Labor Clearing - Union	$3,000	*The $3,000 is the indirect labor dollars that are assigned to the cost pool found on the balance sheet Salary = Direct + Indirect (20,000 + 3,000 = 23,000)

Fully Loaded

1113 - Labor - Union	502000 - Steam Expenses					$20,000
2111 - Stock Materials	502000 - Steam Expenses					$500
2431 - Contract Labor	502000 - Steam Expenses					$200
1253 - Payroll Taxes - Union	408220 Account - Payroll Taxes - Nonutility	$20,000	X	9.1%	=	$1,818
1213 - Fringe Benefits - Union	926000 Account - Employee Pension & Benefits	$20,000	X	49.5%	=	$9,902
1233 - Indirect Labor - Union	502000 - Steam Expenses	$20,000	X	21.9%	=	$4,380
2121 - SF&H	502000 - Steam Expenses	$500	X	10.0%	=	$50
						$36,850

**) allocations HAVE occurred.
** .y loaded dollars are updated in a nightly batch job.

Labor Loadings			
Payroll Taxes	7.5%	+ 1.59% =	9.1%
Fringe Benefits	41.0%	+ 8.51% =	49.5%
Indirect Labor	32.0%	- 1.59%- 8.51% =	21.9%

By Account	(502000)	(926000)	(408220)	(184600)	
By Line Item	**Production Operation**	**Admin & General**	**Taxes Other Then Income Taxes**	**Misc Clearing Accounts**	**Total**
Direct	$20,700			$3,000	$23,70
Fully Loaded	$25,130	$9,902	$1,818		$36,85

Appendix III – Average Hourly Labor Rate Calculation

Average Hourly Labor Rate Calculation for 2006 Plan Year:

The monthly average hourly labor rates used in the RC Budget Tool are calculated as follows:

For this example, let's assume a center has 16 full-time Exempt FTE's. Their total Base wages as shown in the "Adjust Labor Pool" screen is $1,118,256. Their annual increase amount is $37,275 (starts in March, 2006).

The following shows the number of worked hours in each month during 2006.

	Hours Per Month
Jan	176
Feb	160
Mar	184
Apr	160
May	184
Jun	176
Jul	168
Aug	184
Sep	168
Oct	176
Nov	176
Dec	168
	2,080

Average Hourly Rate Calculation:

January and February:
Base Dollars / 12 Months / Hours in Month / # of Employees in Center

January $1,118,256 / 12 = $93,188 / 176 hours = $529.48 / 16 = $33.09
February $1,118,256 / 12 = $93,188 / 160 hours = $582.43 / 16 = $36.40

March thru December:
(Base Dollars / 12 Months) + (Annual Increase Dollars / 10 Months) = Total Monthly Base
Total Monthly Base / Hours in Month / # of Employees in Center

March ($1,118,256 / 12 = $93,188) + ($37,275 / 10 = $3,727.50) = $96,915.50
$96,915.50 / 184 = $526.71 / 16 = $32.92

Appendix IV – Vacation, Holiday and Other Entitlement

Vacation Entitlement:

- Number of years is based on the service date (adjusted employment date).
  Exception: For employees hired during the year, the incremental process uses the effective hire date.
- For employees rehired during the year, the incremental process calculates their vacation based on service date using the standard rules. The employee actually receives 1/12 of those calculated hours for each full month he/she will be here this year. For example, if hired June 15th, the employee will receive 6/12 or just half of their calculated vacation hours. These hours are given to the employee immediately.
- For most benefit plans, the individual receives the additional week of vacation when reaching the milestone length of service anytime within the year. A few plans force the employee to wait until after their service anniversary before being eligible to take the additional week.
- For most benefit plans, employees meeting a milestone are entitled to the additional time as of the beginning of the year. They do not have to wait until their anniversary date before receiving the additional time.
- Part-Time employees are not eligible for vacation in every benefit plan. They may be required to work a certain number of hours a week before being eligible.
- The entitlement for full or part time people working less than 40 hours a week is reduced based on the number of hours they are scheduled to work each week. For example, if working 24 hours a week and entitled to 2 weeks of vacation, the individual receives 48 hours of vacation. If the proration results in a fractional hour, the final result is always rounded up to the next whole hour. For example, 22.2 is changed to 23 hours.
- Employees will accrue 1/12th of current year's vacation entitlement per month. Active regular employees may use current year vacation at any time during the year as approved by management. Upon terminating employment during the year, employees will be paid the accrued amount less what vacation has already been taken.
- Nonunion and IBEW 1347 became entitled to six weeks of vacation after 32 years of service effective January 1, 2005. *USWA 12049 and 5541-06 IBEW 1393 and UWUA will be entitled to six weeks of vacation after 32 years of service* effective January 1, 2006. However, the additional week must be banked for retirement in years 32 thru 34.

[illegible]s	Non-Union	USWA 12049 and 5541-06	USWA 8183	UWUA	IBEW 1347	IBEW 1393	IUOE 399	PACE	ERA	IBEW 352	UNITE LOCAL 2024	UNITE LOCAL 1093t
Less than 1	1 day per month (max 10)	1 day per month (max 10)	None	1 day per month (max 10)	1 day per month (max 10)	None	None	1 day per month (max 10)	None	None	None	None
1	2 weeks	2 weeks	2 weeks	2 weeks	2 weeks	2 weeks	1 week	2 weeks	2 weeks	2 weeks	2 weeks	2 weeks
2 – 6	2 weeks	2 weeks	2 weeks	2 weeks	2 weeks	2 weeks	2 weeks	2 weeks	2 weeks	2 weeks	2 weeks	2 weeks
7	3 weeks	3 weeks	3 weeks	3 weeks	3 weeks	3 weeks	2 weeks	3 weeks	3 weeks	3 weeks	3 weeks	3 weeks
8 – 14	3 weeks	3 weeks	3 weeks	3 weeks	3 weeks	3 weeks	3 weeks	3 weeks	3 weeks	3 weeks	3 weeks	3 weeks
15 - 16	4 weeks	4 weeks	4 weeks	4 weeks	4 weeks	4 weeks	3 weeks	4 weeks	4 weeks	4 weeks	4 weeks	4 weeks
17 – 20	4 weeks	4 weeks	4 weeks	4 weeks	4 weeks	4 weeks	4 weeks	4 weeks	4 weeks	4 weeks	4 weeks	4 weeks
21 – 24	5 weeks	5 weeks	5 weeks	5 weeks	5 weeks	5 weeks	4 weeks	5 weeks	5 weeks	5 weeks	5 weeks	5 weeks
25 – 33	5 weeks	5 weeks	5 weeks	5 weeks	5 weeks	5 weeks	5 weeks	5 weeks	5 weeks	5 weeks	5 weeks	5 weeks
34 and above	6 weeks*	6 weeks	5 weeks	6 weeks	6 weeks*	6 weeks	5 weeks	6 weeks	6 weeks	5 weeks	5 weeks	5 weeks
Part-Time Eligibility	Yes No minimum	No	No	Yes *if 20 or more hrs/ wk*	No	No	No	No	No	No	No	No
Effective	Jan 1st	Jan 1st	Jan 1st	Jan 1st	Jan 1st	Jan 1st after the first year	Service Anniversary	Jan 1st	Jan 1st	Service Anniversary	Jan 1st	Jan 1st

Holiday Entitlement:

- This category reflects the **maximum** number of holiday pay a person **may** receive for a year. Any employee, full or part time, is only eligible to receive holiday pay if the holiday falls on a day they normally are scheduled to work.
- There is no prorating for people working less than 40 hours a week.
- This category is only used by the budgeting application.
- Holiday entitlement is not calculated within the incremental process.
- Part time employees are eligible in selected benefit plans.
- In one benefit plan, the person must be employed for a minimum length of time before being eligible for holiday pay. The length of service is based on the service date (adjusted hire date).

*Eligibility is really dependent on probationary status rather than 9 months. Using "9 months" for consistent terminology across all categories.

	Non-Union	USWA 12049 and 5541-06	USWA 8183	UWUA	IBEW 1347	IBEW 1393	IUOE 399	PACE	ERA	IBEW 352	UNITE LOCAL 2024	UNITE LOCAL 1093T
Holidays:	8 days	8 days	8 days	8 days	8 days	11 days	6 days	8 days	8 days	8 DAYS	8 days	8 DAYS
Minimum Employment	No	No	No	No	No	9 months*	No	No	12 months (probation)	9 Months	No	No
Part-Time Eligibility	Yes	No	No	Yes	No	No	No	No	No	No	No	No
Part-Time Entitlement	Yes	None	None	Yes	None	None	None	None	None	None		

Other Entitlement:

- Part time employees are not eligible in any benefit plan.
- In most benefit plans, the person must have been employed for a minimum length of time before being eligible for this type of paid time off. The length of service is based on the inputted date and service date (adjusted hire date). The incremental process ignores the service date for employees hired / rehired during the year.
- Personal days for non-union and PACE employees hired / rehired in the current year are adjusted based on their hired date. This is only checked within the incremental process.
- *The entitlement is based on the 8 hours worked per day unless otherwise specified.* Employees working 10 hour days and entitled to 4 personal days actually receive 40 hours of personal time. Someone working 4 twelve hour days would receive 48 personal hours and a 12 hour diversity day.

	Non-Union	USWA 12049 and 5541-06	USWA 8183	UWUA	IBEW 1347	IBEW 1393	IUOE 399	PACE	ERA	IBEW 352	UNITE LOCAL 2024	UNITE LOCAL 1093T
Personal Days:	4 days *	4 days	1 day	4 days	4 days	None	2 days	4 days *	4 days	40 HOURS	1 DAY	1 Day
Minimum Employment	No	6 months	6 months	6 months	6 months		1 year	1 year	6 months	No	6 Months	6 months
Diversity Days:	1 day	1 day	1 day	1 day	1 day	1 day	None	1 day	1 day	None	1 day	1 day
nimum ployment	No	6 months	6 months	6 months	6 months	9 months		1 year	6 months		No	No
Floaters:	None	None	None	None	None	1 day	2 days	None	None	None	None	None
Minimum Employment	None	None	None	None	None	9 months	None	None	None			
Retirement Bank	1 week age 51 – 56 up to entitlement. Can start at age 47	1 week age 51 – 56 up to entitlement. Can start at age 47	No	1 week age 51 – 56 up to entitlement. Can start at age 47	1 week age 51 – 56 up to entitlement. Can start at age 47	1 week age 51 – 56 up to entitlement. Can start at age 47	No	No	No	No	No	No
Minimum Employment	No	N/A for new hires after 1/1/06	No	N/A for new hires after 1/1/06	N/A for new hires after 1/1/06	N/A for new hires after 1/1/06						

- Employees hired between April 1st and June 30th of current year only receive 3 personal days. Employees hired between

July 1st and September 30th of current year only receive 2 personal days. Employees hired on or after October 1st of current year only receive 1 personal day. Employees hired before April 1st get the entire 4 personal days.

PACE employees are also reduced based on the month they are hired even though they do not actually receive any personal days until their first service anniversary.

Appendix V – Standard Activities

Indirect Labor Cost Pool

Activity	Activity Description
ADLEAVE	Adoption Leave – Union and Non-Union
DPLEAVE	Domestic Partner Leave – Union and Non-Union
FMLEAVE	Family Medical Leave - Union and Non-Union
HOLIDAYS	Holidays – Union
LOSTTIME	Lost Time (Vacation, Sick, Holidays) – Non - Union
OTHPDAB	Other Paid Absences/Voluntary Off - Union
PTLEAVE	Paternity Leave – Union and Non - Union
RETBANK	Retirement Bank
SCHDMTG	Scheduled Safety and Training Meetings - Union
SICKNESS	Sickness – Union
STDIS	Short Term Disability
UNIONBUS	Union Business – Union
VACATN	Vacations – Union
WEATHOTH	Inclement Weather - Other - Union
WEATHTRN	Inclement Weather - Training - Union
WRKCOMP	Workers Comp - Union and Non-Union

Transportation Cost Pool

Activity	Activity Description
ADMNSTRA	Administration & General
LEASERNT	Leasing / Rentals
VDEPR	Vehicle Depreciation
VFUELOH	Fuel Over / Under
VFUEL	Vehicle Fuel Purchases
VMAINT	Vehicle Maintenance - Chassis
VHYD	Vehicle Maintenance - Hydraulic
VRENT	Equipment rental in the Transportation Services Fleet
VPROCESS	Processing of New and Old Vehicles
VGARAGE	General Garage Activities
VMISC	Miscellaneous Transportation Department Expenses
VEHINS	Vehicle Insurance
VEHREG	License Fees and Taxes
VLEASE	Lease Rental Cost

Appendix VI – Vacancy Request / Approval Process

This form can also be accessed via IPower / Communities / Finance & Accounting / Budget & Forecasts / Reference Documents

Vacancy Request Form

Submitted By:

Approved By:

Center	Organization	Title/Position	Labor Class	Salary (unloaded)	FTE	Vacation / Personal	Holidays	From Date	To Date	Sick Time	Already Approved by Jim R. (Y/N)	Comments/Justification
	Available in drop down box:		Available in drop down box:									
	Incremental		Exempt									
	IncrementalHired		Non-Exempt									
	Replacement		Union									
	ReplacementHired											
	Cin-10 Addition											
	CIN-10 Reduction											

Appendix VII – ELB / RC Budget Tool Security Request Form

This form can be accessed via the IPower Web at Communities / Finance & Accounting / Budget & Forecasts / Reference Documents – RC Budget Tool Security Form

ELB/RC BUDGET TOOL SECURITY FORM

User Name ____________________
User ID ____________________
Manager Name ____________________
BU CFO ____________________ * Please click the drop down box for CFO list.

ELB BUDGET TOOL

	1st Center	2nd Center	3rd Center	4th Center	5th Center
1. What center (detail or summary) do you need security to?					
2. Do you need to update employee labor records?					
3. Do you need to view employee salaries?					
4. Do you need the ability to Close/Open a center?					
5. Do you need to run reports?					

Please note:
If in question 1, you need access to 001, 002, 003, 004, 008 or SSG, *you will need approval from your manager* and BU CFO.

If you answered 'YES' to question 3, you will need approval from your manager and BU CFO.

RC BUDGET TOOL

	1st Center	2nd Center	3rd Center	4th Center	5th Center
6. What center (detail or summary) do you need security to?					
7. Do you need access to input the budget					
8. Do you need access to run reports					

All security must be approved by your manager and BU CFO if applicable from above.

When Completed:
1. **User** - forward this worksheet to your manager for approval
2. **Manager** - if no BU CFO approval required, forward this worksheet to #CC Finance
   If BU CFO approval required, forward this worksheet to them
3. **BU CFO** - forward this worksheet to # CC Finance

Appendix VIII – 2006 Transportation Cost

2006 TRANSPORTATION COST

	ANNUAL COST			
2600 - *Transportation*	RATE	HOURS	TOTAL ANNUAL COST	MONTHLY COST
2601 - Class 1 Sedans				
2611 - 1A Basic Sedan (Non-commuting)	$3.50	2080	$ 7,280.00	$ 606.67
2612 - 1B Basic Sedan (Commuting)	$4.25	2080	$ 8,840.00	$ 736.67
2613 - 1C Executive Class Sedan	$6.00	2080	$ 12,480.00	$ 1,040.00
2619 - 1D Luxury Executive Class Sedan	$8.25	2080	$ 17,160.00	$ 1,430.00
2602 - Class 2 SUVs				
2614 - 2A Base SUV (Non-commuting)	$5.25	2080	$ 10,920.00	$ 910.00
2615 - 2B Base SUV (Commuting)	$6.75	2080	$ 14,040.00	$ 1,170.00
2616 - 2C Exec. Class SUV	$7.50	2080	$ 15,600.00	$ 1,300.00
2603 - Class 3 Vans				
2617 - 3A Mini Van	$4.65	2080	$ 9,672.00	$ 806.00
2618 - 3B Full-Size Van	$5.65	2080	$ 11,752.00	$ 979.33
2604 - Class 4 Pickup Trucks				
2631 - 4A Compact PU 4x2 (Non-commut)	$4.75	2080	$ 9,880.00	$ 823.33
2632 - 4B Compact PU 4x4 (Non-commut)	$5.25	2080	$ 10,920.00	$ 910.00
2633 - 4C Compact PU (Commuting)	$5.50	2080	$ 11,440.00	$ 953.33
2634 - 4D Full - PU 4x2 (Non-commut)	$4.50	2080	$ 9,360.00	$ 780.00
2635 - 4E Full - PU 4x4 (Non-commut)	$5.50	2080	$ 11,440.00	$ 953.33
2636 - 4F Full - PU (Commuting)	$7.25	2080	$ 15,080.00	$ 1,256.67
2637 - 4G Full - PU 4x2 (Commuting)	$5.50	2080	$ 11,440.00	$ 953.33
2605 - Class 5 Utility Trucks and Other Equip				
2651 - 5A Utility Body 4x2 Under 1 Ton	$7.50	2080	$ 15,600.00	$ 1,300.00
2652 - 5B Utility Body - Heavy Duty	$7.75	2080	$ 16,120.00	$ 1,343.33
2653 - 5C HD Util 4x4;Tract;Dump;Svc	$11.00	2080	$ 22,880.00	$ 1,906.67
2654 - 5D Stake w/Mtd Derr;Trk Tract	$11.65	2080	$ 24,232.00	$ 2,019.33
2655 - 5E Bucket Truck 4x2 (Over 40')	$12.50	2080	$ 26,000.00	$ 2,166.67
2656 - 5F Mtl Handler/Line Trks 4x2	$15.30	2080	$ 31,824.00	$ 2,652.00
2657 - 5G Mtl Hndlr Bkts 6x4/Line Trk	$17.50	2080	$ 36,400.00	$ 3,033.33
2660 - 5H Util Body 4x4 under 1 ton (Non Con	$6.50	2080	$ 13,520.00	$ 1,126.67
2661 - 5I Util Body 4x2 under 1 ton (Com)	$6.15	2080	$ 12,792.00	$ 1,066.00
2662 - 5J Utility Body 4x4 under 1 ton (Com)	$7.00	2080	$ 14,560.00	$ 1,213.33
2664 - 5X HD Util 4x4 Tractors; Hd Dump Tru	$13.00	2080	$ 27,040.00	$ 2,253.33
2665 - 5Y Material Handlers/Line Trucks 4x2 -	$17.00	2080	$ 35,360.00	$ 2,946.67
2663 - 5R Rental Bucket and Derric Trks	$32.00	2080	$ 66,560.00	$ 5,546.67
2606 - Class 6 Step Vans				
2658 - 6A Step Vans	$9.00	2080	$ 18,720.00	$ 1,560.00
2659 - 6B Step Vans w/mounted equip	$13.00	2080	$ 27,040.00	$ 2,253.33
2607 - Class 7 Heavy Equipment				
2671 - 7A Puller tensioners	$2.75	2080	$ 5,720.00	$ 476.67
2672 - 7B Sweep;Frklft;Bkhoe;Trnch	$4.75	2080	$ 9,880.00	$ 823.33
2673 - 7C HD Construction Equipment	$20.00	2080	$ 41,600.00	$ 3,466.67
2674 - 7D High Expense Constr Equip	$37.00	2080	$ 76,960.00	$ 6,413.33
2675 - 7E Very High Exp Constr Equip	$72.00	2080	$ 149,760.00	$ 12,480.00
2677 - 7F Low Expense Constr Equip	$1.25	2080	$ 2,600.00	$ 216.67
2676 - 9 Trailers & Misc Other Veh				

**** For vehicles that follow LDCS - Do not forget to add hours for overtime/storm work!!!!

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(9)(d)

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807 KAR 5:001, SECTION 10(9)(d)

Description of Filing Requirement:

Annual and monthly budget for the 12 months preceding the Filing Date, the Base Period, and Forecasted Period.

Response:

See the attached for the Company's official 2005 and 2006 budgets which include the 12 months preceding the Filing Date (May. 2005-Apr. 2006) and the Base Period (Sep 2005-Aug 2006). The requested annual budget for the 12 months of the forecasted test period is provided in Schedules C-1. The monthly revenue and monthly O&M amounts are shown in workpapers WPC-2c and WPC-2.1a, respectively. This data is comprised of the Duke Energy Kentucky's 2006 annual budget as adjusted by Mr. Davey in his testimony and the extension for 2007 (Jan-Dec) also described in Mr. Davey's testimony.

Sponsoring Witness: Brian P. Davey

Duke Energy Kentucky
Income Statement
DEK Electric Rate Case - 2005 Budget

	2005 Jan	2005 Feb	2005 Mar	2005 Apr	2005 May	2005 Jun	2005 Jul	2005 Aug	2005 Sep	2005 Oct	2005 Nov	2005 Dec	Total 12 Months
Operating Revenues													
Retail Revenues	20,467	17,681	18,666	16,706	18,636	22,337	25,678	24,812	20,617	17,511	17,682	20,137	240,928
Sales for Resale Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
Off System Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Transfer Revenue/Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Electric Revenues	11	11	11	2,383	1,025	641	949	1,281	535	1,500	1,200	1,172	10,719
Total Electric Revenues	20,477	17,692	18,677	19,088	19,662	22,978	26,627	26,093	21,152	19,011	18,882	21,309	251,647
Firm Sales	30,091	20,086	13,374	4,236	951	3,163	3,513	3,539	3,837	7,293	15,165	28,751	133,999
Transportation	446	443	380	291	211	177	170	168	182	206	273	389	3,334
Other Gas Revenues	26	25	26	29	28	27	26	25	28	27	26	31	324
Total Gas Revenues	30,562	20,555	13,779	4,556	1,191	3,366	3,708	3,732	4,047	7,526	15,464	29,170	137.657
Other Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating Revenues	51,040	38,246	32,456	23,644	20,852	26,344	30,335	29,826	25,199	26,537	34,346	50,479	389.304
Operating Expenses													
Fuel used in electric production	966	788	575	4,345	4,510	4,712	5,923	5,977	4,340	4,031	3,945	4,537	44,649
Purchased and exchanged power	15,010	13,160	13,100	859	1,535	3,221	4,578	4,103	2,842	1,573	1,594	1,979	63.554
Total Emission Allowances	-	-	-	429	111	32	28	54	25	213	203	179	1,274
Total Electric Cost of Goods Sold	15,976	13,948	13,675	5,633	6,156	7,966	10,528	10,134	7,208	5,817	5,742	6,694	109.478
Gas purchased	22,638	14,047	8,747	1,451	(690)	1,518	1,824	1,871	2,414	5,127	11,332	21,967	92,246
Other Operations & Maintenance Total	4,764	4,460	4,184	8,334	6,862	6,589	6,511	6,466	6,900	6,735	6,721	6,769	75,296
Depreciation	1,611	1,614	1,632	3,196	3,208	3,238	3,259	3,267	3,272	3,277	3,283	3,302	34.158
Property tax expense	379	379	379	611	611	611	611	611	611	611	611	611	6,635
Payroll tax expense	116	109	102	173	169	165	164	157	164	170	168	167	1,825
Revenue tax expense	1	-	-	1	-	-	1	-	-	1	-	-	3
Other tax expense	-	-	-	-	-	-	-	-	-	-	-	-	-
Taxes other than income taxes total	496	488	481	785	780	776	775	768	775	781	779	778	8.463
Total Operating Expenses	45,485	34,556	28,720	19,399	16,316	20,087	22,898	22,505	20,569	21,739	27,858	39,510	319,640
Pretax Operating Income	5,555	3,691	3,737	4,245	4,537	6,257	7,437	7,321	4,630	4,798	6,488	10,969	69,664
Income Taxes													
State Income Tax	374	223	227	218	234	373	470	462	243	256	394	761	4,235
Federal Income Tax	1,520	954	969	938	999	1,519	1,881	1,854	1,031	1,082	1,602	2,976	17,324
Income Taxes Total	1,894	1,176	1,196	1,156	1,233	1,892	2,351	2,316	1,274	1,338	1,996	3,737	21,559
Operating Income	3,661	2,515	2,541	3,089	3,304	4,365	5,086	5,005	3,356	3,460	4,492	7,231	48,105
Other Income (Expense), Net													
Allowance for equity funds used during construction	10	14	16	18	21	19	17	19	23	26	29	20	231
Equity in earnings (losses) of unconsolidated subsidiaries	-	-	-	-	-	-	-	-	-	-	-	-	-
Other income	8	6	6	2	-	-	-	-	-	-	-	-	23
Less: Other expenses	(54)	(54)	(55)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(54)	(650)
Less: Income taxes below the line	71	70	70	69	68	68	68	68	68	68	68	68	822
Total Other Income (Expense), Net	1	4	7	6	7	5	3	6	9	12	15	7	82
Interest and Other Charges													
Interest on long-term debt	502	502	502	1,163	1,165	1,165	1,164	1,167	1,169	1,168	1,170	1,170	12,006
Short-term interest	16	-	-	54	108	102	97	73	61	74	80	67	733
Other interest	60	60	59	59	58	58	58	57	57	57	56	56	695
Amortization of debt items	23	23	23	34	34	34	34	34	34	34	34	34	374
Less: Interest income	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Allowance for borrowed funds used during construction	11	15	18	130	89	54	46	50	54	59	62	40	627
Total interest and other charges	590	570	567	1,179	1,276	1,306	1,306	1,282	1,267	1,274	1,278	1,287	13,181
Minority Interest	-	-	-	-	-	-	-	-	-	-	-	-	-
Preferred dividend requirements of subsidiaries	-	-	-	-	-	-	-	-	-	-	-	-	-
Income before Disc Ops, Change in Acctg Principles	3,072	1,949	1,981	1,915	2,035	3,065	3,783	3,729	2,099	2,199	3,228	5,951	35,006
Discontinued operations, net of tax	-	-	-	-	-	-	-	-	-	-	-	-	-
Change in accting principles, net of tax	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Income	3,072	1,949	1,981	1,915	2,035	3,065	3,783	3,729	2,099	2,199	3,228	5,951	35,006

Duke Energy Kentucky
Income Statement
DEK Electric Rate Case - 2006 Budget

	2006 Jan	2006 Feb	2006 Mar	2006 Apr	2006 May	2006 Jun	2006 Jul	2006 Aug	2006 Sep	2006 Oct	2006 Nov	2006 Dec	Total 12 Months
Operating Revenues													
Retail Revenues	19,711	18,750	18,466	16,613	18,223	21,481	23,363	24,377	19,324	17,526	17,451	19,884	235,168
Sales for Resale Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
Off System Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Transfer Revenue/Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Electric Revenues	2,135	2,947	3,458	1,293	1,054	463	338	477	405	1,260	1,091	597	15,518
Total Electric Revenues	21,846	21,697	21,924	17,906	19,276	21,945	23,701	24,853	19,729	18,786	18,542	20,482	250,686
Firm Sales	49,704	32,683	17,815	7,691	881	3,550	4,428	4,684	5,376	10,074	22,362	40,235	199,484
Transportation	521	511	437	345	253	217	199	203	207	238	307	431	3,869
Other Gas Revenues	37	50	43	37	27	31	27	24	21	43	43	34	419
Total Gas Revenues	50,262	33,243	18,296	8,073	1,161	3,798	4,655	4,911	5,604	10,355	22,713	40,700	203,772
Other Operating Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operating Revenues	72,108	54,940	40,219	25,979	20,438	25,742	28,356	29,764	25,333	29,141	41,255	61,181	454,458
Operating Expenses													
Fuel used in electric production	7,565	6,555	6,867	3,916	5,451	6,574	8,399	8,557	5,324	5,233	5,236	6,031	75,708
Purchased and exchanged power	1,216	865	819	5,057	1,224	2,788	3,017	2,787	2,210	1,508	1,554	1,831	24,874
Total Emission Allowances	600	735	786	247	529	394	392	702	768	482	465	380	6,479
Total Electric Cost of Goods Sold	9,381	8,154	8,472	9,220	7,204	9,756	11,807	12,046	8,302	7,222	7,255	8,242	107,060
Gas purchased	40,567	25,582	12,752	4,461	(722)	2,120	2,927	3,152	3,700	7,731	18,178	33,139	153,587
Other Operations & Maintenance Total	8,345	7,838	7,687	9,359	8,236	7,946	7,421	7,374	7,582	7,663	7,669	7,568	94,688
Depreciation	3,297	3,304	3,311	3,317	3,319	3,329	3,373	3,376	3,382	3,389	3,401	3,431	40,231
Property tax expense	644	644	644	644	644	644	644	644	644	644	644	644	7,730
Payroll tax expense	211	204	197	206	196	196	196	188	198	201	197	196	2,386
Revenue tax expense	1	-	-	1	-	-	1	5	-	1	-	-	8
Other tax expense	-	-	-	-	-	-	-	-	-	-	-	-	-
Taxes other than income taxes total	855	848	841	851	840	840	841	838	842	846	841	840	10,124
Total Operating Expenses	62,446	45,726	33,064	27,208	18,877	23,992	26,369	26,786	23,808	26,850	37,344	53,220	405,690
Pretax Operating Income	9,662	9,214	7,156	(1,229)	1,561	1,750	1,987	2,979	1,525	2,291	3,911	7,961	48,767
Income Taxes													
State Income Tax	592	563	420	(165)	29	37	50	121	19	72	186	466	2,391
Federal Income Tax	2,832	2,694	2,011	(792)	141	179	240	579	92	347	892	2,233	11,446
Income Taxes Total	3,423	3,256	2,431	(957)	170	216	290	700	111	420	1,078	2,700	13,837
Operating Income	6,239	5,958	4,725	(272)	1,390	1,534	1,698	2,278	1,415	1,871	2,833	5,261	34,930
Other Income (Expense), Net													
Allowance for equity funds used during construction	0	0	0	0	0	0	0	0	0	0	0	0	2
Equity in earnings (losses) of unconsolidated subsidiaries	-	-	-	-	-	-	-	-	-	-	-	-	-
Other income	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Other expenses	(38)	(36)	(39)	(38)	(108)	(107)	(116)	(108)	(108)	(109)	(107)	(136)	(1,051)
Less: Income taxes below the line	61	60	61	61	88	88	91	88	88	89	88	100	964
Total Other Income (Expense), Net	(22)	(24)	(22)	(23)	20	19	24	20	20	21	19	37	88
Interest and Other Charges													
Interest on long-term debt	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	1,312	15,743
Short-term interest	-	-	-	-	-	-	-	-	-	-	-	-	-
Other interest	(193)	(212)	(213)	(212)	(186)	(143)	(126)	(140)	(129)	(118)	(121)	(109)	(1,901)
Amortization of debt items	36	36	36	36	36	36	36	36	36	36	36	36	430
Less: Interest income	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Allowance for borrowed funds used during construction	57	74	93	114	132	98	60	68	77	85	88	53	999
Total interest and other charges	1,098	1,061	1,042	1,022	1,030	1,107	1,163	1,140	1,142	1,144	1,139	1,186	13,273
Minority Interest	-	-	-	-	-	-	-	-	-	-	-	-	-
Preferred dividend requirements of subsidiaries	-	-	-	-	-	-	-	-	-	-	-	-	-
Income before Disc Ops, Change in Acctg Principles	5,119	4,873	3,661	(1,317)	380	446	560	1,158	293	747	1,713	4,112	21,745
Discontinued operations, net of tax	-	-	-	-	-	-	-	-	-	-	-	-	-
Change in accting principles, net of tax	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Income	5,119	4,873	3,661	(1,317)	380	446	560	1,158	293	747	1,713	4,112	21,745

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(9)(e)

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807 KAR 5:001, SECTION 10(9)(e)

Description of Filing Requirement:

A statement of attestation signed by the utility's chief officer in charge of Kentucky operations which shall provide:

1. That the forecast utilized in Case No. 2006-00172 by Duke Energy Kentucky is, in my opinion, reasonable, reliable, made in good faith and that all basic assumptions used in the forecast have been identified and justified; and

2. That the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management of Duke Energy Kentucky; and

3. That productivity and efficiency gains are included in the forecast.

Response: See attached.

Sponsoring Witness: Sandra P. Meyer

AFFIDAVIT OF SANDRA P. MEYER

State of Ohio)
) SS:
County of Hamilton)

Now comes Sandra P. Meyer, President of The Cincinnati Gas & Electric Company d/b/a Duke Energy Ohio ("Duke Energy Ohio") and President of The Union Light, Heat and Power Company d/b/a Duke Energy Kentucky ("Duke Energy Kentucky"), and as required by 807 KAR 5:001, Section 10(9)(e), hereby attests as follows:

1. the forecast used in Case No. 2006-00172 by Duke Energy Kentucky is reasonable, reliable, made in good faith and that all basic assumptions used in the forecast have been identified and justified; and

2. the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management, or an identification and explanation for any differences that exist; and

3. productivity and efficiency gains are included in the forecast; and

4. merger savings are reflected in Duke Energy Kentucky's proposed rates through the proposed continuation of the merger savings sharing mechanism, as required by the Commission's November 29, 2005 Order in Case No. 2005-00228.

Further affiant sayeth naught.

Sandra P. Meyer, Affiant

Sworn and subscribed before me by Sandra P. Meyer on this 26th day of May, 2006.

Notary Public

My Commission Expires:

JOHN J. FINNIGAN, JR. Attorney at Law
NOTARY PUBLIC, STATE OF OHIO
My commission has no expiration
date. Section 147.03 O.R.C.

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(9)(f)

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807 KAR 5:001, SECTION 10(9)(f)

Description of Filing Requirement:

For each major construction project which constitutes five (5) percent or more of the annual construction budget within the three (3) year forecast the following information shall be filed:

1. The date the project was started or estimated starting date;
2. The estimated completion date;
3. The total estimated cost of construction by year exclusive and inclusive of allowance for funds used during construction ("AFUDC") or interest during construction credit; and
4. The most recent available total costs incurred exclusive and inclusive of AFUDC or interest during construction credit.

Response:

See attached.

Sponsoring Witness: Jim L. Stanley / John J. Roebel

Duke Energy Kentucky
Case No. 2006-00172
Major Construction Projects
Constituting 5% or More of Annual Budget
Years 2006-2008

Line No.	Project ID / Description	*Actual or* Projected Start Date	*Projected* Completion Date	Estimated Costs Including AFUDC 2006	Estimated Costs Including AFUDC 2007	Estimated Costs Including AFUDC 2008	Estimated Costs Excluding AFUDC 2006	Estimated Costs Excluding AFUDC 2007	Estimated Costs Excluding AFUDC 2008	Actual Costs *To Date* incl AFUDC	Actual Costs *To Date* excl AFUDC
1	*EB201294 - Install Lndfl Cell P-15 & P-16*	Jan-05	Dec-06	$ 4,611,059	$ 22	$ -	$ 4,487,866	$ -	$ -	$ 317,563	$ 313,706
2	MF3056 - MFS-6 LNCFSII	Dec-04	Jun-06	3,876,634	-	-	*3,844,070*	-	-	1,625,712	1,618,323
3	WG0191 - WGS-CT1 Major "C" Overhaul #1	Dec-04	Jun-06	3,939,060	-	-	3,663,527	-	-	2,879,638	2,787,683
4	WG0244 - WGS-CT4 Major "C" Overhaul #1	Jan-07	Jun-08	-	2,748,667	14,616,905	-	2,616,698	14,278,773	(6,052)	(6,052)
5	310ZNB - ZULH&P NEW BUSINESS SOUTH AREA	Jan-06	Dec-50	4,975,959	5,094,011	5,144,598	4,975,959	5,094,011	5,144,598	2,219,097	2,215,948
	TOTAL			$ 17,402,712	$ 7,842,700	$ 19,761,503	$ 16,971,423	$ 7,710,709	$ 19,423,371	$ 7,035,977	$ 6,929,608

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(9)(g)

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807 KAR 5:001, SECTION 10(9)(g)

Description of Filing Requirement:

For all construction projects which constitute less than five (5) percent of the annual construction budget within the three (3) year forecast, the utility shall file an aggregate of the information requested in paragraph (f)3 and 4 of this subsection

Response:

See attached.

Sponsoring Witness: Jim L. Stanley / John J. Roebel

Duke Energy Kentucky

Case No. 2006-00172

Major Construction Projects
Constituting Less Than 5% of Annual Budget
Years 2006-2008

Line No.	Project ID / Description	Actual or Projected Start Date	Projected Completion Date	Estimated Costs Including AFUDC 2006	Estimated Costs Including AFUDC 2007	Estimated Costs Including AFUDC 2008	Estimated Costs Excluding AFUDC 2006	Estimated Costs Excluding AFUDC 2007	Estimated Costs Excluding AFUDC 2008	Actual Costs To Date incl AFUDC	Actual Costs To Date excl AFUDC
1	Sum of all projects not included on FR 10(9)(f)			$ 24,475,848	$ 22,920,696	$ 19,791,002	$ 24,125,258	$ 22,429,331	$ 19,214,095	$ 27,907,360	$ 27,136,042

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(9)(h)

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807 KAR 5:001, SECTION 10(9)(h)

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include the following information:

1. Operating income statement (exclusive of dividends per share or earnings per share);
2. Balance sheet;
3. Statement of cash flows;
4. Revenue requirements necessary to support the forecasted rate of return;
5. Load forecast including energy and demand (electric);
6. Access line forecast (telephone);
7. Mix of generation (electric);
8. Mix of gas supply (gas);
9. Employee level;
10. Labor cost changes;
11. Capital structure requirements;
12. Rate base;
13. Gallons of water projected to be sold (water);
14. Customer forecast (gas, water);
15. MCF sales forecasts (gas);
16. Toll and access forecast of number of calls and number of minutes (telephone); and
17. A detailed explanation of any other information provided;

Response: Items 6, 13, 16, and 17 are not applicable to Duke Energy Kentucky. For all other items see attached.

Sponsoring Witness:

Brian P. Davey, Items 1, 2, 3, 4, 8, 9, 10, 12, 14 and 15

Douglas F. Esamann, Item 7

Lynn J. Good, Item 11

Dr. Richard D. Stevie, Item 5

Duke Energy Kentucky
Case No. 2006-00172
Projected Income Statement 2006-2008

Line No.	Description	2006	2007	2008
1	Operating Revenue			
2	Electric Revenue	$249,143	$289,946	$291,576
3	Gas Revenue	164,021	182,553	170,457
4	Other Revenue	-	-	-
5	Total Operating Revenue	$413,164	$472,499	$462,033
6	Operating Expenses			
7	Fuel & Purchased Power	$108,869	$127,459	$128,021
8	Gas Purchased	120,612	133,579	119,993
9	Operation & Maintenance	116,731	118,602	117,102
10	Depreciation & Amortization	41,138	43,990	45,374
11	Taxes Other Than Income	10,138	10,823	11,463
12	Operating Expenses before Income Tax	$397,488	$434,453	$421,953
13	Pre-Tax Operating Income	$15,676	$38,046	$40,080
14	Other Income	$2,898	$636	$1,970
15	Interest Expense	$16,613	$15,207	$17,398
16	State Income Taxes	$0	$1,257	$1,358
17	Federal Income Taxes	292	7,063	7,644
18	Total Income Taxes	$292	$8,320	$9,002
19	Income Available for Common Dividends	$1,669	$15,155	$15,650
20	Average Common Equity	$328,715	$345,393	$350,183
21	Earned Return	0.51%	4.39%	4.47%

Duke Energy Kentucky
Case No. 2006-00172
Projected Balance Sheet 2006-2008

Line No.	Description	2006	2007	2008
1	**Assets**			
2	Utility plant in service	$1,444,589	$1,494,120	$1,553,324
3	Construction work in progress	3,375	6,437	4,681
4	Total Utility Plant	$1,447,964	$1,500,557	$1,558,005
5	Non-regulated property, plant, and equipment	$0	$0	$0
6	Accumulated depreciation	632,705	671,232	707,624
7	Net Property, Plant, and Equipment	$815,259	$829,325	$850,381
8	Current Assets	$81,260	$80,856	$76,738
9	Other Assets	$14,814	$16,517	$17,411
10	Total Assets	$911,333	$926,698	$944,530
	Liabilities			
11	Total Current Liabilities	$136,606	$142,369	$158,135
12	Long-term debt	$264,834	$263,603	$262,120
13	Accumulated deferred income taxes	132,614	134,412	134,076
14	Unamortized investment tax credits	7,333	6,549	5,772
15	Other	31,963	31,927	31,899
16	Total Non-Current Liabilities	$436,744	$436,491	$433,867
17	Total Common Stock Equity	$337,983	$347,838	$352,528
18	Total Liabilities	$911,333	$926,698	$944,530

Duke Energy Kentucky
Case No. 2006-00172
Projected Cash Flow Statement 2006-2008

Line No.	Description	2006	2007	2008
1	Net Income	$1,669	$15,155	$15,650
2	Other Operating Activities	46,558	52,132	56,543
3	*Cash from Operating Activities*	48,227	67,287	72,193
4	Financing Activities			
5	Change in contributed capital	$139,855	$0	$0
6	Change in short-term debt	13,531	(2,594)	6,779
7	Issuance of long-term debt	175,322	-	20,000
8	Change in non-current capital leases	-	(1,304)	(1,545)
9	Redemption of long-term debt	(14,905)	(1)	(20,000)
10	Dividends on common stock	-	(5,300)	(10,960)
11	Cash from Financing Actitivies	313,803	(9,199)	(5,726)
12	Investing Activities			
13	Construction Expenditures (net of AFUDC)	($65,051)	($58,088)	($66,467)
14	Acquisitions and other investments	(306,855)	-	-
15	Cash from Investing Actitivies	(371,906)	(58,088)	(66,467)
16	Net Increase/(Decrease) in Cash	($9,876)	$0	$0

Duke Energy Kentucky
Case No. 2006-00172
Revenue Requirements 2006-2008

Line No.	Description	2006	2007	2008

Refer to FR 10(9)(h)(1) for revenue requirements.

Duke Energy Kentucky
Case No. 2006-00172
Load Forecast 2006-2008

Line No.	Description	2006	2007	2008
1	KW Demand - Coincident Peak			
2				
3	January	748	753	758
4	February	699	703	708
5	March	658	663	667
6	April	598	602	606
7	May	700	709	714
8	June	860	870	877
9	July	901	912	919
10	August	901	912	919
11	September	809	819	825
12	October	618	626	630
13	November	663	668	672
14	December	720	725	730
15				
16	KWH Sales			
17				
18	January	359,736	364,699	367,053
19	February	336,091	340,765	342,955
20	March	315,069	319,484	321,494
21	April	294,749	298,870	300,724
22	May	284,353	288,351	290,118
23	June	323,856	328,405	330,448
24	July	367,370	372,428	374,832
25	August	378,589	383,773	386,259
26	September	361,794	366,753	369,094
27	October	298,520	302,549	304,447
28	November	291,784	295,715	297,575
29	December	340,176	344,703	346,924

Duke Energy Kentucky
Case No. 2006-00172
Mix of Generation 2006-2008

Line No.	Description	2006	2007	2008
1	Coal	3,575,290	3,352,297	3,625,546
2	Natural Gas	47,061	42,563	41,673
3	Oil	0	0	0
4	Total Generation (MWH)	3,622,351	3,394,860	3,667,219

Duke Energy Kentucky
Case No. 2006-00172
Mix of Gas Supply 2006-2008

Line No.	Description	2006	2007	2008
1	Columbia Gas Trans - No Notice	1,041,661	1,041,661	1,041,661
2	Undetermined	11,100,123	11,064,604	11,220,380
3	Propane - Air	33,000	33,000	33,000
4	Total Supply - MCF	12,174,784	12,139,265	12,295,041
5				
6				
7				
8				
9	Columbia Gas Trans - No Notice	$ 8,883,225	$ 10,537,998	$ 9,425,272
10	Undetermined	141,803,413	120,161,166	106,469,057
11	Propane - Air	203,039	203,039	203,039
12	Demand Costs	4,986,508	4,837,183	5,074,755
13	Total Cost	$ 155,876,185	$ 135,739,386	$ 121,172,123

Duke Energy Kentucky
Case No. 2006-00172
Number of Employees 2006-2008

Line No.	Description	2006	2007	2008
1	Number of employees	309	309	309

This count includes only direct employees of ULH&P.

Duke Energy Kentucky
Case No. 2006-00172
Labor Cost Changes 2006-2008

Line No.	Description	2006	2007	2008
1	Total Labor Costs:			
2				
3	Gas O&M Expense	$7,115,990	$7,369,200	$7,663,968
4	Electric O&M Expense	21,787,117	22,578,629	23,481,774
5	Total O&M	28,903,107	29,947,829	31,145,742
6				
7	Gas Capital	3,457,864	3,486,446	3,530,977
8	Electric Capital	6,264,755	5,975,434	6,241,256
9	Non-jurisdictional Capital	0	0	0
10	Total Capital	9,722,619	9,461,880	9,772,233
11				
12	Total	$38,625,726	$39,409,709	$40,917,975

* Includes direct and indirect labor costs.

Duke Energy Kentucky
Case No. 2006-00172
Capital Structure Requirements 2006-2008

Line No.	Description	2006	2007	2008

Refer to FR 10(9)(h)(2) and 10(9)(h)(3).

Duke Energy Kentucky
Case No. 2006-00172
Rate Base 2006-2008

Line No.	Description	2006	2007		2008
1	Rate Base at December 31, __	$604,587,184	$590,909,461	(A)	$598,430,417

(A) Source: Schedule B-1.

Duke Energy Kentucky
Case No. 2006-00172
Customer Forecast 2006-2008

Line No.	Description	2006	2007	2008
1	Residential	118,154	119,597	120,672
2	Commercial	13,119	13,364	13,546
3	Industrial	397	397	397
4	Other	1,277	1,297	1,307
5	Total Electric Retail	132,947	134,655	135,922
6				
7	Residential	86,244	87,667	88,867
8	Commercial	6,936	6,958	7,063
9	Industrial	237	235	238
10	Other	382	381	386
11	Total Full Requirements	93,799	95,241	96,554
12				
13	Transportation			
14	Commercial	24	24	24
15	Industrial	45	45	45
16	Other	9	9	9
17	Total Transportation	78	78	78
18				
19	Total Gas Retail	93,877	95,319	96,632

Duke Energy Kentucky
Case No. 2006-00172
MCF Sales Forecast 2006-2008

Line No.	Description	2006	2007	2008
1	Residential	7,512,511	7,447,363	7,525,118
2	Commercial	3,262,209	3,310,298	3,349,543
3	Industrial	598,537	562,443	578,585
4	Other	512,227	517,091	521,544
	Interdepartmental	6,999	6,999	6,999
5	Total Retail	11,892,483	11,844,194	11,981,789
6	Transportation			
7	Commercial	414,229	415,445	425,331
8	Industrial	1,583,321	1,484,859	1,571,482
9	Other	269,642	272,204	274,546
10	Total Transportation	2,267,192	2,172,508	2,271,359
11	Total Sales	14,159,675	14,016,702	14,253,148

DUKE ENERGY KENTUCKY
CASE NO. 2006-00172
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 10(9)(i)

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807 KAR 5:001, SECTION 10(9)(i)

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission or Federal Communications Commission audit reports.

Response:

See attached.

Sponsoring Witness: Dwight L. Jacobs

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D.C. 20426

ATT'N
RECEIVED
D. R. HERCHE
OCT 21 1994
FILE:
RETURN TO:

In Reply Refer To:
OCA-DOA
Docket No. FA93-64-000

OCT 17 1994

The Union Light, Heat and Power Company
Attention: Mr. Daniel R. Herche
Controller
139 East Fourth Street
Cincinnati, OH 45202

Ladies and Gentlemen:

The Division of Audits of the Office of Chief Accountant has examined the books and records of The Union Light, Heat and Power Company for the period January 1, 1990 through December 31, 1992. The purpose of the examination was to evaluate your Company's compliance with Commission accounting and reporting regulations contained in the Uniform System of Accounts, Annual Report FERC Form No. 1, and the related regulations. The examination included selective tests of the accounting records, review of the internal control structure, and other tests and procedures considered necessary under the circumstances.

The Division of Audits recommended corrective actions on certain findings of noncompliance with the Commission's accounting, financial reporting, and/or related regulations. The enclosed audit report describes the findings, recommendations, and correcting entries. By letter dated September 20, 1994, your Company agreed to adopt the recommended corrective actions. I hereby approve and direct the recommended corrective actions.

The Kentucky Public Service Commission did not respond with any objections to the foregoing matters.

The Commission delegated authority to act in this matter to the Director, Division of Audits under 18 C.F.R. § 375.303. This letter order constitutes final agency action on the corrective actions approved and directed in this report. Within 30 days of the date of this order, your Company may file a request for rehearing by the Commission under 18 C.F.R. § 385.713.

This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention.

Sincerely,

Joseph A. Frangipane
Joseph A. Frangipane
Director, Division of Audits

Enclosure

Results of the Examination

of the

Books and Records

of

The Union Light, Heat and Power Company
Docket No. FA93-64-000

For the Period

1/1/90 through 12/31/92

Conducted by

Division of Audits
Office of Chief Accountant
Federal Energy Regulatory Commission

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No.	Description	Page

COMPLIANCE EXCEPTIONS

COMPLIANCE EXCEPTIONS

The Union Light, Heat and Power Company (Company) agreed to adopt the recommended corrective actions in the following compliance matters:

1. Accounting for PCB Disposal Costs

The Company improperly accounted for costs associated with the disposal of Polychlorinated Biphenyl (PCB)-contaminated materials removed from plant equipment.

Background of Issue

The Company undertook a program to dispose of PCB-contaminated materials and equipment (transformers, capacitors, etc.) in accordance with guidelines issued by the Environmental Protection Agency. As a result, the Company retired certain of the PCB-contaminated equipment. Also, it retrofilled 1/ other equipment and later reused the equipment.

For accounting purposes, the Company classified the expenses elated to PCB cleanup and disposal either in maintenance expense accounts or as cost of removal in Account 108, Accumulated Provision for Depreciation of Electric Utility Plant. During the period 1990 through 1992 the Company recorded in Account 108 about $62,504 incurred in the PCB disposal program, for cleanup and disposal costs related to certain equipment that was not retired, but held for subsequent use.

Discussion of Accounting Requirements

Electric Plant Instruction No. 10(c) of the Uniform System of Accounts states, in part:

> (3) When a minor item of depreciable property is replaced independently of the retirement unit of which it is a part, the cost of replacement shall be charged to the maintenance account appropriate for the item . . . .

1/ Retrofilling essentially consists of draining all PCP contaminated dielectric fluids from installed equipment, flushing the equipment with a non-PCB contaminated fluid, and refilling the equipment with a non-PCB dielectric coolant.

Also, Operating Expense Instruction No. 2A provides a list of maintenance work operations applicable generally to utility plant. Two of the items on the list are as follows:

> 3. Work performed specifically for the purpose of preventing failure, restoring serviceability or maintaining life of the plant.
>
> 8. Replacing or adding minor items of plant which do not constitute a retirement unit.

The instructions to Account 570, Maintenance of Station Equipment, state in part:

> This account shall include the cost of labor, materials used and expenses incurred in maintenance of station equipment the book cost of which is includible in account 353, Station Equipment.

The instructions to Account 595, Maintenance of Line Transformers, provide similar requirements related to line transformer equipment.

Under the circumstances present here, the costs incurred to retrofill the equipment were properly assigned to maintenance expense. Therefore, the Company should have recorded the costs incurred in the retrofilling of certain equipment in Accounts 570 and 595, as appropriate.

Recommendations

We recommend the Company:

(1) revise accounting procedures to ensure it accounts for the cost of future PCB cleanup operations in accordance with the requirements of the Uniform System of Accounts;

(2) review its records of PCB disposal costs incurred prior to 1990 for similar amounts improperly charged to Account 108; and

(3) record a correcting entry by charging maintenance expense and crediting Account 108 with any costs related to retrofilling of PCB contaminated equipment.

The Company shall submit a copy of the correcting entry to the Office of Chief Accountant.

2. **Accounting for Deferred Income Taxes**

The Company did not record certain deferred income taxes in its accounts related to book/tax differences collected in wholesale rate levels.

Background of Issue

The Company did not record deferred income taxes related to book/tax differences covering the following items:

- Rental income
- Gift certificates
- Other small items

The Company did not receive provisions for normalized income taxes for the previously mentioned items in establishing retail rates. However, the Company's rates subject to the jurisdiction of FERC included a provision for income taxes based on normalization for all book/tax differences.

During 1993 the Company adopted the provisions of Statement of Financial Accounting Standard (SFAS) No. 109, Accounting for Income Taxes. Upon adoption of SFAS 109, the Company established deferred income taxes for the previously mentioned book/tax differences. At the same time it recorded a regulatory asset in Account 182.3, Other Regulatory Assets, for the book/tax effects subject to FERC jurisdiction.

Discussion of Accounting Requirements

General Instruction No. 18, Comprehensive Interperiod Income Tax Allocation, of the Uniform System of Accounts requires a utility to establish deferred income taxes to the extent that normalized income taxes are provided in the rate levels established by each regulatory jurisdiction.

Prior to 1993, the Company should have applied comprehensive interperiod income tax allocation procedures for the effect of any book/tax differences related to rates subject to FERC jurisdiction. Upon adoption of SFAS 109, the Company should not have established a regulatory asset for the tax effects of any amounts previously subjected to FERC rates.

Recommendations

We recommend the Company:

(1) revise procedures to ensure that it records deferred income taxes consistent with the provisions of General Instruction No. 18; and

(2) record a correcting entry to remove any regulatory asset and to charge income tax expense for any amounts previously provided for under rates subject to FERC jurisdiction.

The Company shall submit a copy of the correcting entry to the Office of Chief Accountant.

$115,000,000

THE UNION LIGHT, HEAT AND POWER COMPANY

5.75% Debentures Due 2016
6.20% Debentures Due 2036

OFFERING MEMORANDUM
MARCH 7, 2006

SOLE BOOK-RUNNER

KEYBANC CAPITAL MARKETS

CO-MANAGER

LASALLE CAPITAL MARKETS

OFFERING MEMORANDUM

$115,000,000

THE UNION LIGHT, HEAT AND POWER COMPANY

5.75% Debentures due 2016
6.20% Debentures due 2036

We are offering $115,000,000 aggregate principal amount of Debentures with $50,000,000 principal amount of 5.75% Debentures due 2016 (the "Series A") and $65,000,000 principal amount of 6.20% Debentures due 2036 (the "Series B" and together with Series A, the "Debentures"). The Debentures will mature on March 10, 2016 and March 10, 2036, respectively. We will pay interest on the Debentures on March 10 and September 10 of each year, beginning on September 10, 2006.

The Debentures will be unsecured and will rank equally with all of our other unsecured senior indebtedness from time to time outstanding. We may redeem some or all of the Debentures at any time by paying the sum of the principal amount of the Debentures, the applicable "make whole" amount, if any, and accrued and unpaid interest. See "Description of the Debentures—Optional Redemption by ULH&P" in this Offering Memorandum.

THE DEBENTURES HAVE NOT BEEN REGISTERED UNDER THE SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT"), OR ANY STATE SECURITIES LAWS AND, UNLESS SO REGISTERED, MAY NOT BE OFFERED OR SOLD EXCEPT PURSUANT TO AN EXEMPTION FROM, OR IN A TRANSACTION NOT SUBJECT TO, THE REGISTRATION REQUIREMENTS OF THE SECURITIES ACT AND APPLICABLE STATE SECURITIES LAWS. ACCORDINGLY THE DEBENTURES OFFERED HEREBY ARE BEING OFFERED AND SOLD ONLY TO QUALIFIED INSTITUTIONAL BUYERS, AS DEFINED IN AND IN RELIANCE ON RULE 144A UNDER THE SECURITIES ACT.

	Offering Price(1)	Initial Purchasers' Discount	Proceeds to Company Before Expenses
Per Series A	99.940%	0.65%	99.290%
Series A Total	$49,970,000.00	$325,000.00	$49,645,000.00
Per Series B	99.434%	0.875%	98.559%
Series B Total	$64,632,100.00	$568,750.00	$64,063,350.00
Total	$114,602,100.00	$893,750.00	$113,708,350.00

(1) Plus accrued interest, if any from March 10, 2006.

The Initial Purchasers expect to deliver the Debentures on or about March 10, 2006, through the book entry facilities of The Depository Trust Company.

SOLE BOOK-RUNNER

KEYBANC CAPITAL MARKETS

CO-MANAGER

LASALLE CAPITAL MARKETS

March 7, 2006

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(This page has been left blank intentionally.)

The Initial Purchasers participating in this offering may engage in transactions that stabilize, maintain or otherwise affect the price of the Debentures. For a description of these activities, see "Plan of Distribution."

The offering is being made in reliance upon an exemption from registration under the Securities Act for an offer and sale of securities which does not involve a public offering. Each purchaser of the Debentures offered hereby in making its purchase will be deemed to have made certain acknowledgments, representations and agreements as set forth under "Transfer Restrictions." The Debentures have not been registered under the Securities Act or any state securities laws and, unless so registered, may not be offered or sold except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act and applicable state securities laws. Prospective purchasers are hereby notified that sellers of the Debentures may be relying on the exemption from the provisions of Section 5 of the Securities Act provided by Rule 144A. For certain restrictions on resales, see "Transfer Restrictions."

This Offering Memorandum is submitted on a highly confidential basis to a limited number of institutional investors for informational use solely in connection with the consideration of the purchase of the Debentures. Its use for any other purpose is not authorized. It may not be copied or reproduced in whole or in part nor may it be distributed or any of its contents be disclosed to anyone other than the prospective investors to whom it is submitted.

In making an investment decision regarding the Debentures offered hereby, prospective investors must rely on their own examination of the Company and the terms of the offering, including the merits and risks involved. The contents of this Offering Memorandum are not to be construed as legal, business or tax advice. Each prospective investor should consult its own counsel, accountant and other advisors as to legal, tax, business, financial and related aspects of a purchase of the Debentures. Nothing contained in this Offering Memorandum is, or shall be relied upon as, a promise or representation by the Initial Purchasers as to the past or the future.

The distribution of the Offering Memorandum and the offer or sale of the Debentures may be restricted by law in certain jurisdictions. Persons into whose possession this Offering Memorandum or any of the Debentures comes must inform themselves about, and observe, any such restrictions. See "Plan of Distribution" and "Transfer Restrictions." Neither the Company, the Initial Purchasers nor any of their respective representatives are making any representation to any offeree or purchaser of the Debentures regarding the legality of an investment therein by such offeree or purchaser under appropriate legal investment or similar laws. Each prospective purchaser of the Debentures must comply with all applicable laws and regulations in force in any jurisdiction in which it purchases, offers or sells the Debentures or possesses or distributes this Offering Memorandum and must obtain any consent, approval or permission required by it for the purchase, offer or sale by it of the Debentures under the laws and regulations in force in the jurisdiction to which it is subject or in which it makes such purchases, offers or sales, and none of the Company (or any stockholder thereof) or the Initial Purchasers shall have any responsibility therefor.

All inquiries relating to this Offering Memorandum and the offering contemplated herein should be directed to the Initial Purchasers. Prospective investors may obtain such additional information from the Initial Purchasers or the Company as they may reasonably require in connection with the decision to purchase any of the Debentures.

The Debentures described herein have not been registered with, recommended by or approved by the Securities and Exchange Commission (the "Commission") or any other federal or state securities commission or regulatory authority, nor has any such commission or regulatory authority passed upon the accuracy or adequacy of this Offering Memorandum. Any representation to the contrary is a criminal offense.

The offering can be withdrawn at any time before the closing and is specifically made subject to the terms described in this Offering Memorandum and the Purchase Agreement (described in "Plan of Distribution").

We have agreed that, for so long as any Debentures remain outstanding or during any period in which the Company is not subject to Section 13 or 15(d) under the Exchange Act, we will furnish to the holders and prospective investors, upon their request, the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act. Any such request should be directed to the address referred to under "Available Information."

NOTICE TO NEW HAMPSHIRE INVESTORS

NEITHER THE FACT THAT A REGISTRATION STATEMENT OR AN APPLICATION FOR A LICENSE HAS BEEN FILED UNDER CHAPTER 421-B OF THE NEW HAMPSHIRE UNIFORM SECURITIES ACT WITH THE SECRETARY OF STATE OF NEW HAMPSHIRE NOR THE FACT THAT A SECURITY IS EFFECTIVELY REGISTERED OR A PERSON IS LICENSED IN THE STATE OF NEW HAMPSHIRE CONSTITUTES A FINDING BY THE SECRETARY OF STATE THAT ANY DOCUMENT FILED UNDER RSA 421-B IS TRUE, COMPLETE AND NOT MISLEADING. NEITHER ANY SUCH FACT NOR THE FACT THAT AN EXEMPTION OR EXCEPTION IS AVAILABLE FOR A SECURITY OR A TRANSACTION MEANS THAT THE SECRETARY OF STATE HAS PASSED IN ANY WAY UPON THE MERITS OR QUALIFICATIONS OF, OR RECOMMENDED OR GIVEN APPROVAL TO, ANY PERSON, SECURITY OR TRANSACTION. IT IS UNLAWFUL TO MAKE, OR CAUSE TO BE MADE, TO ANY PROSPECTIVE PURCHASER, CUSTOMER, OR CLIENT ANY REPRESENTATION INCONSISTENT WITH THE PROVISIONS OF THIS PARAGRAPH.

The Debentures will be available initially only in book-entry form. The Company expects that the Debentures sold to Qualified Institutional Buyers will be issued in the form of Global Debentures. The Global Debentures will be deposited with, or on behalf of, the Depository and registered in its name or in the name of Cede & Co., its nominee. Beneficial interests in the Global Debentures will be shown on, and transfers thereof will be effected through, records maintained by the Depository and its Participants (as defined herein). See "Description of the Debentures—*Global Securities*" for further discussion of these matters and for definitions of certain of the defined terms used in this paragraph.

AVAILABLE INFORMATION

Unless we have indicated otherwise, or the context otherwise requires, references in this Offering Memorandum to "ULH&P," "Union Light" "the Company," "we," "us" and "our" or similar terms are to The Union Light, Heat & Power Company.

ULH&P previously filed reports and other information with the Commission pursuant to the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Certain information concerning directors and officers, their remuneration, and any material interest of such persons in transactions with ULH&P, as of particular dates, was disclosed in ULH&P's Annual Report on Form 10-K filed on March 2, 2006, with the Commission for the period ending December 31, 2005. Such reports and other information can be inspected and copied at the public reference facilities maintained by the Commission. The Commission maintains a Web site that contains reports, proxy and information statements and other information regarding issuers, such as ULH&P, that file electronically with the Commission and the address of such Web site is http://www.sec.gov. Copies of such material can also be obtained at prescribed rates from the Public Reference Section of the Commission at its principal office at 100 F Street, NE, Washington, D.C. 20549. Such material can also be inspected at the offices of the New York Stock Exchange.

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LEGAL MATTERS

The validity of the Debentures will be passed upon for us by Thompson Hine LLP, Cincinnati, Ohio. Davis Polk & Wardwell will pass upon certain matters for the Initial Purchasers. Davis Polk & Wardwell has acted as counsel in some matters for us and some of our affiliates.

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The financial statements and financial statement schedule as of December 31, 2005 and 2004, and for each of the three years in the period ended December 31, 2005, incorporated in this offering memorandum by reference from the Company's Annual Report on Form 10-K for the year ended December 31, 2005, have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report dated February 17, 2006 relating to the financial statements and financial statement schedule of the Company (which report expresses an unqualified opinion on the Company's financial statements and includes an explanatory paragraph referring to the Company's adoption of Financial Accounting Standards Board Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" in 2005 and adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," in 2003) which is incorporated herein by reference.

As of January 1, 2006, ULH&P ceased to be subject to the reporting requirements of Section 13(a) or 15(d) of the Exchange Act. ULH&P is considering discontinuing filing reports and other information with the Commission under such sections.

The principal executive and business office of the Company is located at 139 East Fourth Street, Cincinnati, Ohio 45202 (telephone 513-421-9500).

Each purchaser of the Debentures from the Initial Purchasers will be furnished with a copy of this Offering Memorandum and any related amendments or supplements to this Offering Memorandum. Each person receiving this Offering Memorandum acknowledges that (i) such person has been afforded an opportunity to request from the Company and to review and has received, all additional information considered by it to be necessary to verify the accuracy and completeness of the information herein, (ii) such person has not relied on the Initial Purchasers or any person affiliated with the Initial Purchasers in connection with its investigation of the accuracy of such information or its investment decision and (iii) except as provided pursuant to (i) above, no person has been authorized to give any information or to make any representation concerning the Debentures offered hereby other than those contained herein, and, if given or made, such other information or representation should not be relied upon as having been authorized by the Company or the Initial Purchasers. While any Debentures remain outstanding, ULH&P will make available, upon request, to any beneficial owner and any prospective purchaser of Debentures the information required pursuant to Rule 144A(d)(4) under the Securities Act during any period in which ULH&P is not subject to Section 13 or 15 (d) of the Exchange Act. Any such request should be directed to the Vice President and Treasurer, The Union Light, Heat and Power Company, 139 East Fourth Street, Cincinnati, Ohio 45202 (telephone 513-421-9500)

INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

We are "incorporating by reference" certain information we filed with the Commission, which means that we are disclosing important information to you by referring you to those documents. The *information incorporated by reference is an important part* of this Offering Memorandum. We hereby incorporate by reference the documents listed below and any future filings made with the Commission under Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act after the date of this Offering Memorandum until we sell all of the Debentures and any such document shall become a part hereof from the date of filing of such document:

- Current Report on Form 8-K dated January 31, 2006; and
- Annual Report on Form 10-K for the year ended December 31, 2005.

ULH&P hereby undertakes to provide without charge to each person to whom a copy of this Offering Memorandum has been delivered, on the written or oral request of any such person, a copy of any or all of the documents referred to above which have been or may be incorporated in this Offering Memorandum by reference, other than exhibits to such documents. You may request a copy of these filings at no cost, by writing or telephoning the office of Wendy L. Aumiller, Vice President and Treasurer, The Union Light Heat & Power Company, 139 East Fourth Street, Cincinnati, Ohio 45202, telephone number (513) 421-9500.

STATEMENT AND, IN EACH CASE, IN ACCORDANCE WITH THE APPLICABLE SECURITIES LAWS OF ANY STATE OF THE UNITED STATES OR ANY OTHER APPLICABLE JURISDICTION; AND

(3) AGREES THAT IT WILL DELIVER TO EACH PERSON TO WHOM THIS DEBENTURE OR AN INTEREST HEREIN IS TRANSFERRED A NOTICE SUBSTANTIALLY TO THE EFFECT OF THIS LEGEND.

THE INDENTURE CONTAINS A PROVISION REQUIRING THE TRUSTEE TO REFUSE TO REGISTER ANY TRANSFER OF THIS DEBENTURE IN VIOLATION OF THE FOREGOING.

(5) The purchaser represents and covenants that it is not, and is not acquiring the Debentures with the assets of, or for or on behalf of, and will not sell or otherwise transfer the Debentures to, any employee benefit plan (as defined in Section 3(3) of the Employee Retirement Income Security Act of 1974, as amended ("ERISA")) or other arrangement that is subject to ERISA or Section 4975 of the Code (a "Plan") or any entity whose underlying assets include assets of a Plan pursuant to 29 C.F.R. Section 2510.3-101 or otherwise, except to the extent that the acquisition and holding of the Debentures:

(a)(i) are made solely with the assets of a bank collective investment fund and (ii) satisfy the requirements and conditions of Prohibited Transaction Class Exemption 91-38 issued by the Department of Labor;

(b)(i) are made solely with assets of an insurance company pooled separate account and (ii) satisfy the requirements and conditions of Prohibited Transaction Class Exemption 90-1 issued by the Department of Labor;

(c)(i) are made solely with assets managed by a qualified professional asset manager and (ii) satisfy the requirements and conditions of Prohibited Transaction Class Exemption 84-14 issued by the Department of Labor;

(d) are made solely with assets of a governmental plan (as defined in Section 3(32) *of ERISA) which is not subject to the provisions of Section 401 of the Code;*

(e)(i) are made solely with assets of an insurance company general account and (ii) satisfy the requirements and conditions of Prohibited Transaction Class Exemption 95-60 issued by the Department of Labor; or

(f)(i) are made solely with assets managed by an in-house asset manager and (ii) satisfy the requirements and conditions of Prohibited Transaction Class Exemption 96-23 issued by the Department of Labor.

TRANSFER RESTRICTIONS

Each purchaser of Debentures, by its acceptance thereof, will be deemed to have acknowledged, represented to, warranted and agreed with the Company and the Initial Purchasers as follows:

(1) The Debentures are being offered for resale in a transaction not involving any public offering in the United States within the meaning of the Securities Act. The Debentures have not been registered under the Securities Act or any U.S. securities laws and they are being offered for resale in transactions not requiring registration under the Securities Act. The Debentures may not be reoffered, resold, pledged or otherwise transferred except (i) to a person whom the purchaser reasonably believes is a qualified institutional buyer in a transaction meeting the requirements of Rule 144A, (ii) pursuant to an exemption from registration under the Securities Act provided by Rule 144 thereunder (if available), (iii) to the Company or (iv) pursuant to an effective registration statement under the Securities Act, and, in each case, in accordance with all applicable U.S. state securities laws. The purchaser will, and will inform each subsequent holder that such subsequent holder is required to, notify any subsequent purchaser from it of the resale restrictions set forth in the preceding sentence. No representation is being made as to the availability of the exemption provided by Rule 144 for resales of the Debentures.

(2) It is not an "affiliate" (as defined in Rule 144 under the Securities Act) of the Company, it is not acting on behalf of the Company and it is a "Qualified Institutional Buyer" within the meaning of Rule 144A promulgated under the Securities Act and is aware that any sale of Debentures to it will be made in reliance on Rule 144A. Such acquisition will be for its own account or for the account of another Qualified Institutional Buyer.

(3) It is relying on the information contained in this Offering Memorandum in making its investment decision with respect to the Debentures. It acknowledges that no representation or warranty is made by the Initial Purchasers as to the accuracy or completeness of such materials. It further acknowledges that none of the Company or the Initial Purchasers or any person representing the Company or the Initial Purchasers has made any representation to it with respect to the Company or the offering or sale of any Debentures other than the information contained in this Offering Memorandum. It has had access to such financial and other information concerning the Company and the Debentures as it has deemed necessary in connection with its decision to purchase any of the Debentures, including an opportunity to ask questions of and request information from the Company and the Initial Purchasers.

(4) The purchaser understands that, unless registered under the Securities Act, the Debentures will bear a legend to the following effect unless otherwise agreed by the Company and the holder thereof.

"THIS DEBENTURE (OR ITS PREDECESSOR) HAS NOT BEEN REGISTERED UNDER THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT"), AND, ACCORDINGLY, MAY NOT BE OFFERED, SOLD, PLEDGED OR OTHERWISE TRANSFERRED, EXCEPT AS SET FORTH IN THE NEXT SENTENCE. BY ITS ACQUISITION HEREOF OR OF A BENEFICIAL INTEREST HEREIN, THE HOLDER:

(1) REPRESENTS THAT IT IS A "QUALIFIED INSTITUTIONAL BUYER" (AS DEFINED IN RULE 144A UNDER THE SECURITIES ACT) (A "QIB"); AND

(2) AGREES THAT IT WILL NOT RESELL OR OTHERWISE TRANSFER THIS DEBENTURE EXCEPT (A) TO THE COMPANY OR ANY OF ITS SUBSIDIARIES, (B) TO A PERSON WHOM THE SELLER REASONABLY BELIEVES IS A QIB PURCHASING FOR ITS OWN ACCOUNT OR FOR THE ACCOUNT OF A QIB IN A TRANSACTION MEETING THE REQUIREMENTS OF RULE 144A, (C) IN A TRANSACTION MEETING THE REQUIREMENTS OF RULE 144 UNDER THE SECURITIES ACT OR (D) PURSUANT TO AN EFFECTIVE REGISTRATION

DISCLOSURE ABOUT FORWARD-LOOKING STATEMENTS

This Offering Memorandum contains or incorporates by reference statements that do not directly or exclusively relate to historical facts. These types of statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. They represent our intentions, plans, expectations, assumptions and beliefs about future events. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ are often presented with forward-looking statements. In addition, other factors could cause actual results to differ materially from those indicated in any forward-looking statement. These include:

- Factors affecting operations, such as:
  - Unusual weather conditions;
  - Unscheduled generation outages;
  - Unusual maintenance or repairs;
  - Unanticipated changes in costs;
  - Environmental incidents; and
  - Electric transmission or gas pipeline system constraints.
- Legislative and regulatory initiatives and legal developments including costs of compliance with existing and future environmental requirements.
- Additional competition in electric or gas markets and continued industry consolidation.
- Financial or regulatory accounting principles.
- Political, legal and economic conditions and developments in the countries in which we have a presence.
- Changing market conditions and other factors related to physical energy and financial trading activities.
- The performance of projects undertaken and the success of efforts to invest in and develop new opportunities.
- Availability of, or cost of, capital.
- Employee workforce factors.
- Delays and other obstacles associated with mergers, acquisitions and investments in joint ventures.
- Costs and effects of legal and administrative proceedings, settlements, investigations and claims.
- The approval process for the pending merger of Duke Energy Corporation and ULH&P's ultimate parent company, Cinergy Corp., could delay the consummation of the pending merger or impose conditions that could materially impact the combined company and ULH&P.
- Business uncertainties, contractual restrictions, and the potential inability to attract and retain key personnel due to the pending merger.

These and other factors are discussed in our reports previously filed with the Commission. We are not required to revise or update forward-looking statements (whether as a result of changes in actual results, changes in assumptions or other factors affecting the statements). Our forward-looking statements reflect our best beliefs as of the time they are made and may not be updated for subsequent developments.

SUMMARY

This Offering Memorandum summarizes the terms of this offering of Debentures.

The Issuer

The following information is furnished solely to provide limited introductory information about ULH&P and does not purport to be comprehensive. Such information is qualified in their entirety by reference to detailed information and financial statements appearing in the documents incorporated herein by reference and, therefore, such information should be read together with this Offering Memorandum.

The Company, a Kentucky corporation, is an electric and gas utility. We are primarily engaged in the generation of electric energy and in the transmission, distribution, and sale of electric energy and the sale and transportation of natural gas in Northern Kentucky. The area we serve covers approximately 500 square miles, has an estimated population of 345,000 people, and includes the cities of Covington, Florence and Newport in Kentucky.

The Company is a wholly-owned subsidiary of The Cincinnati Gas & Electric Company ("CG&E"). CG&E is a wholly-owned subsidiary of Cinergy Corp.

Our principal executive offices are located at 139 East Fourth Street, Cincinnati, OH 45202. Our telephone number is (513) 421-9500.

Recent Developments

On January 25, 2006, ULH&P completed the acquisition of CG&E's approximately 69 percent ownership interest in the East Bend Station, located in Boone County, Kentucky, the Woodsdale Station, located in Butler County, Ohio, and one generating unit at the four-unit Miami Fort Station, located in Hamilton County, Ohio (totaling approximately 1,100 MWs of generating capacity), and associated transactions. The transaction was effective as of January 1, 2006, at a net book value of approximately $376 million for the generating assets, and approximately $24 million in inventory and other assets. The transaction closed following receipt of the last of the required regulatory approvals, that of the Commission under the Utility Holding Company Act of 1935 (repealed effective February 8, 2006), which approved the transaction in November 2005. The Kentucky Public Service Commission and the Federal Energy Regulatory Commission had earlier issued orders approving aspects of the transaction. At the closing, CG&E transferred its interests in the plants to ULH&P at net book value. The transaction will not affect current electric rates for ULH&P's customers. Updated rates are expected to be implemented January 1, 2007 pursuant to a rate case that incorporates the value of these assets into ULH&P's rate base.

In connection with the transfer of these assets, ULH&P accepted a capital contribution of approximately $140 million from CG&E and assumed certain liabilities of CG&E. In particular, ULH&P agreed to assume from CG&E all payment, performance, and other obligations of CG&E, with respect to (i) approximately $77 million of tax exempt pollution control debt currently shown on the balance sheet of CG&E and (ii) approximately $90 million of CG&E's outstanding accounts payable to affiliated companies, and (iii) certain asset retirement obligations of CG&E totaling approximately $2 million. Furthermore, approximately $91 million in deferred tax liabilities were assumed by ULH&P. ULH&P intends to repay the assumed tax exempt obligations with the proceeds from the issuance of tax exempt debt at ULH&P. The accounts payable obligations were paid with the proceeds from short term borrowings.

No action has been taken in any jurisdiction (including the United States) by the Company or the Initial Purchasers that would permit a public offering of the Debentures offered hereby in any jurisdiction where action for that purpose is required. The Debentures offered hereby may not be offered or sold, directly or indirectly, nor may this Offering Memorandum or any other offering material or advertisements in connection with the offer and sale of the Debentures be distributed or published in any jurisdiction, except under circumstances that will result in compliance with the applicable rules and regulations of such jurisdiction. Persons into whose possession this Offering Memorandum comes are advised to inform themselves about and to observe any restrictions relating to the Offering and the distribution of this Offering Memorandum. This Offering Memorandum does not constitute an offer to purchase or a solicitation of an offer to sell any of the Debentures offered hereby in any jurisdiction in which such an offer or a solicitation is unlawful.

Certain of the Initial Purchasers or their affiliates may engage from time to time in various general financing and banking transactions with the Company and its affiliates.

PLAN OF DISTRIBUTION

Subject to the terms and conditions set forth in the Purchase Agreement dated March 7, 2006, we have agreed to sell to each of the Initial Purchasers named below, and each of the Initial Purchasers has agreed to purchase from us, the respective amount of the Debentures set forth opposite its name below:

Underwriters	Principal Amount of Series A	Principal Amount of Series B
KeyBanc Capital Markets, a Division of McDonald Investments Inc.	$40,000,000	$52,000,000
LaSalle Financial Services, Inc.	$10,000,000	$13,000,000
Total	$50,000,000	$65,000,000

The Purchase Agreement provides that the obligation of the Initial Purchasers to purchase and accept delivery of the Debentures offered hereby is subject to the approval by their counsel of certain legal matters and to certain other conditions. The Initial Purchasers are obligated to purchase and accept delivery of all of the Debentures if any are purchased.

The Initial Purchasers propose to offer the Debentures for resale in transactions not requiring registration under the Securities Act or applicable state securities laws. Specifically, each Initial Purchaser will only offer or sell the Debentures to persons it reasonably believes to be "qualified institutional buyers" (as defined in Rule 144A under the Securities Act) in reliance on Rule 144A under the Securities Act. Each purchaser of the Debentures offered hereby will, by its purchase, be deemed to have made certain acknowledgements, representations, warranties and agreements as set forth under "Transfer Restrictions." The Initial Purchasers propose to offer the Debentures for resale initially at the offering price set forth on the cover of this Offering Memorandum. The offering price and other selling terms may be changed at any time without notice.

The Company has agreed to indemnify the Initial Purchasers against certain liabilities, including liabilities under the Securities Act, or to contribute to payments that the Initial Purchasers may be required to make in respect thereof.

In order to facilitate the offering of the Debentures, the Initial Purchasers may engage in transactions that stabilize, maintain or otherwise affect the price of the Debentures. Specifically, the Initial Purchasers may over-allot in connection with the offering, creating a short position in the Debentures, for their own accounts. In addition, to cover over-allotments or stabilize the price of the Debentures, the Initial Purchasers may bid for, and purchase, the Debentures in the open market. Finally, the Initial Purchasers may reclaim selling concessions allowed to dealers for distributing the Debentures in the offering, if the Initial Purchasers repurchase previously distributed Debentures in transactions to cover short positions, in stabilization transactions or otherwise. Any of these activities may stabilize or maintain the market price of the Debentures above independent market levels. The Initial Purchasers are not required to engage in these activities, and may end any of these activities at any time.

The Debentures have not been registered under the Securities Act and may not be offered or sold within the United States except in certain transactions exempt from or not subject to the registration requirements of the Securities Act. There is no public market for the Debentures and the Company does not intend to apply for listing of the Debentures on any national securities exchange or for the quotation of the Debentures on any automated dealer quotation system. There can be no assurance as to the liquidity of any market that may develop for the Debentures, the ability of the holders of the Debentures to sell their Debentures or the price at which holders would be able to sell their Debentures. The Company has been advised by the Initial Purchasers that the Initial Purchasers intend to make a market in the Debentures, subject to the limits imposed by the Securities Act and the Exchange Act; however, the Initial Purchasers are not obligated to do so, and may discontinue such market-making at any time without notice.

The following table summarizes this transaction for ULH&P:

	(in millions)
Assets Received	
Generating Assets	$376
Inventory	24
Total Assets Received	$400
Liabilities Assumed	
Debt	$ 77
Accounts payable to affiliated companies	90
Deferred tax liabilities	91
Other	2
Total Liabilities Assumed	$260
Contributed Capital from CG&E	$140

As part of this transaction, CG&E and ULH&P terminated the long-term wholesale power contract under which CG&E had previously supplied power to ULH&P. Further, CG&E also proposed to supply and ULH&P agreed to purchase back-up power from CG&E for planned and unplanned outages of the three generating plants through December 31, 2009 pursuant to a draft contract. The parties never executed this draft contract and ULH&P currently purchases back-up power, when needed, through the Midwest ISO energy markets. Given changes in circumstances, including the implementation of the Midwest ISO Energy Markets Tariff, CG&E and ULH&P are planning to propose an alternative arrangement for supplying back-up power to ULH&P. At this time, whether and the conditions under which the KPSC may allow ULH&P to recover any increased costs for an alternative arrangement for the supply of back-up power are unknown and CG&E and ULH&P cannot determine the magnitude of any potential increased costs for back-up power.

ULH&P retail generation rates, including fuel cost recovery, are frozen until January 1, 2007. During 2006, fluctuation in fuel costs will cause volatility in ULH&P's earnings.

With respect to the transfer of the generating assets described above, we have not included in this Offering Memorandum pro forma financial statements giving effect to such transfer for 2005. We do not yet have financial information for the generating assets prepared in accordance with GAAP. In additon, we have not yet prepared pro forma financial information giving effect to the transfer of the generating assets. The final financial information for the generating assets may be materially different from the information we now have available.

The Offering

Issuer	The Union Light, Heat and Power Company
Securities Offered	$115,000,000 aggregate principal amount of Debentures with $50,000,000 of 5.75% Debentures due 2016 Series A and $65,000,000 of 6.20% Debentures due 2036 (Series B) (collectively, the "Debentures")
Maturity Date	Series A will mature on March 10, 2016 and Series B will mature on March 10, 2036.
Interest Rate	5.75% on Series A and 6.20% on Series B
Interest Payment Dates	Each March 10 and September 10, commencing September 10, 2006
Record Dates	One business day before the relevant interest payment date
Optional Redemption	We will have the right to redeem the Debentures, in whole or from time to time in part, at our option on not less than 30 nor more than 60 days' notice, at a redemption price equal to the sum of (i) the principal amount of the Debentures being redeemed plus accrued and unpaid interest thereon to the redemption date, and (ii) a make-whole amount, if any, as more fully described in "Description of the Debentures—Optional Redemption by ULH&P" on pages 13 and 14 of this Offering Memorandum.
Ranking	The Debentures will be senior unsecured indebtedness of the Company and will rank equally with all of our other senior unsecured and unsubordinated indebtedness.
Listing	We will not list the Debentures on any securities exchange or include them in any automated quotation system.
Further Issues	We may from time to time, without notice to or the consent of the registered holders of the Debentures, create and issue additional debt securities having the same terms as, and ranking equally and ratably with, the Debentures in all respects. In addition, we may from time to time, without notice to or the consent of the registered holders of the Debentures, create and issue secured debt securities pursuant to a first mortgage trust indenture (yet to be concluded) which would have priority over unsecured debt with respect to the assets secured by the first mortgage trust indenture.
Use of Proceeds	We estimate that we will receive net proceeds from this offering, after deducting expenses and Initial Purchasers' discount, of approximately $113.7 million, which we intend to use to repay outstanding short-term indebtedness including short-term debt arising from the transfer of generating assets from CG&E to ULH&P as described under "Recent Developments" in the Summary section of this Offering Memorandum, for the redemption of long-term debentures in the amount of $15,000,000, and for other corporate purposes. The short-term debt consists of borrowings at variable interest rates.
Trustee	Deutsche Bank Trust Company Americas.

the principal of and any premium and interest on the Debentures of the series as they become due. We will also be required, among other things, to deliver to the trustee an opinion of counsel to the effect that holders of such Debentures will not recognize gain or loss for federal income tax purposes as a result of such deposit and defeasance of certain obligations and will be subject to federal income tax on the same amount, in the same manner and at the same times as would have been the case if such deposit and defeasance did not occur. If we were to exercise this option with respect to either series of the Debentures and the Debentures subsequently were declared due and payable because of the occurrence of any event of default, the amount of money and U.S. Government Obligations deposited in trust would be sufficient to pay amounts due on the Debentures of the series at the time of their respective stated maturities but might not be sufficient to pay the amounts due upon acceleration resulting from the event of default. In that case, we would remain liable for those payments.

Title

Union Light and the Trustee, and any agent of Union Light or the Trustee, may treat the person in whose name a Debenture is registered as the absolute owner thereof (whether or not the debt security may be overdue) for the purpose of making payment and for all other purposes.

Governing Law

The Indenture and the Debentures will be governed by, and construed in accordance with, the laws of the State of New York.

Concerning the Trustee

Deutsche Bank Trust Company Americas is the trustee under the Indenture. Deutsche Bank also acts as the trustee for certain debt securities of one of our affiliates. Deutsche Bank makes loans to, and performs other financial services for, us and our affiliates, in the normal course of business.

- impair the right to institute suit for the enforcement of any payment on or with respect to the Debenture;
- reduce the percentage in aggregate principal amount of outstanding Debentures of either series, the consent of whose holders is required for modification or amendment of the Indenture;
- reduce the percentage in aggregate principal amount of outstanding Debentures of either series necessary for waiver of compliance with certain provisions of the Indenture or for waiver of certain defaults; or
- modify the provisions relating to modification and waiver.

The holders of not less than a majority in aggregate principal amount of the outstanding Debentures of either series may waive, with respect to that series, our compliance with certain restrictive provisions of the Indenture. The holders of a majority in aggregate principal amount of the outstanding Debentures of either series may waive, with respect to that series, any past default under the Indenture, except a default in the payment of principal, premium, or interest and certain covenants and provisions of the Indenture which cannot be modified or amended without the consent of the holder of each outstanding Debenture of the series affected.

Generally, we will be entitled to set any day as a record date for the purpose of determining the holders of outstanding Debentures entitled to give or take any direction, notice, consent, waiver, or other action under the Indenture, in the manner and subject to the limitations provided in the Indenture. In certain limited circumstances, the trustee will be entitled to set a record date for action by holders. If a record date is set for any action to be taken by holders of a particular series, the action may be taken only by persons who are holders of outstanding Debentures of that series on the record date. To be effective, the action must be taken by holders of the requisite aggregate principal amount of the Debentures within 180 days following the record date, or such other shorter period as we (or the trustee, if it sets the record date) may specify.

Defeasance and Covenant Defeasance

The Debentures of each series will be subject to defeasance and covenant defeasance as provided in the Indenture.

We will be discharged from all our obligations with respect to those Debentures (except for certain obligations to exchange or register the transfer of Debentures, to replace stolen, lost or mutilated Debentures, to maintain paying agencies and to hold moneys for payment in trust) upon the deposit with the Trustee in trust for the benefit of the holders of such Debentures of money or U.S. Government Obligations, or both, which will provide money sufficient to pay the principal of and any Make-Whole Amount and interest on the Debentures as they become due. This defeasance or discharge may occur only if, among other things, we have delivered to the trustee an opinion of counsel to the effect that we have received from, or there has been published by, the United States Internal Revenue Service a ruling, or there has been a change in tax law, in either case to the effect that holders of the Debentures will not recognize gain or loss for federal income tax purposes as a result of the deposit, defeasance, and discharge and will be subject to federal income tax on the same amount, in the same manner and at the same times as would have been the case if the deposit, defeasance and discharge did not occur.

Defeasance of Certain Covenants.

We have the right to omit to comply with certain restrictive covenants that may be described under the Indenture, and the occurrence of certain events of default with respect to those restrictive covenants will no longer be applicable to a series of Debentures. In order to exercise this option, we will be required to deposit with the Trustee, in trust for the benefit of the holders of the Debentures of the series, money or U.S. Government Obligations, or both, which will provide money sufficient to pay

Events of Default	Each of the following will constitute an Event of Default under the Indenture with respect to the Debentures: (a) failure to pay principal of or any make-whole amount on any Debenture when due; (b) failure to pay any interest on any Debenture when due and continuance of such default for a period of 30 days; (c) failure to perform any other covenant of the Company in the Indenture, continued for 90 days after written notice has been given by the Trustee or the Holders of at least 35% in principal amount of the Debentures, as provided in the Indenture; and (d) certain events of bankruptcy, insolvency or reorganization. See "Description of the Debentures—Events of Default."
Transfer Restrictions	The Debentures will not be registered under the Securities Act and may not be offered or sold within the United States to or for the benefit of United States persons, except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act. See "Transfer Restrictions".

USE OF PROCEEDS

We estimate that we will receive net proceeds from this offering, after deducting expenses and Initial Purchasers' discount, of approximately $113.7 million, which we intend to use to repay outstanding short-term indebtedness including short-term debt arising from the transfer of generating assets from CG&E to ULH&P as described under "Recent Developments" in the Summary section of this Offering Memorandum, for the redemption of long-term debentures in the amount of $15,000,000, and for other corporate purposes. The short-term debt consists of borrowings at variable interest rates.

SELECTED FINANCIAL INFORMATION

The following table shows selected financial information of ULH&P, but it does not reflect the transfer of generating station assets by CG&E to ULH&P effective as of January 1, 2006, as described under "Summary—Recent Developments" above. This information is derived from our historical results. See "Incorporation of Certain Documents by Reference" on page 6 of this Offering Memorandum. All dollar amounts are in thousands.

Selected Income Information (in 000's)

	12 Months Ended December		
	2005	2004	2003
Operating Revenues	$388,127	$354,543	$332,153
Operating Income	$ 26,434	$ 33,380	$ 31,376
Interest Charges	$ 6,903	$ 5,179	$ 6,127
Net Income	$ 14,645	$ 18,638	$ 19,029
Ratio of Earnings to Fixed Charges	3.98	5.71	5.06

Capitalization

	Outstanding as of December 30, 2005	
	Amount (thousands)	% of Capitalization
Total Debt(1)	$136,513	41.0%
Common Stock Equity	196,459	59.0%
Total Capitalization	$332,972	100.0%

(1) Capital leases in the amount of $12,327 are included in the total debt numbers.

with respect to the outstanding Debentures of either series occurs, the principal amount of all the Debentures of that series will automatically, and without any action by the Trustee or any holder, become immediately due and payable. After any such acceleration, but before a judgment or decree based on acceleration, the holders of a majority in aggregate principal amount of the outstanding Debentures of that series may, under certain circumstances, rescind and annul the acceleration if all events of default, other than the non-payment of accelerated principal, have been cured or waived as provided in the Indenture. For information as to waiver of defaults, see "Modification and Waiver."

Subject to the provisions of the Indenture relating to the duties of the Trustee, if an event of default occurs, the Trustee will be under no obligation to exercise any of its rights or powers under the Indenture at the request or direction of any of the holders, unless the holders shall have offered to the Trustee reasonably satisfactory indemnity. Subject to these provisions for the indemnification of the Trustee, the holders of a majority in aggregate principal amount of the outstanding Debentures of either series will have the right to direct the time, method and place of conducting any proceeding for any remedy available to the trustee, or exercising any trust or power conferred on the trustee, with respect to the Debentures of that series.

No holder of a Debenture of either series will have any right to institute any proceeding with respect to the Indenture, or for the appointment of a receiver or a trustee, or for any other remedy thereunder, unless:

(a) the holder has previously given to the Trustee written notice of a continuing event of default with respect to the Debentures of that series;

(b) the holders of at least 35% in aggregate principal amount of the outstanding Debentures of that series have made written request, and have offered reasonably satisfactory indemnity, to the Trustee to institute a proceeding as trustee; and

(c) the Trustee has failed to institute a proceeding, and has not received from the holders of a majority in aggregate principal amount of the outstanding Debenture of that series a direction inconsistent with such request, within 60 days after receipt by the Trustee of the initial notice, written request and offer of indemnity. However, these limitations do not apply to a suit instituted by a holder of a Debenture for the enforcement of payment of the principal of or any Make-Whole Amount or interest on the Debenture on or after the applicable due date specified in the Debenture.

We will be required to furnish to the trustee annually a statement by certain of our officers as to whether or not we, to our knowledge, are in default in the performance or observance of any of the terms, provisions and conditions of the Indenture and, if so, specifying all known defaults.

Modification and Waiver

Modifications and amendments of the Indenture may be made by us and the trustee with the consent of the holders of not less than a majority in aggregate principal amount of the outstanding Debentures of each series affected by the modification or amendment; provided, however, no modification or amendment may, without the consent of the holder of each outstanding Debenture affected:

- change the stated maturity of the principal of, or any installment of principal of or interest on, the Debenture;
- reduce the principal amount of, or any Make-Whole Amount or interest on, the Debenture;
- reduce the amount of principal of payable upon acceleration of the maturity thereof;
- change the place or currency of payment of principal of, or any Make-Whole Amount or interest on, the Debenture;
- affect the applicability of the subordination provisions to the Debenture;

Exchange, Register and Transfer

The Debentures will be issuable only in fully registered form without coupons.

The Debentures may be presented for exchange or registration of transfer in the manner, at the places and subject to the restrictions set forth in the Debentures. Subject to the limitations noted in the Indenture, you will not have to pay for these services, except for any taxes or other governmental charges associated with these services.

Payment and Paying Agents

Payment of interest on a Debenture on any interest payment date will be made to the person in whose name the Debenture is registered at the close of business on the regular record date for the interest payment.

Principal of and any premium and interest on the Debentures will be payable at the office of the paying agent designated by us. However, we may elect to pay interest by check mailed to the address of the person entitled to the payment at the address appearing in the security register. The corporate trust office of the Trustee in the City of New York will be designated as our sole paying agent for payments with respect to Debentures of each series. We may at any time designate additional paying agents or rescind the designation of any paying agent or approve a change in the office through which any paying agent acts, except that we will be required to maintain a paying agent in each place of payment for the Debentures.

All moneys paid by us to a paying agent for the payment of the principal of or any Make-Whole Amount or interest on the Debentures which remain unclaimed at the end of 18 months after the principal, Make-Whole Amount or interest has become due and payable will be repaid to us, and the holder of the debt security thereafter may look only to us for payment.

Consolidation, Merger, and Sale of Assets

The Indenture does not contain any provision that restricts our ability to merge or consolidate with or into any other entity, sell or convey all or substantially all of our assets to any person or entity or otherwise engage in restructuring transactions, provided that the successor entity assumes due and punctual payment of the principal, Make-Whole Amount, if any, and interest on the Debentures.

Events of Default

Each of the following is defined as an event of default under the Indenture with respect to the Debentures of either series:

- failure to pay principal of or any Make-Whole Amount on any Debentures of that series when due;
- failure to pay any interest on any Debentures of that series when due, continued for 30 days;
- failure to perform any other of our covenants in the Indenture (other than a covenant included in the Indenture solely for the benefit of a series other than that series), continuing for 90 days after written notice has been given by the trustee, or the holders of at least 35% in aggregate principal amount of the outstanding Debentures of that series, as provided in the Indenture; and
- certain events of bankruptcy, insolvency or reorganization.

If an event of default (other than a bankruptcy, insolvency or reorganization event of default) with respect to the outstanding Debentures of either series occurs and is continuing, either the Trustee or the holders of at least 35% in aggregate principal amount of the outstanding Debentures of that series by notice as provided in the Indenture may declare the principal amount of the Debentures of that series to be due and payable immediately. If a bankruptcy, insolvency or reorganization event of default

DESCRIPTION OF THE DEBENTURES

The following is only a summary of certain provisions of the Indenture and, therefore, is not complete. You should read the Indenture in its entirety for provisions that may be important to you.

General

We are issuing $115,000,000 of Debentures, of which the Series A will mature on March 10, 2016 and the Series B will mature on March 10, 2036. The Debentures will be issued under the Indenture dated as of December 1, 2004, between ULH&P and Deutsche Bank Trust Company Americas, as Trustee, as amended and supplemented by the First Supplemental Indenture dated March 7, 2006 (the "Indenture"). The Debentures will be designated as specified on the cover of this Offering Memorandum.

The Debentures will be issued only in fully registered form in denominations of $1,000 and integral multiples of $1,000.

Interest

We will pay interest at an annual rate of 5.75% on Series A due 2016 and 6.20% on Series B due 2036 on March 10 and September 10 of each year commencing September 10, 2006. Interest will accrue from March 10, 2006.

The amount of interest payable for any period will be computed based on a 360-day year of twelve 30-day months. Interest will be paid to holders of record on the business day immediately preceding the interest payment date.

If any interest payment date is not a business day, then interest payable on that date will be paid on the next business day. No additional interest or other payment will be paid due to the delay.

Ranking

The Debentures will be unsecured and will rank equally with all of our unsecured and unsubordinated debt and other obligations from time to time outstanding.

Further Issues

We may from time to time, without notice to or the consent of the registered holders of the Debentures, create and issue additional debt securities having the same or similar terms as, and ranking equally and ratably with, the Debentures in all respects (or in all respects except for the payment of interest accruing prior to the issue date of such additional debt securities or except for the first payment of interest following the issue date of such additional debt securities). In addition, we may from time to time, without notice to or the consent of the registered holders of the Debentures, create and issue secured debt securities pursuant to a first mortgage trust indenture (yet to be concluded) which would have priority over unsecured debt with respect to the assets secured by the first mortgage trust indenture.

Optional Redemption by ULH&P

Subject to the terms of the Indenture, we will have the right to redeem each series of the Debentures, in whole or from time to time in part, until maturity (such redemption, a "Make-Whole Redemption," and the date thereof, the "Redemption Date"), at a redemption price equal to the sum of (i) the principal amount of the Debentures being redeemed plus accrued and unpaid interest thereon to the Redemption Date, and (ii) the Make-Whole Amount (as defined below), if any, with respect to the Debentures being redeemed.

"Make-Whole Amount" means the excess, if any, of (i) the sum, as determined by a Quotation Agent, of the present value of the principal amount of the Debentures to be redeemed, together with scheduled payments of interest thereon from the Redemption Date to the maturity date of the Debenture series to be redeemed (not including any portion of such payments of interest accrued as of the Redemption Date), in each case discounted to the Redemption Date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Adjusted Treasury Rate over (ii) 100% of the principal amount on the Redemption Date of the Debentures to be redeemed.

"Adjusted Treasury Rate" means, with respect to any Redemption Date for a Make-Whole Redemption, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, calculated using a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such Redemption Date, calculated on the third business day preceding the Redemption Date, plus 0.20% and 0.30% for Series A and Series B respectively (20 and 30 basis points).

"Comparable Treasury Issue" means the United States Treasury security selected by the Quotation Agent as having a maturity comparable to the remaining term from the Redemption Date to the Stated Maturity of the Debentures that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of the Debentures.

"Quotation Agent" means the Reference Treasury Dealer selected by the Company after consultation with the Trustee.

"Reference Treasury Dealer" means a primary U.S. Government securities dealer.

"Comparable Treasury Price" means, with respect to any Redemption Date for a Make-Whole Redemption, (i) the average of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) on the third business day preceding such Redemption Date, as set forth in the daily statistical release designated "H.15" (or any successor release) published by the Board of Governors of the Federal Reserve System or (ii) if such release (or any successor release) is not published or does not contain such prices on such business day, (A) the average of the Reference Treasury Dealer Quotations for such Redemption Date, after excluding the highest and lowest of such Reference Treasury Dealer Quotations, or (B) if the Trustee is provided fewer than three such Reference Treasury Dealer Quotations, the average of such Quotations.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any Redemption Date for a Make-Whole Redemption, the average of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Company and the Trustee by such Reference Treasury Dealer at 5:00 p.m., New York City time, on the third business day preceding such Redemption Date.

Notice of any redemption will be mailed by us at least 30 days but not more than 60 days before any Redemption Date to each holder of Debentures to be redeemed. If less than all the Debentures are to be redeemed at our option, the Depositary shall select the Debentures of such series to be redeemed in whole or in part in accordance with its standard procedures.

Unless we default in payment of the Redemption Price, on and after any Redemption Date, interest will cease to accrue on the Debentures or portions thereof called for redemption.

The Debentures will not be redeemable at the option of any holder prior to maturity and will not be subject to any sinking fund.

Global Securities

We will issue the Debentures in book-entry only form, which means that they will be represented by one permanent global certificate registered in the name of The Depository Trust Company, New York, New York (the "Depository" or "DTC"), or its nominee.

DTC will keep a computerized record of its participants (for example, your broker) whose clients purchased the Debentures. The participant will then keep a record of its clients who purchased the Debentures. The global certificate representing the Debentures may not be transferred, except that DTC, its nominees and their successors may transfer the entire global certificate to one another.

By using book-entry only form, we will not issue certificates to individual holders of the Debentures or register the ownership interests in the Debentures of individual holders. Beneficial interests in the global certificate will be shown on, and transfers of interests in the global certificate will be made only through, records maintained by DTC and its participants.

DTC has advised us that it is a limited-purpose trust company created to hold securities for its participating organizations ("Direct Participants") and to facilitate the clearance and settlement of transactions in those securities between Direct Participants through electronic book-entry changes in accounts of Direct Participants. Direct Participants include securities brokers and dealers (including the Initial Purchasers), banks, trust companies, clearing corporations and certain other organizations. Access to DTC's system is also available to other entities that clear through or maintain a direct or indirect, custodial relationship with a Direct Participant ("Indirect Participants" and, together with Direct Participants, "Participants"). DTC may hold securities beneficially owned by other persons only through its Participants and such other persons' ownership interests and transfer of ownership interests will be recorded only on the records of Participants, and not on the records maintained by DTC.

We will wire principal and interest payments to DTC's nominee. We and the Trustee will treat DTC's nominee as the owner of the global certificate for all purposes. Accordingly, we will have no direct responsibility or liability to pay amounts due on the Debentures to owners of beneficial interests in the global certificate.

It is DTC's current practice, upon receipt of any payment of principal and interest, to credit Direct Participants' accounts on the payment date according to their respective holdings of beneficial interests in the global certificate as shown on DTC's records. In addition, it is DTC's current practice to assign any consenting or voting rights to Direct Participants whose accounts are credited with Debentures on a record date by using an omnibus proxy. Payments by Participants to owners of beneficial interests in the global certificate, and voting by Participants, will be governed by the customary practices between the Participants and owners of beneficial interests, as is the case with securities held for the account of customers registered in "street name." However, these payments will be the responsibility of the Participants and not of DTC, the Trustee or ULH&P.

Withdrawal of Depository

If DTC notifies us that it is unwilling or unable to continue as depository or ceases to be eligible under applicable law, and a successor depository is not appointed within 90 days, Debentures in definitive form will be issued in exchange for the relevant global security. In addition, we may at any time and in our sole discretion determine not to have any of the Debentures of a series represented by one or more global securities and, in such event, Debentures of the series in definitive form will be issued in exchange for all of the global security or global securities representing the Debentures. Any Debentures issued in definitive form in exchange for a global security will be registered in the name or names that DTC gives to the Trustee. We expect that the instructions will be based upon directions received by DTC from participants with respect to ownership of beneficial interests in the global security.

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

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

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
Union Light, Heat and Power Company, The	End of 2005/Q4

Deloitte

Deloitte & Touche LLP
250 East Fifth Street
Suite 1900
P.O. Box 5340
Cincinnati, OH 45201-5340
USA

Tel: +1 513 784 7100
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

The Union Light, Heat and Power Company
Covington, Kentucky

We have audited the balance sheet – regulatory basis of The Union Light, Heat and Power Company as of December 31, 2005, and the related statements of income – regulatory basis; retained earnings – regulatory basis; cash flows – regulatory basis; and accumulated other comprehensive income, comprehensive income, and hedging activities – regulatory basis for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Note 1 (d), these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, such financial statements present fairly, in all material respects, the assets, liabilities and proprietary capital of The Union Light, Heat and Power Company as of December 31, 2005, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

This report is intended solely for the information and use of the board of directors and management of The Union Light, Heat and Power Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

February 17, 2006

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

IDENTIFICATION

01 Exact Legal Name of Respondent Union Light, Heat and Power Company, The	02 Year/Period of Report End of 2005/Q4
3 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)* 1697 A. Monmouth St., Newport, KY 41071	
05 Name of Contact Person David L. Wozny	06 Title of Contact Person VP Finance & Controller
07 Address of Contact Person *(Street, City, State, Zip Code)* 139 East Fourth Street, Cincinnati, Ohio 45202	

08 Telephone of Contact Person, *Including Area Code* (513) 287-2213	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Lynn J. Good 02 Title Executive Vice President and CFO	03 Signature Lynn J. Good Lynn J. Good	04 Date Signed *(Mo, Da, Yr)* 3/31/06

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
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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 tain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	N/A
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	N/A
17	Electric Plant Held for Future Use	214	N/A
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	N/A
21	Materials and Supplies	227	
22	Allowances	228-229	N/A
23	Extraordinary Property Losses	230	N/A
24	Unrecovered Plant and Regulatory Study Costs	230	N/A
25	Other Regulatory Assets	232	
26	Miscellaneous Deferred Debits	233	
27	Accumulated Deferred Income Taxes	234	
28	Capital Stock	250-251	
29	Other Paid-in Capital	253	
30	Capital Stock Expense	254	N/A
31	Long-Term Debit	256-257	
32	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
33	Taxes Accrued, Prepaid and Charged During the Year	262-263	
34	Accumulated Deferred Investment Tax Credits	266-267	
35	Other Deferred Credits	269	
36	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Other Property	274-275	
38	Accumulated Deferred Income Taxes-Other	276-277	
39	Other Regulatory Liabilities	278	
40	Electric Operating Revenues	300-301	
41	Sales of Electricity by Rate Schedules	304	
42	Sales for Resale	310-311	N/A
43	Electric Operation and Maintenance Expenses	320-323	
44	Purchased Power	326-327	
45	Transmission of Electricity for Others	328-330	
46	Transmission of Electricity by Others	332	
47	Miscellaneous General Expenses-Electric	335	
48	Depreciation and Amortization of Electric Plant	336-337	
49	Regulatory Commission Expenses	350-351	
50	Research, Development and Demonstration Activities	352-353	N/A
51	Distribution of Salaries and Wages	354-355	
52	Common Utility Plant and Expenses	356	
53	Purchase and Sale of Ancillary Services	398	
54	Monthly Transmission System Peak Load	400	
55	Electric Energy Account	401	
56	Monthly Peaks and Output	401	
57	Steam Electric Generating Plant Statistics	402-403	N/A
58	Hydroelectric Generating Plant Statistics	406-407	N/A
59	Pumped Storage Generating Plant Statistics	408-409	N/A
60	Generating Plant Statistics Pages	410-411	N/A
61	Transmission Line Statistics Pages	422-423	
62	Transmission Lines Added During the Year	424-425	
63	Substations	426-427	
64	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [ ] Four copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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.

DAVID L. WOZNY
VICE PRESIDENT FINANCE AND CONTROLLER
139 EAST FOURTH STREET
CINCINNATI, OHIO 45202

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

INCORPORATED UNDER THE LAWS OF THE COMMONWEALTH OF KENTUCKY ON MARCH 20, 1901

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.

KENTUCKY - GAS AND 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
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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.

CINERGY CORP. OWNS 100% OF THE OUTSTANDING COMMON STOCK OF THE CINCINNATI GAS & ELECTRIC COMPANY (THE RESPONDENT'S PARENT COMPANY). THE CINCINNATI GAS & ELECTRIC COMPANY OWNS 100% OF THE OUTSTANDING CAPITAL STOCK OF THE RESPONDENT.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	NA			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	CHAIRMAN OF THE BOARD AND CHEIF EXECUTIVE OFFICER	JAMES E. ROGERS	
2	EXECUTIVE VICE PRESIDENT	MICHAEL J. CYRUS	
3	EXECUTIVE VICE PRESIDENT	WILLIAM J. GREALIS	
4	EXECUTIVE VICE PRESIDENT	R. FOSTER DUNCAN	
5	EXECUTIVE VICE PRESIDENT AND CHIEF LEGAL OFFICER	MARC E. MANLY	
6	EXECUTIVE VICE PRESIDENT AND CHIEF ADMINISTRATIVE OFFICE	FREDERICK J. NEWTON III	
7	EXECUTIVE VICE PRESIDENT	JAMES L. TURNER	
8	SENIOR VICE PRESIDENT AND CHIEF RISK OFFICER	THEODORE R. MURPHY II	
9	PRESIDENT	GREGORY C. FICKE	
10	VICE PRESIDENT AND CONTROLLER	DAVID L. WOZNY	
11	SECRETARY AND CHIEF COMPLIANCE OFFICER	JULIA S. JANSON	
12	EXECUTIVE VICE PRESIDENT AND CHIEF FINANCIAL OFFICER	LYNN J. GOOD	
13			
14	SEE DISCLOSURE OF CHANGES ON PG 108-109.		
15			
16	NOTE:		
17	AMOUNT IN COLUMN (C) REPRESENTS TOTAL		
18	BASE SALARY, NOT RESPONDENT'S ALLOCATED		
19	SHARE.		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.

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	JAMES E. ROGERS (CHAIRMAN OF THE BOARD AND CEO)	139 EAST FOURTH STREET
2		CINCINNATI, OHIO 45202
3		
4	JAMES L. TURNER (EXECUTIVE VICE PRESIDENT)	139 EAST FOURTH STREET
5		CINCINNATI, OHIO 45202
6		
7	MICHAEL J. CYRUS (EXECUTIVE VICE PRESIDENT)	139 EAST FOURTH STREET
8		CINCINNATI, OHIO 45202
9		
10	GREGORY C. FICKE (PRESIDENT)	139 EAST FOURTH STREET
11		CINCINNATI, OHIO 45202
12		
13	NOTE: THERE IS NO EXECUTIVE COMMITTEE	
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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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 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

1. None

2. See Note 2 of the "Notes to the Financial Statements"

3. See Note 12 of the "Notes to the Financial Statements"

4. None

5. Installation of .04miles of 69kv transmission line located in Kentucky, completed 06/01/05. No additional customers added to revenue.

6. No obligation have been incurred or assumed by respondent as guarantor. For details on respondent issuances and redemption of long term debt and other short term debt, see Notes to the Financial Statements - - Section 4, Long-Term Debt and Section 5, Notes Payable.

7. None

8. Employees bargained for by the United Steelworkers Local 12049 received a 3 percent wage increase effective May 16, 2005. Employees bargained for by the International Brotherhood of Electrical Workers Local 1347 received a 3 percent wage increase effective April 1, 2005. The manual and technical employees and the full-time clerical employees bargained for by the Utility Workers Union of America Local 600 received a 3 percent and 2.5 percent increase, respectively, effective April 4, 2005. Changes due to the above and wage scale adjustments during the year resulted in an estimated annual wage increase of $413,300. Changes in supervisory, administrative, and professional employees resulted in an estimated annual wage increase of $40,300

9. None

10. None

11. Reserved

12. N/A

13.

Board of Director Change:

Effective June 1, 2005:

Gregory C. Ficke replaces Michael J. Cyrus as a member of the Board of Directors

Officer Changes:

Effective February 2, 2005:

Wendy L. Aumiller is appointed Vice President and Treasurer.
Lynn J. Good is appointed Vice President-Finance and Controller.
Bradley C. Arnett is appointed Assistant Treasurer.

Effective February 28, 2005:

Bernard F. Roberts, Vice President, **retired**.

Effective May 4, 2005:

Brian P. Davey appointment as Assistant Controller ends.

Effective June 1, 2005:

R. Foster Duncan, Executive Vice President, resigned
William J. Grealis, Executive Vice President, retired

Effective August 24, 2005:

Lynn J. Good was appointed as Executive Vice President and Chief Financial Officer. Ms. Good succeeds **James L. Turner** as CFO. Upon Ms. Good's appointment, Mr. Turner's sole position is Executive Vice President.

David L. Wozny was appointed as Vice President and Controller. Mr. Wozny succeeds Lynn J. Good in both roles.

14. None

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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	602,623,797	566,078,910
3	Construction Work in Progress (107)	200-201	12,840,088	6,070,516
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		615,463,885	572,149,426
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	214,273,344	201,255,639
6	Net Utility Plant (Enter Total of line 4 less 5)		401,190,541	370,893,787
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)		401,190,541	370,893,787
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		18,614,669	18,591,765
19	(Less) Accum. Prov. for Depr. and Amort. (122)		6,363,598	5,003,725
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)		2,500	3,068
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		12,253,571	13,591,108
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		9,873,128	4,195,084
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		2,500	2,500
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		1,654,134	1,260,726
41	Other Accounts Receivable (143)		125,468	202,158
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		161,732	12,593
43	Notes Receivable from Associated Companies (145)		29,266,666	20,674,884
44	Accounts Receivable from Assoc. Companies (146)		6,567,196	5,671,436
45	Fuel Stock (151)	227	1,841,070	1,991,462
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	396,154	384,240
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

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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	20,743	21,322
55	Gas Stored Underground - Current (164.1)		8,509,260	6,102,597
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		4,499,648	284,770
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		601	601
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		62,594,836	40,779,187
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		972,907	1,039,587
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	40,155,992	41,562,613
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)		47,450	50,958
77	Temporary Facilities (185)		-128,109	-102,678
78	Miscellaneous Deferred Debits (186)	233	1,731,550	1,809,937
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		2,137,887	2,319,315
82	Accumulated Deferred Income Taxes (190)	234	6,243,543	7,005,341
83	Unrecovered Purchased Gas Costs (191)		1,282,227	-318,744
84	Total Deferred Debits (lines 69 through 83)		52,443,447	53,366,329
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		528,482,395	478,630,411

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Rresubmission	/ /	end of 2005/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	8,779,995	8,779,995
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	18,838,946	18,838,946
7	Other Paid-In Capital (208-211)	253	4,920,874	4,616,415
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)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	166,241,890	161,562,305
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)	-2,322,809	-1,285,814
16	Total Proprietary Capital (lines 2 through 15)		196,458,896	192,511,847
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
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	95,000,000	95,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		590,531	660,326
24	Total Long-Term Debt (lines 18 through 23)		94,409,469	94,339,674
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		11,093,557	8,334,846
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		450,998	668,673
29	Accumulated Provision for Pensions and Benefits (228.3)		7,062,514	6,451,794
30	Accumulated Miscellaneous Operating Provisions (228.4)		2,019,334	2,019,555
31	Accumulated Provision for Rate Refunds (229)		1,245,000	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		6,305,777	0
35	Total Other Noncurrent Liabilities (lines 26 through 34)		28,177,180	17,474,868
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		26,206,228	16,027,742
39	Notes Payable to Associated Companies (233)		29,777,470	11,245,745
40	Accounts Payable to Associated Companies (234)		26,815,087	22,236,349
41	Customer Deposits (235)		4,003,247	3,622,812
42	Taxes Accrued (236)	262-263	6,768,547	-570,525
43	Interest Accrued (237)		1,374,046	1,369,973
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Rresubmission	/ /	end of 2005/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)		2,153,116	1,540,658
48	Miscellaneous Current and Accrued Liabilities (242)		1,563,172	1,614,094
49	Obligations Under Capital Leases-Current (243)		1,233,028	802,146
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		99,893,941	57,888,994
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		2,373,528	2,721,042
57	Accumulated Deferred Investment Tax Credits (255)	266-267	2,372,760	2,625,788
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	12,365,923	11,829,298
60	Other Regulatory Liabilities (254)	278	33,386,966	33,811,402
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)		57,739,975	63,913,454
64	Accum. Deferred Income Taxes-Other (283)		1,303,757	1,514,044
65	Total Deferred Credits (lines 56 through 64)		109,542,909	116,415,028
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		528,482,395	478,630,411

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STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
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 (k) the quarter to date amounts for other utility function for the prior year quarter.
4. 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.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

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	386,466,564	351,299,131		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	328,640,926	289,616,466		
5	Maintenance Expenses (402)	320-323	5,895,908	7,196,077		
6	Depreciation Expense (403)	336-337	17,038,206	16,531,713		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	2,226,788	2,143,542		
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	4,689,534	3,136,049		
15	Income Taxes - Federal (409.1)	262-263	3,106,170	2,673,009		
16	- Other (409.1)	262-263	532,325	-394,037		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	8,225,074	8,064,784		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	6,256,096	1,240,832		
19	Investment Tax Credit Adj. - Net (411.4)	266	-253,028	-252,963		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		363,845,807	327,473,808		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		22,620,757	23,825,323		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
238,305,657	227,211,811	148,160,907	124,087,320			2
						3
209,418,915	195,595,660	119,222,011	94,020,806			4
3,978,328	5,464,493	1,917,580	1,731,584			5
9,336,586	8,928,792	7,701,620	7,602,921			6
						7
1,208,309	1,328,646	1,018,479	814,896			8
						9
						10
						11
						12
						13
2,373,876	1,730,333	2,315,658	1,405,716			14
185,074	-2,287,322	2,921,096	4,960,331			15
-136,933	-650,973	669,258	256,936			16
2,631,594	4,531,871	5,593,480	3,532,913			17
4,856,120	877,896	1,399,976	362,936			18
-176,447	-178,744	-76,581	-74,219			19
						20
						21
						22
						23
						24
223,963,182	213,584,860	139,882,625	113,888,948			25
14,342,475	13,626,951	8,278,282	10,198,372			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		22,620,757	23,825,323		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		869,203	794,052		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		364,178	242,741		
33	Revenues From Nonutility Operations (417)		4,586	2,418		
34	(Less) Expenses of Nonutility Operations (417.1)			460,532		
35	Nonoperating Rental Income (418)		-573,798	1,090,751		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		2,525,516	1,593,291		
38	Allowance for Other Funds Used During Construction (419.1)		642,187	-18,186		
39	Miscellaneous Nonoperating Income (421)		11,826	3,467		
40	Gain on Disposition of Property (421.1)		9,269	116,918		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		3,124,611	2,879,438		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		60,081	168,597		
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	17,146	28,064		
46	Life Insurance (426.2)					
47	Penalties (426.3)		791			
48	Exp. for Certain Civic, Political & Related Activities (426.4)		145,117	177,235		
49	Other Deductions (426.5)		1,230,379	579,479		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,453,514	953,375		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	265,069	407,479		
53	Income Taxes-Federal (409.2)	262-263	1,884,356	385,043		
54	Income Taxes-Other (409.2)	262-263	148,663	111,163		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	445,290	1,009,902		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277		-20,291		
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)		2,743,378	1,933,878		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-1,072,281	-7,815		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		6,052,870	4,154,537		
63	Amort. of Debt Disc. and Expense (428)		136,476	61,944		
64	Amortization of Loss on Reaquired Debt (428.1)		181,428	181,428		
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)	340	69,069	267,806		
68	Other Interest Expense (431)	340	686,962	560,287		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		223,434	46,712		
70	Net Interest Charges (Total of lines 62 thru 69)		6,903,371	5,179,290		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		14,645,105	18,638,218		
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)		14,645,105	18,638,218		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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		161,562,305	157,524,087
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		14,645,105	18,638,218
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				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Payable to the Cincinnati Gas & Electric Company		-9,965,520	(14,600,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-9,965,520	(14,600,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		166,241,890	161,562,305
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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 distributed 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)
39				
40				
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)		166,241,890	161,562,305
	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
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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)	14,645,105	18,638,218
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	17,038,206	16,531,713
5	Amortization of:		
6	Plant Items	2,226,788	2,143,542
7	Debt Discount, Premium, Exp, Loss on Reaquired Debt	317,904	243,372
8	Deferred Income Taxes (Net)	2,414,268	7,854,145
9	Investment Tax Credit Adjustment (Net)	-253,028	-252,963
10	Net (Increase) Decrease in Receivables	-9,655,121	-3,025,975
11	Net (Increase) Decrease in Inventory	-2,267,606	-563,232
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	23,473,222	3,738,402
14	Net (Increase) Decrease in Other Regulatory Assets	439,800	-2,005,364
15	Net Increase (Decrease) in Other Regulatory Liabilities		
16	(Less) Allowance for Other Funds Used During Construction	642,187	-18,186
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-3,481,786	2,063,150
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	44,255,565	45,383,194
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-44,124,811	-32,327,983
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant	-3,661,670	-1,511,326
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-642,187	18,186
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-47,144,294	-33,857,495
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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 estments, fixed assets, intangibles, etc.
Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	568	-12
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-47,143,726	-33,857,507
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		39,360,800
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	18,531,725	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	18,531,725	39,360,800
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		-33,987,651
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-9,965,520	-14,600,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	8,566,205	-9,226,851
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	5,678,044	2,298,836
87			
88	Cash and Cash Equivalents at Beginning of Period	4,197,584	1,898,748
89			
90	Cash and Cash Equivalents at End of period	9,875,628	4,197,584

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) X An Original (2) _ A Resubmission	/ /	2005/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 18 Column: b

Other Items:

Unrecovered Purchased Gas Costs	(1,600,971)
Prepayments	(4,214,878)
Clearing Accounts	3,508
Miscellaneous Deferred Debits	78,387
Obligations under Capital Lease Non-Current	2,758,711
Accumulated Provisions	1,637,824
Customer Advances for Construction	(347,514)
Other Deferred Credits	536,625
Temporary Facilities	25,431
Net Utility Plant and Nonutility Property	1,858,697
Cost of Removal	(1,187,895)
Paid-in-Capital	304,459
Deferred Income Taxes	(2,297,175)
Accumulated Other Comprehensive Income	(1,036,995)
	(3,481,786)

Schedule Page: 120 Line No.: 18 Column:

Other Items:

Unrecovered Purchased Gas Costs	3,244,383
Prepayments	(5,864)
Clearing Accounts	27,571
Miscellaneous Deferred Debits	(1,457,212)
Obligations under Capital Lease Non-Current	1,215,234
Accumulated Provisions	(228,516)
Customer Advances for Construction	(359,036)
Other Deferred Credits	715,410
Temporary Facilities	(11,343)
Net Utility Plant	127,642
Net Nonutility Property	1,358,799
Cost of Removal	(1,588,088)
Long Term Debt	(150,000)
Paid-in-Capital	(85,867)
Deferred Income Taxes	56,690
Accumulated Other Comprehensive Income	(796,653)
	2,063,150

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

Voluntary Employees' Beneficiary Association (VEBA) Investment Trust 568

Schedule Page: 120 Line No.: 53 Column:

Voluntary Employees' Beneficiary Association (VEBA) Investment Trust (12)

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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

NOTES TO FINANCIAL STATEMENTS

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

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

NOTES TO FINANCIAL STATEMENTS

In this report Cinergy which includes Cinergy Corp. and all of our regulated and non-regulated subsidiaries.

1. Organization and Summary of Significant Accounting Policies

(a) Pending Merger

On May 8, 2005, Cinergy Corp. entered into an agreement and plan of merger with Duke Energy Corporation (Duke), a North Carolina corporation, whereby Cinergy Corp. will be merged with Duke. Under the merger agreement, each share of Cinergy Corp. common stock will be converted into 1.56 shares of common stock of the newly formed company, Duke Energy Holding Corp. (Duke Energy Holding).

The merger agreement has been approved by both companies' Boards of Directors. Consummation of the merger is subject to customary conditions, including, among others, the approval of the shareholders of both companies and the approvals of various regulatory authorities. See Note 2 for further information regarding the pending merger.

(b) Nature of Operations

Cinergy Corp., a Delaware corporation organized in 1993, owns all outstanding common stock of The Cincinnati Gas & Electric Company (CG&E) and PSI Energy, Inc. (PSI), both of which are public utilities, as well as Cinergy Investments, Inc. (Investments), its non-regulated investment holding company. The Union Light, Heat and Power Company (**ULH&P**), a Kentucky corporation organized in 1901, is a wholly-owned subsidiary of CG&E. **ULH&P** (1) transmits and distributes electricity, and (2) sells and transports natural gas, primarily within the northern Kentucky area. See Note 12 for further discussion of the transfer of certain generating assets from CG&E to **ULH&P** in January 2006.

(c) Repeal of the Public Utility Holding Company Act of 1935 (PUHCA 1935) and Establishment of the Federal Energy Regulatory Commission (FERC) Public Utility Holding Company Act of 2005 (PUHCA 2005)

Because Cinergy is a utility holding company, we are registered with the Securities and Exchange Commission (SEC) and were subject to regulation under the PUHCA 1935. The Energy Policy Act of 2005, among other provisions, repealed the PUHCA 1935 and replaced it with the PUHCA 2005, under the jurisdiction of the FERC, effective February 8, 2006. The net effect of these legislative changes was to abolish the regulatory regime imposed under the PUHCA 1935, while at the same time, enhancing the FERC's authority over books and records of holding companies, in order to assist the FERC and state utility regulators in protecting customers of regulated utilities. In December 2005, the FERC adopted final rules further implementing the provisions of the PUHCA 2005. Among other things, these rules impose certain limited filing and reporting obligations on holding companies such as Cinergy. At this time, it is too early to predict the overall impact that the Energy Policy Act of 2005 will have on our financial position or results of operations.

(d) Presentation

The accompanying financial statements are prepared on the regulatory basis of accounting in accordance with the requirements of the FERC, which is a comprehensive basis of accounting other than generally accepted accounting principles (GAAP). This basis of accounting differs from GAAP in that a complete statement of changes in proprietary capital has not been presented and the classification of certain balance sheet and income statement accounts does not conform with GAAP. This basis of accounting reflects the accounting and the ratemaking treatment authorized by the FERC and the Kentucky Public Service Commission (KPSC) in **ULH&P's** historical rate proceedings.

Management makes estimates and assumptions when preparing financial statements. Actual results could differ, as these estimates and assumptions involve judgment about future events or performance. These estimates and assumptions affect various matters, including:

- the reported amounts of assets and liabilities in **ULH&P's** Comparative Balance Sheets at the dates of the financial statements;

- the disclosure of contingent assets and liabilities at the dates of the financial statements; and
- the reported amounts of revenues and expenses in **ULH&P's** Statements of Income during the reporting periods.

(e) Regulation

ULH&P must comply with the rules prescribed by the SEC under the PUHCA 1935, through February 8, 2006. The PUHCA 1935 was replaced with the PUHCA 2005, under the FERC's jurisdiction, as previously discussed in (c). **ULH&P** must also comply with the other rules prescribed by the FERC and the KPSC.

ULH&P uses the same accounting policies and practices for financial reporting purposes as non-regulated companies under GAAP. However, sometimes actions by the FERC and the KPSC result in accounting treatment different from that used by non-regulated companies. When this occurs, **ULH&P** applies the provisions of Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (Statement 71). In accordance with Statement 71, **ULH&P** records regulatory assets and liabilities (expenses deferred for future recovery from customers or amounts provided in current rates to cover costs to be incurred in the future, respectively) on its Comparative Balance Sheets.

As of December 31, 2005, **ULH&P** continues to meet the criteria to apply Statement 71. If Kentucky was to implement deregulation legislation, the application of Statement 71 would need to be reviewed. Based on **ULH&P's** current regulatory orders and the regulatory environment in which they currently operate, the recovery of regulatory assets recognized in the accompanying Comparative Balance Sheets, as of December 31, 2005, is probable.

ULH&P's regulatory assets, liabilities, and amounts authorized for recovery through regulatory orders at December 31, 2005 and 2004, were as follows:

	2005	2004
	(in thousands)	
Regulatory assets		
Amounts due from customers - income taxes	$ 31,500	$ 37,664
Other	8,656	3,899
Total Regulatory assets	$ 40,156	$ 41,563
Regulatory liabilities		
Amounts due from customers - income taxes	$ 33,387	$ 33,811
Total Regulatory liabilities	$ 33,387	$ 33,811
Total	$ 6,769	$ 7,752
Unamortized cost of reacquiring debt	2,138	2,319
Total net regulatory assets	$ 8,907	$ 10,071
Authorized for recovery[1]	$ 7,168	$ 8,508

(1) At December 31, 2005, these amounts were being recovered through rates charged to customers over remaining periods ranging from 1 to 15 years for **ULH&P**

(f) Revenue Recognition

ULH&P records *Operating Revenues* (Account 400) for electric and gas service when delivered to customers. Customers are billed throughout the month as both gas and electric meters are read. **ULH&P** recognizes revenues for retail energy sales that have not yet been billed, but where gas or electricity has been consumed. This is termed "unbilled revenues" and is a widely recognized and accepted practice for utilities. In making our estimates of unbilled revenues, we use systems that consider various factors, including weather, in our calculation of retail customer consumption at the end of each month. Given the use of these systems and the fact that customers are billed monthly, **ULH&P** believes it is unlikely that materially different results will occur in future periods when these amounts are subsequently billed. Unbilled revenues for **ULH&P** as of December 31, 2005 and 2004 were $27 million and $23 million, respectively.

(g) Energy Purchases and Fuel Costs

The expenses associated with electric and gas services include electricity purchased from parent company (CG&E), natural gas purchased from others, and the associated transportation costs. These expenses are shown in **ULH&P's** Statements of Income as *Operation Expense* (Account 401).

(h) Cash and Cash Equivalents

ULH&P defines cash and cash equivalents as investments with maturities of three months or less when acquired, which includes *Cash* (Account 131) and *Working Fund* (Account 135).

During 2005 and 2004, **ULH&P** made cash interest payments of $6.6 million and $4.8 million (net of amounts capitalized), respectively. **ULH&P** had a cash income tax receipt of $2.7 million in 2005 and mad a cash income tax payment of $2.8 million in 2004.

(i) Inventory

ULH&P's inventories are accounted for at the lower of cost or market, with cost being determined using the weighted-average method.

Materials and supplies inventory is accounted for on a weighted-average cost basis.

(j) Utility Plant

Utility Plant (Accounts 101-106 and 114) includes the utility and equipment that is in use, being held for future use, or under construction. **ULH&P** reports our *Utility Plant* at its original cost, which includes:

- materials;
- contractor fees;
- salaries;
- payroll taxes;
- fringe benefits;
- allowance for funds used during construction (AFUDC) (described in (*ii*)); and
- other miscellaneous amounts.

ULH&P capitalizes costs for utility plant that are associated with the replacement or the addition of equipment that is considered a property unit. Property units are intended to describe an item or group of items. The cost of normal repairs and maintenance is expensed as incurred. When utility plant is retired, **ULH&P** charges the original cost, plus cost of removal, less salvage, to *Accumulated provision for depreciation* (Account 108), which is consistent with the composite method of depreciation. A gain or loss is recorded on the sale of utility plant if an entire operating unit, as defined by the FERC, is sold.

(i) Depreciation

ULH&P determines the provisions for depreciation expense using the straight-line method. The depreciation rates are based on periodic studies of the estimated useful lives and the net cost to remove the properties. **ULH&P** uses composite depreciation rates. These rates are approved by the KPSC. The average depreciation rates for *Utility Plant*, excluding software, was 3.4 percent and 3.5 percent for 2005 and 2004, respectively.

(ii) AFUDC

ULH&P finances construction projects with borrowed funds and equity funds. The KPSC allows **ULH&P** to record the costs of these funds as part of the cost of construction projects. AFUDC is calculated using a methodology authorized by the KPSC. These costs are credited on the Statements of Income to *Other Income* (Account 419.1) and *Other Interest Expense* (Account 431) for the equity and borrowed funds, respectively. The equity component of AFUDC was $0.6 million for 2005. The borrowed funds component of AFUDC, which is recorded on a pre-tax basis, was $0.2 million and $0.1 million for 2005 and 2004, respectively.

(k) Impairments of Long-Lived Assets

In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, **ULH&P** evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. So long as an asset or group of assets is not held for sale, the determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows (including related tax effects) attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a provision for an impairment loss if the carrying value is greater than the fair value. Once assets are classified as held for sale, the comparison of undiscounted cash flows to carrying value is disregarded and an impairment loss is recognized for any amount by which the carrying value exceeds the fair value of the assets less cost to sell.

(l) Asset Retirement Obligations

In accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations* (Statement 143), **ULH&P** recognizes the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred and can be reasonably estimated. The initial recognition of this liability is accompanied by a corresponding increase in *Utility Plant*. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to *Utility plant*), and for accretion of the liability due to the passage of time (recognized as *Operation Expenses*). Additional depreciation expense is recorded prospectively for any utility plant increases.

See (p) for a discussion of our December 31, 2005 adoption of FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (Interpretation 47), an interpretation of Statement 143.

ULH&P ratably accrues the estimated retirement and removal cost of rate regulated property, plant, and equipment when removal of the asset is considered likely, in accordance with established regulatory practices. The accrued, but not incurred, balance for these costs is classified as *Regulatory liabilities*, under Statement 71. For **ULH&P's** rate-regulated assets where our tariff rate includes a cost of removal component, we recognize liability for estimated costs of removal under Statement 71.

Approximately $2 million of asset retirement obligations were transferred to **ULH&P** from **CG&E** in January 2006 in conjunction with the transfer of generating assets. See Note 12 for additional information.

(m) Income Taxes

Cinergy and its subsidiaries, including **ULH&P**, file a consolidated federal income tax return and combined/consolidated state and local tax returns in certain jurisdictions. Cinergy and its subsidiaries, including **ULH&P**, have an income tax allocation agreement; the corporate taxable income method is used to allocate tax benefits to the subsidiaries whose investments or results of operations provide those tax benefits. Any tax liability not directly attributable to a specific subsidiary is allocated proportionately among the subsidiaries, including **ULH&P**, as required by the agreement.

SFAS No. 109, *Accounting for Income Taxes*, requires an asset and liability approach for financial accounting and reporting of income taxes. The tax effects of differences between the financial reporting and tax basis of accounting are reported as *Accumulated Deferred Income Taxes* assets (Account 190) or liability (Accounts 281, 282 and 283) in **ULH&P's** Comparative Balance Sheets and are based on currently enacted income tax rates. We evaluate quarterly the realizability of our deferred tax assets by assessing our valuation allowance and adjusting the amount of such allowance, if necessary.

Investment tax credits, which have been used to reduce **ULH&P's** federal income taxes payable, have been deferred for financial reporting purposes. These deferred investment tax credits are being amortized over the useful lives of the property to which they are related. For a further discussion of income taxes, see Note 10.

(n) Contingencies

In the normal course of business, **ULH&P** is subject to various regulatory actions, proceedings, and lawsuits related to environmental, tax, or other legal matters. We reserve for these potential contingencies when they are deemed probable and reasonably estimable liabilities. However, these amounts are estimates based upon assumptions involving judgment and therefore actual results could differ. For further discussion of contingencies, see Note 11.

(o) Pension and Other Postretirement Benefits

Cinergy, including **ULH&P**, provides benefits to retirees in the form of pension and other postretirement benefits. Our reported costs of providing these pension and other postretirement benefits are developed by actuarial valuations and are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Changes made to the provisions of the plans may impact current and future pension costs. Pension costs associated with Cinergy's defined benefit plans are impacted by employee demographics, the level of contributions we make to the plan, and earnings on plan assets. These pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation. Changes in pension obligations associated with the previously discussed factors are not immediately recognized as pension costs on the Statements of Income but are deferred and amortized in the future over the average remaining service period of active plan participants to the extent they exceed certain thresholds prescribed by SFAS No. 87, *Employers' Accounting for Pensions* (Statement 87).

Other postretirement benefit costs are impacted by employee demographics, per capita claims costs, and health care cost trend rates and may also be affected by changes in key actuarial assumptions, including the discount rate used in determining the accumulated postretirement benefit obligation (APBO). Changes in postretirement benefit obligations associated with these factors are not immediately recognized as postretirement benefit costs but are deferred and amortized in the future over the average remaining service period of active plan participants to the extent they exceed certain thresholds prescribed by SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* (Statement 106).

Cinergy reviews and updates its actuarial assumptions for its pension and postretirement benefit plans on an annual basis, unless plan amendments or other significant events require earlier remeasurement at an interim period. For additional information on pension and other postretirement benefits, see Note 9.

(p) Accounting Changes – Asset Retirement Obligations

In March 2005, the FASB issued Interpretation No. 47, an interpretation of Statement 143. Statement 143 requires recognition of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred. Interpretation 47 clarifies that a conditional asset retirement obligation (which occurs when the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity) is a legal obligation within the scope of Statement 143. As such, the fair value of a conditional asset retirement obligation must be recognized as a liability when incurred if the liability's fair value can be reasonably estimated. Interpretation 47 also clarifies when sufficient information exists to reasonably estimate the fair value of an asset retirement obligation.

ULH&P adopted Interpretation 47 on December 31, 2005 and recorded multiple asset retirement obligations as a result. These asset retirement obligations primarily related to obligations associated with retiring gas mains, recorded by **ULH&P**.

The effect of adoption for **ULH&P** included balance sheet reclassifications of approximately $5 million from *Regulatory liabilities*. See discussion of *Regulatory liabilities* previously disclosed in (e). The increase in asset retirement obligations from adopting Interpretation 47 was $6 million for **ULH&P**.

Pro-forma results as if Interpretation 47 was applied retroactively for the years ended December 31, 2005 and 2004, are not materially different from reported results. The December 31, 2004 pro-forma liabilities for asset retirement obligations recorded as a result of the adoption of Interpretation 47 are not materially different than the December 31, 2005 balances.

(q) Related Party Transactions

Services provides **ULH&P** with a variety of centralized administrative, management, and support services in accordance with agreements approved by the SEC under the PUHCA 1935. The costs of these services are charged to our companies on a direct basis, or for general costs which cannot be directly attributed, based on predetermined allocation factors, including the following ratios:

- sales;
- number of employees;
- number of customers; and
- construction expenditures.

These costs were $31 million and $21 million for the years ended December 31, 2005 and 2004, respectively:

Through December 31, 2005 **ULH&P** purchased energy from CG&E pursuant to a contract effective January 1, 2002, which was approved by the FERC and KPSC. This five-year agreement is a negotiated fixed-rate contract with CG&E. **ULH&P** purchased energy from CG&E for resale in the amounts of $168 million and $162 million, for the years ended December 31, 2005 and 2004, respectively. These amounts are reflected in the Statements of Income for **ULH&P** as *Operation Expenses*. This contract was terminated effective December 31, 2005, in connection with the transfer of generating assets from CG&E to **ULH&P**. For information on the transfer of generating assets to **ULH&P** on January 1, 2006, see Note 12.

CG&E and **ULH&P** enter into various agreements with Cinergy Marketing & Trading, LP (Marketing & Trading) to manage their interstate pipeline transportation, storage capacity, and gas supply contracts. Under the terms of these agreements, Marketing & Trading is obligated to deliver natural gas to meet CG&E's and **ULH&P's** requirements. Payments under these agreements for the years ended December 31, 2005 and 2004 were approximately $102 million and $79 million, for **ULH&P**. These amounts are recorded in the Statements of Income for CG&E and **ULH&P** as *Operation Expenses*.

ULH&P terminated its agreement with Marketing & Trading, and on December 29, 2005, entered into an agreement with an unrelated third party to manage their interstate pipeline transportation, storage capacity, and gas supply contracts.

ULH&P participates in a money pool arrangement with Cinergy Corp., Services, PSI and CG&E and their subsidiaries to better manage cash and working capital requirements. These amounts are reflected in **ULH&P's** Comparative Balance Sheets as *Notes Payable to Associated Companies* (Account 233) and *Notes Receivable from Associated Companies* (Account 145). For a further discussion of the money pool agreement, see Note 6.

2. Pending Merger

On May 8, 2005, Cinergy Corp. entered into an agreement and plan of merger with Duke, a North Carolina corporation, whereby Cinergy Corp. will be merged with Duke. Under the merger agreement, each share of Cinergy Corp. common stock will be converted into 1.56 shares of the newly formed company, Duke Energy Holding.

The merger agreement has been approved by both companies' Boards of Directors. Consummation of the merger is subject to customary conditions, including, among others, the approval of the shareholders of both companies and the approvals of various regulatory authorities.

Immediately following consummation of the merger, former Cinergy shareholders will own approximately 24 percent of Duke Energy Holding's common stock. Paul Anderson, Duke's CEO and Chairman of the Board will remain Chairman of the combined company and Jim Rogers, Cinergy's CEO and Chairman of the Board, will become the President and CEO of the combined company. The new Duke Energy Holding board will be comprised of 10 members appointed by Duke and five members appointed by Cinergy.

The merger will be recorded using the purchase method of accounting whereby the total purchase price of approximately $9 billion will be allocated to Cinergy's identifiable tangible and intangible assets acquired and liabilities assumed based on their fair values as of the closing of the merger.

The merger is expected to close in the first half of 2006. However, the actual timing is contingent on the receipt of several approvals including: FERC, Federal Communications Commission (FCC), Nuclear Regulatory Commission (NRC), state regulatory commissions of Ohio, Indiana, Kentucky, North Carolina, and South Carolina, and shareholders of each company. The status of these matters is as follows:

Completed:

- On August 11, 2005, the United States Department of Justice and the Federal Trade Commission granted early termination of the waiting period imposed by the Hart-Scott-Rodino Antitrust Improvements Act of 1976.
- In November 2005, the KPSC approved Duke's and Cinergy's application seeking approval of a transfer and acquisition of control of the Union Light, Heat and Power Company (ULH&P).
- In November 2005, the state utility regulatory agency in South Carolina approved Duke's application requesting authorization to enter into a business combination.
- In December 2005, the Public Utilities Commission of Ohio (PUCO) approved Cinergy's application of a change in control with respect to CG&E. The PUCO affirmed the approval in February 2006.
- In December 2005, the FERC approved Duke's and Cinergy's application requesting approval of the merger and the subsequent internal restructuring and consolidation of the merged company.
- In February 2006, the NRC approved Duke's application requesting approval of the merger.
- The FCC has approved assignment of all eight Cinergy wireless telecommunications licenses.
- In light of the repeal of the PUHCA 1935, as amended, effective February 2006, the merger will no longer require SEC authorization under the PUHCA 1935.
- In March 2006, the shareholders of both companies voted to approve the merger.
- In March 2006, the IURC approved an agreement resolving all issues related to the commission's review of Cinergy's planned merger with Duke.
- In March 2006, the North Carolina Utility Regulatory Commission issued an order approving the merger, subject to several regulatory conditions. In March 2006, Duke and Cinergy accepted the regulatory conditions set forth in the order.

The merger agreement also provides that Duke and Cinergy will use their reasonable best efforts to transfer five generating stations located in the midwest from Duke to CG&E. This transfer will require regulatory approval by the FERC and, with respect to one plant located in Indiana the IURC. The FERC approved this transaction in December 2005. CG&E and the Duke affiliate that owns the interest in the Indiana plant filed an application with the IURC requesting approval for the transfer (as well as the declination by the IURC of jurisdiction over CG&E following the transfer) in October 2005. A final order approving the transfer and the IURC's declination of jurisdiction over CG&E was received in February 2006. Duke and Cinergy intend to effectuate the transfer as an equity infusion into CG&E at book value. In conjunction with the transfer, Duke Capital LLC, a subsidiary of Duke, and CG&E intend to enter into a financial arrangement covering a multi-year period, to eliminate any potential cash shortfalls that may result from CG&E owning and operating the five stations. At this time, we cannot predict the outcome of this matter.

The merger agreement contains certain termination rights for both Duke and Cinergy, and further provides that, upon termination of the merger agreement under specified circumstances, a party would be required to pay the other party's fees and expenses in an amount not to exceed $35 million and/or a termination fee of $300 million in the case of a fee payable by Cinergy to Duke or a termination fee of $500 million in the case of a fee payable by Duke to Cinergy. Any termination fee would be reduced by the amount of any fees and expenses previously reimbursed by the party required to pay the termination fee.

In May 2005, a purported shareholder class action was filed in the Court of Common Pleas in Hamilton County, Ohio against Cinergy and each of the members of the Board of Directors. The lawsuit alleged that the defendants breached their duties of due care and loyalty to shareholders by agreeing to the merger agreement between Duke and Cinergy and was seeking to either enjoin or amend the terms of the merger. Cinergy and the individual defendants filed a motion to dismiss this lawsuit in July 2005, which was granted in November of 2005. An appeal was not filed by the plaintiffs and the case is closed.

Although Management believes that the merger should close in the first half of 2006, the actual timing of the transaction could be delayed or the merger could be abandoned by the parties in the event of the inability to obtain one or more of the required regulatory approvals on acceptable terms.

3. Common Stock

(a) Common Stock Outstanding

CG&E holds all of the **ULH&P's** common stock.

(b) Merger-Related Obligations

Several of the company's benefit plans contain "change-in-control" clauses that provide enhanced, and/or accelerate the payment of, benefits to management level employees in the event of a qualifying transaction such as would occur upon the consummation of the proposed merger with Duke as discussed in Note 2. These include benefits paid pursuant to the Long-Term Incentive Compensation Plan (LTIP) and certain payments under Cinergy's Annual Incentive Plan. Certain employees will also be entitled to additional severance and benefits in the event they are involuntarily terminated without "cause" or voluntarily terminate for "good reason" (as such terms are defined in their employment agreements) in connection with or following the merger.

On December 30, 2005, Cinergy entered into agreements with 28 employees to accelerate the payment of a portion of the amounts discussed above, otherwise expected to be paid after December 31, 2005, in order to mitigate the Company's taxes and related expenses. Payments totaling $70 million were made in December pursuant to these agreements. The agreements amend the employees' employment agreements, and benefit plans in which they participate, to accelerate into 2005 the payment of certain amounts that they have previously earned or are expected to earn after December 31, 2005. Among other things, the Company prepaid performance shares under the LTIP and severance payments for certain individuals. In the event an employee who received such amounts voluntarily terminates his employment prior to the closing of the merger, the employee is obligated to repay all of the payments, and if the merger does not close on or prior to December 15, 2006, the employee is obligated to repay half of the payments, to reflect his or her estimated tax liability upon receipt of the accelerated payments; in each case, less any amounts that the employee has already earned through such date. By accelerating these payments, the Company will mitigate taxes and related expenses that it would otherwise incur if it had waited until after 2005 to make these payments.

The majority of these payments have been recorded as prepaid compensation in *Prepayments*. Approximately half of these payments are being accounted for as a retention bonus and will be expensed over the period between January 1, 2006 and the estimated closing of the pending merger with Duke. The remainder, representing the half that executives must repay if the merger is never consummated, will remain in *Prepayments* until the merger closes.

In addition to payments made in December, based on certain assumptions and using our current best estimates, the Company's remaining contractual obligations that will be triggered upon merger consummation, and due shortly thereafter, including severance payments for those executives that have indicated their intention to terminate for "good reason", is expected to be approximately $73 million. These amounts will be accounted for when the merger closes. This estimate only includes amounts payable pursuant to existing benefit arrangements and employment contracts and does not include the value of accelerated stock options, retirement benefits owned prior to the merger, and amounts payable under severance plans that Duke and Cinergy are considering to reduce redundant positions after the merger closes.

4. Sales of Accounts Receivable

In February 2002, CG&E, PSI, and **ULH&P** entered into an agreement to sell certain of their accounts receivable and related collections. Cinergy Corp. formed Cinergy Receivables Company, LLC (Cinergy Receivables) to purchase, on a revolving basis, nearly all of the retail accounts receivable and related collections of CG&E, PSI, and **ULH&P**. Cinergy Corp. does not consolidate Cinergy Receivables since it meets the requirements to be accounted for as a qualifying special purpose entity. The transfers of receivables are accounted for as sales, pursuant to SFAS No. 140, *Accounting for Transfer and Servicing of Financial Assets and Extinguishments of Liabilities – a replacement of FASB Statement No. 125* (Statement 140).

The proceeds obtained from the sales of receivables are largely cash but do include a subordinated note from Cinergy Receivables for a portion of the purchase price (typically approximates 25 percent of the total proceeds). The note is subordinate to senior loans that Cinergy Receivables obtains from commercial paper conduits controlled by unrelated financial institutions. Cinergy Receivables provides credit enhancement related to senior loans in the form of over-collateralization of the purchased receivables. However, the over-collateralization is calculated monthly and does not extend to the entire pool of receivables held by Cinergy Receivables at any point in time. As such, these senior loans do not have recourse to all assets of Cinergy Receivables. These loans provide the cash portion of the proceeds paid to CG&E, PSI, and **ULH&P**.

This subordinated note is a retained interest (right to receive a specified portion of cash flows from the sold assets) under Statement 140 and is classified within *Notes Receivable from Associated Companies* in the accompanying Comparative Balance Sheets of **ULH&P**. In addition, Cinergy Corp.'s investment in Cinergy Receivables constitutes a purchased beneficial interest (purchased right to receive specified cash flows, in our case residual cash flows), which is subordinate to the retained interests held by CG&E, PSI, and **ULH&P**. The carrying values of the retained interests are determined by allocating the carrying value of the receivables between the assets sold and the interests retained based on relative fair value. The key assumptions in estimating fair value are credit losses and selection of discount rates. Because (a) the receivables generally turn in less than two months, (b) credit losses are reasonably predictable due to each company's broad customer base and lack of significant concentration, and (c) the purchased beneficial interest is subordinate to all retained interests and thus would absorb losses first, the allocated bases of the subordinated notes are not materially different than their face value. Interest accrues to CG&E, PSI, and **ULH&P** on the retained interests using the accretable yield method, which generally approximates the stated rate on the notes since the allocated basis and the face value are nearly equivalent. Cinergy Corp. records income from Cinergy Receivables in a similar manner. We record an impairment charge against the carrying value of both the retained interests and purchased beneficial interest whenever we determine that an other-than-temporary impairment has occurred (which is unlikely unless credit losses on the receivables far exceed the anticipated level).

The key assumptions used in measuring the retained interests are as follows (all amounts are averages of the assumptions used in sales during the period):

	2005	2004
Anticipated credit loss rate	**1.1%**	1.2%
Discount rate on expected cash flows	**5.7%**	3.8%
Receivables turnover rate(1)	**12.3%**	12.9%

(1) Receivables at each month-end divided by annualized sales for the month.

The hypothetical effect on the fair value of the retained interests assuming both a 10 percent and 20 percent unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history.

CG&E retains servicing responsibilities for its role as a collection agent on the amounts due on the sold receivables. However, Cinergy Receivables assumes the risk of collection on the purchased receivables without recourse to CG&E, PSI, and **ULH&P** in the event of a loss. While no direct recourse to CG&E, PSI, and **ULH&P** exists, these entities risk loss in the event collections are not sufficient to allow for full recovery of their retained interests. No servicing asset or liability is recorded since the servicing fee paid to CG&E approximates a market rate.

The following table shows the gross and net receivables sold, retained interests, purchased beneficial interest, sales, and cash flows during the periods ending December 31, 2005 and 2004.

	2005	2004
	(in millions)	
Receivables sold as of period end	$ 71	$ 54
Less: Retained interests	29	21
Net receivables sold as of period end	$ 42	$ 33
Purchased beneficial interest	$ -	$ -
Sales during period		
Receivables sold	$ 406	$ 367
Loss recognized on sale	6	4
Cash flows during period		
Cash proceeds from sold receivables	$ 392	$ 360
Collection fees received	-	-
Return received on retained interests	2	2

5. Long-Term Debt

		December 31 2005	2004
		(dollars in thousands)	
Other Long-term Debt:			
6.50	% Debentures due April 30, 2008	$ 20,000	$ 20,000
7.65	% Debentures due July 15, 2025	15,000	15,000
7.875	% Debentures due September 15, 2009	20,000	20,000
5.00	% Debentures due December 15, 2014	40,000	40,000
Total Other Long-term Debt		95,000	95,000
Unamortized Premium and Discount - Net		(591)	(660)
Total Long-term Debt		$ 94,409	$ 94,340

In December 2004, **ULH&P** issued $40 million principal amount of its 5.00% Debentures due December 15, 2014 (effective interest rate of 5.26%). Proceeds from this issuance were used for general corporate purposes and the repayment of outstanding indebtedness.

In January 2006, **ULH&P** assumed responsibility for principal and interest payments on $61 million of CG&E's long-term pollution control bonds in conjunction with the transfer of certain generating assets to **ULH&P**. The bonds will still remain on CG&E's balance sheet and **ULH&P's** obligation will be reflected as an intercompany note payable from **ULH&P** to CG&E. See Note 12 for additional information.

In January 2006, **ULH&P** assumed responsibility for principal and interest payments on $16 million of CG&E's redeemable variable rate pollution control bonds in conjunction with the transfer of certain generating assets to **ULH&P**. The bonds will still remain on CG&E's balance sheet and **ULH&P's** obligation will be reflected as an intercompany note payable from **ULH&P** to CG&E. See Note 12 for additional information.

The following table reflects the long-term debt maturities for **ULH&P** excluding any redemptions due to the exercise of call provisions or capital lease obligations. Callable means we have the right to buy back a given security from the holder at a specified price before maturity.

	Long-term Debt Maturities
	(in millions)
2006	$ -
2007	-
2008	20
2009	20
2010	-
Thereafter	55
Total	$ 95

6. Notes Payable and Other Short-term Obligations

(a) Short-term Notes

In September 2005, Cinergy Corp., CG&E, PSI, and **ULH&P** entered into a five-year revolving credit facility with a termination date of September 2010, which can be extended twice, each extension for an additional one-year period. The new credit agreement replaces two existing credit agreements, one dated April 2004 and one dated December 2004.

The new credit agreement provides that the pending merger between Duke and Cinergy Corp. will not be considered a fundamental change or a "Change of Control" for purposes of the credit agreement.

For purposes of making borrowings the new credit agreement does not require certain environmental, legal or material adverse change representations and warranties that were in the credit agreements it replaced.

ULH&P has a $100 million borrowing sublimit on this facility which was increased from $65 million in conjunction with its transaction with CG&E in which **ULH&P** acquired interests in three of CG&E's electric generating stations. See Note 12 for further information regarding this transaction.

(b) Money Pool

ULH&P participates in a money pool arrangement to better manage cash and working capital requirements. Under this arrangement, those companies with surplus short-term funds provide short-term loans to affiliates (other than Cinergy Corp.) participating under this arrangement. This surplus cash may be from internal or external sources. The amounts outstanding under this money pool arrangement are shown as a component of *Notes Receivable from Associated Companies* and/or *Notes Payable to Associated Companies* on the Comparative Balance Sheets of **ULH&P**. Any money pool borrowings outstanding reduce the unused and available short-term debt regulatory authority of **ULH&P**. **ULH&P** had money pool borrowings of $30 million and $11 million at December 31, 2005 and December 31, 2004, respectively.

7. Leases

(a) Operating Leases

Cinergy, including **ULH&P**, has entered into operating lease agreements for various facilities and properties such as computer, communication and transportation equipment, and office space. **ULH&P's** total rental payments on operating leases for years ended December 31, 2005 and 2004 were $2 million and $4 million, respectively. **ULH&P's** annual future minimum lease payment required for these operating leases are immaterial.

(b) Capital Leases

In each of the years 1999 through 2005, **ULH&P** entered into capital lease agreements to fund the purchase of gas and electric meters, and associated equipment. The lease terms are for 120 months commencing with the date of purchase and contain buyout options ranging from 105 to 108 months. The first buyout will occur in December 2008 and each year thereafter. It is **ULH&P's** objective to own the meters and associated equipment indefinitely and **ULH&P** plans to exercise the buyout option at month 105. As of December 31, 2005, Cinergy's effective interest rate on capital lease obligations outstanding was 6.1 percent. The meters and associated equipment are depreciated at the same rate as if owned by **ULH&P**. **ULH&P** recorded a capital lease obligation on its Comparative Balance Sheets.

ULH&P's total minimum lease payments and the present values for these capital lease items are shown below:

	Total Minimum Lease Payments
	(in millions)
Total minimum lease payments[1]	$ 16
Less: amount representing interest	4
Present value of minimum lease payments	$ 12

[1]Annual minimum lease payments are immaterial.

8. Financial Instruments

(a) Fair Value of Financial Instruments

The estimated fair values of **ULH&P's** financial instruments were as follows (this information does not claim to be a valuation of the companies as a whole):

	December 31, 2005		December 31, 2004	
Financial Instruments	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
	(in millions)			
ULH&P				
Other long-term debt	$ 94	$ 96	$ 94	$ 99

The following methods and assumptions were used to estimate the fair values of each major class of instruments:

(i) Cash and working funds

Due to the short period to maturity, the carrying amounts reflected on **ULH&P's** Comparative Balance Sheets approximate fair values.

(ii) Long-term debt

The fair values of long-term debt issues were estimated based on the latest quoted market prices or, if not listed on the New York Stock Exchange, on the present value of future cash flows. The discount rates used approximate the incremental borrowing costs for similar instruments.

(b) Credit Risk

Credit risk is the exposure to economic loss that would occur as a result of nonperformance by counterparties, pursuant to the terms of their contractual obligations. Specific components of credit risk include counterparty default risk, collateral risk, concentration risk, and settlement risk.

Our concentration of credit risk with respect to **ULH&P's** trade accounts receivable from electric and gas retail customers is limited. The large number of customers and diversified customer base of residential, commercial, and industrial customers significantly reduces **ULH&P's** credit risk. At December 31, 2005, we believe the likelihood of significant losses associated with credit risk in our trade accounts receivable or physical power portfolio is remote.

9. Pension and Other Postretirement Benefits

Cinergy Corp., including **ULH&P**, sponsors both pension and other postretirement benefit plans.

Cinergy's qualified defined benefit pension plans cover substantially all United States employees meeting certain minimum age and service requirements. During 2002, eligible Cinergy employees were offered the opportunity to make a one-time election, effective January 1, 2003, to either continue to have their pension benefit determined by the traditional defined benefit pension formula or to have their benefit determined using a cash balance formula. A similar election was provided to certain union employees at a later time.

The traditional defined benefit program utilizes a final average pay formula to determine pension benefits. These benefits are based on:

- years of participation;
- age at retirement; and
- the applicable average Social Security wage base.

Benefits are accrued under the cash balance formula based upon a percentage of pension eligible earnings plus interest. In addition, participants with the cash balance formula may request a lump-sum cash payment upon termination of their employment, which may result in increased cash requirements from pension plan assets. At the effective time of the election, benefits ceased accruing under the traditional defined benefit pension formula for employees who elected the cash balance formula. There was no change to retirement benefits earned prior to the effective time of the election. The pension benefits of all non-union and certain union employees hired after December 31, 2002 are calculated using the cash balance formula. At December 31, 2005, approximately 81 percent of Cinergy's employees remain in the traditional defined benefit program.

The introduction of the cash balance features to our defined benefit plans did not have a material effect on our financial position or results of operations.

Funding for the qualified defined benefit pension plans is based on actuarially determined contributions, the maximum of which is generally the amount deductible for tax purposes and the minimum being that required by the Employee Retirement Income Security Act of 1974, as amended. The pension plans' assets consist of investments in equity and debt securities.

Cinergy's investment strategy with respect to pension assets is designed to achieve a moderate level of overall portfolio risk in keeping with our desired risk objective, which is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The portfolio's target asset allocation is 60 percent equity and 40 percent debt with specified allowable ranges around these targets. Within the equity segment, we are broadly diversified across domestic, developed international and emerging market equities, with the largest concentration being domestic. Further diversification is achieved through allocations to growth/value and small-, mid-, and large-cap equities. Within the debt segment, we principally maintain separate "core plus" and "core" portfolios. The "core plus" portfolio makes tactical use of the "plus" sectors (e.g., high yield, developed international, emerging markets, etc.) while the "core" portfolio is a domestic, investment grade portfolio. In late 2004, Cinergy commenced the implementation of alternative investment strategies in its investment program. The initial allocation incorporated an investment in a hedge fund of funds in conjunction with an S&P 500 swaps and futures overlay program and is classified as part of our large-cap United States equity allocation. In 2005, a commitment was made to a private equity fund of funds with funding expected to occur over an approximate three-year period. Fund of funds are limited partnership vehicles that allocate invested capital to underlying funds (e.g. hedge funds or private equity) that pursue various investment strategies. Other than the hedge fund of funds strategy, the use of derivatives is currently limited to collateralized mortgage obligations and asset-backed securities. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

Cinergy uses a September 30 measurement date for its defined benefit pension plans. The asset allocation at September 30, 2005 and 2004 by asset category was as follows:

Asset Category	Percentage of Fair Value of Plan Assets at September 30 2005	2004
Equity securities(1)	62 %	62 %
Debt securities(2)	37 %	38 %
Cash	1 %	- %

(1) The portfolio's target asset allocation is 60 percent equity with an allowable range of 50 percent to 70 percent.

(2) The portfolio's target asset allocation is 40 percent debt with an allowable range of 30 percent to 50 percent.

In addition, Cinergy Corp. sponsors non-qualified pension plans (plans that do not meet the criteria for certain tax benefits) that cover officers, certain other key employees, and non-employee directors. We began funding certain of these non-qualified plans through a rabbi trust in 1999. This trust, which consists of equity (64 percent) and debt (36 percent) securities at December 31, 2005, is not restricted to the payment of plan benefits and therefore, not considered plan assets under Statement 87. Trust assets were approximately $10 million, for both the years ended December 31, 2005 and 2004, and are reflected in Cinergy's Balance Sheets as other investments.

Cinergy Corp. provides certain health care and life insurance benefits to retired United States employees and their eligible dependents. These benefits are subject to minimum age and service requirements. The health care benefits include medical coverage, dental coverage, and prescription drugs and are subject to certain limitations, such as deductibles and co-payments. Neither CG&E nor **ULH&P** pre-fund their obligations for these postretirement benefits. In 1999, PSI began pre-funding its obligations through a grantor trust as authorized by the IURC. This trust, which consists of equity (65 percent) and debt (35 percent) securities at December 31, 2005, is not restricted to the payment of plan benefits and therefore, not considered plan assets under Statement 106. At December 31, 2005 and 2004, trust assets were approximately $74 million and $71 million, respectively, and are reflected in Cinergy's Balance Sheets as other investments.

Qualified pension benefit contributions for 2005 were $102 million. Based on preliminary estimates, we expect 2006 contributions of approximately $120 million for qualified pension benefits. As discussed previously, we do not hold "plan assets" as defined by Statement 87 and Statement 106 for our non-qualified pension plans and other postretirement benefit costs, and therefore contributions are equal to the benefit payments presented in the following table.

The following estimated benefits payments, which reflect future service, are expected to be paid:

	Qualified Pension Benefits	Non-Qualified Pension Benefits	Other Postretirement Benefits
		(in millions)	
2006	$ 79	$ 10	$ 25
2007	79	10	26
2008	81	10	27
2009	83	14	28
2010	86	10	29
Five years thereafter	508	56	166

Cinergy's benefit plans' costs for the past three years included the following components:

	Qualified Pension Benefits		Non-Qualified Pension Benefits		Other Postretirement Benefits	
	2005	2004	**2005**	2004	**2005**	2004
			(in millions)			
Service cost	$ **38**	$ 35	$ **6**	$ 5	$ **6**	$ 5
Interest cost	**96**	89	**7**	7	**23**	22
Expected return on plans' assets	**(88)**	(81)	**-**	-	**-**	-
Amortization of transition (asset) obligation	**-**	(1)	**-**	-	**1**	1
Amortization of prior service cost	**5**	5	**2**	2	**(1)**	-
Recognized actuarial gain	**8**	2	**2**	2	**11**	8
Voluntary early retirement costs (Statement 88)(1)	**-**	-	**-**	-	**-**	-
Net periodic benefit cost	$ **59**	$ 49	$ **17**	$ 16	$ **40**	$ 36

(1) SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits* (Statement 88).

The net periodic benefit cost for ULH&P for the years ended December 31, 2005 and 2004, was as follows:

	Qualified Pension Benefits		Non-Qualified Pension Benefits		Other Postretirement Benefits	
	2005	2004	**2005**	2004	**2005**	2004
			(in millions)			
ULH&P	$ **1**	$ 1	$ **-**	$ -	$ **1**	$ 1

The following table provides a reconciliation of the changes in the plans' benefit obligations and fair value of assets for 2005 and 2004, and a statement of the funded status for both years. Cinergy uses a September 30 measurement date for its defined benefit pension plans and other postretirement benefit plans.

	Qualified Pension Benefits		Non-Qualified Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004	2005	2004
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of period	$ **1,578**	$ 1,458	$ **120**	$ 108	$ **409**	$ 399
Service cost	**38**	35	**6**	5	**6**	5
Interest cost	**96**	88	**7**	7	**23**	22
Amendments	**(1)**	(1)	**3**	8	**(1)**	(24)
Actuarial (gain) loss	**120**	69	**19**	-	**(3)**	27
Benefits paid	**(80)**	(71)	**(8)**	(8)	**(20)**	(20)
Benefit obligation at end of period	**1,751**	1,578	**147**	120	**414**	409
Change in plan assets						
Fair value of plan assets at beginning of period	**1,021**	877	**-**	-	**-**	-
Actual return on plan assets	**127**	98	**-**	-	**-**	-
Employer contribution	**102**	117	**8**	8	**19**	20
Benefits paid	**(81)**	(71)	**(8)**	(8)	**(19)**	(20)
Fair value of plan assets at end of period	**1,169**	1,021	**-**	-	**-**	-
Funded status	**(582)**	(557)	**(147)**	(120)	**(414)**	(409)
Unrecognized prior service cost	**24**	30	**19**	19	**(2)**	(2)
Unrecognized net actuarial loss	**378**	304	**56**	38	**175**	189
Unrecognized net transition (asset) obligation	**-**	-	**-**	-	**2**	4
Employer contribution	**-**	-	**2**	2	**6**	5
Accrued benefit cost at December 31	$ **(180)**	$ (223)	$ **(70)**	$ (61)	$ **(233)**	$ (213)
Amounts recognized in balance sheets						
Accrued benefit liability	$ **(366)**	$ (366)	$ **(130)**	$ (109)	$ **(233)**	$ (213)
Intangible asset	**24**	30	**19**	19	**-**	-
Accumulated other comprehensive income (pre-tax)	**162**	113	**41**	29	**-**	-
Net recognized at end of period	$ **(180)**	$ (223)	$ **(70)**	$ (61)	$ **(233)**	$ (213)

The accumulated benefit obligation for the qualified defined benefit pension plans was approximately $1,535 million and approximately $1,387 million for 2005 and 2004, respectively. The accumulated benefit obligation for the non-qualified defined benefit pension plans was approximately $132 million and $111 million for 2005 and 2004, respectively.

The weighted-average assumptions used to determine benefit obligations were as follows:

	Qualified Pension Benefits		Non-Qualified Pension Benefits		Other Postretirement Benefits	
	2005	2004	2005	2004	2005	2004
Discount rate	**5.75 %**	6.25 %	**5.75 %**	6.25 %	**5.50 %**	5.75 %
Rate of future compensation increase	**4.00**	4.00	**4.00**	4.00	**N/A**	N/A

The weighted-average assumptions used to determine net periodic benefit cost for the years ended December 31, 2005 and 2004 were as follows:

	Qualified Pension Benefits		Non-Qualified Pension Benefits		Other Postretirement Benefits	
	2005	2004	**2005**	2004	**2005**	2004
Discount rate	**5.75 %**	6.25 %	**5.75 %**	6.25 %	**5.50 %**	6.25 %
Expected return on plans' assets	**8.50**	8.50	**N/A**	N/A	**N/A**	N/A
Rate of future compensation increase	**4.00**	4.00	**4.00**	4.00	**N/A**	N/A

Our discount rate is determined by matching the anticipated payouts under our pension and postretirement plans to the rates from a hypothetical spot rate yield curve. The curve is created by deriving the rates for hypothetical zero coupon bonds from high-yield double A coupon bonds of varying maturities. Non-callable bonds and outliers (defined as bonds with yields outside of two standard deviations from the mean) are excluded in computing the yield curve.

The calculation of Cinergy's expected long-term rate of return is a two-step process. Capital market assumptions (e.g., forecasts) are first developed for various asset classes based on underlying fundamental and economic drivers of performance. Such drivers for equity and debt instruments include profit margins, dividend yields, and interest paid for use of capital. Risk premiums for each asset class are then developed based on factors such as expected liquidity, credit spreads, inflation uncertainty and country/currency risk. Current valuation factors such as present interest and inflation rate levels underpin this process.

The assumptions are then modeled via a probability based multi-factor capital market methodology. Through this modeling process, a range of possible 10-year annualized returns are generated for each strategic asset class. Those returns falling at the 50th percentile are utilized in the calculation of Cinergy's expected long-term rate of return.

The assumed health care cost trend rates were as follows:

	2005	2004
Health care cost trend rate assumed for next year	**7.00 %**	8.00 %
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	**5.00 %**	5.00 %
Year that the rate reaches the ultimate trend rate	**2008**	2008

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. Our health care cost trend is calculated using healthcare inflation rates, Gross Domestic Product growth, Medicare integration, allowances for plan design variables, and other cost drivers. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
	(in millions)	
Effect on total of service and interest cost components	$ 4	$ (4)
Effect on APBO	47	(42)

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act introduced a prescription drug benefit to retirees as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is actuarially equivalent to the benefit provided by Medicare. We believe that our coverage for prescription drugs is at least actuarially equivalent to the benefits provided by Medicare for most current retirees because our benefits for that group substantially exceed the benefits provided by Medicare, thereby allowing us to qualify for the subsidy. We have accounted for the subsidy as a reduction of our APBO. The APBO was reduced by approximately $17 million and will be amortized as an actuarial gain over future periods, thus reducing future benefit costs. The impact on our 2004 and 2005 net periodic benefit cost was not material. Our accounting treatment for the subsidy is consistent with FASB Staff Position No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.*

In January 2004, Cinergy, including **ULH&P**, announced to employees the creation of a new retiree Health Reimbursement Account (HRA) option, which will impact the postretirement healthcare benefits provided by Cinergy. HRAs are bookkeeping accounts that can be used to pay for qualified medical expenses after retirement. The majority of employees had the opportunity during the Fall of 2004 to make a one-time election to remain in Cinergy's current retiree healthcare program or to move to the new HRA option. Approximately 40 percent of Cinergy's employees elected the new HRA option. The HRA option has no effect on current retirees receiving postretirement benefits from Cinergy. As is the case under the current retiree health program, employees who participate in the HRA option, generally, will become eligible to receive their HRA benefit only upon retirement on or after the age of 50 with at least five years of service. We expect that the impact of the new HRA option will not be material to **ULH&P's** other postretirement benefit costs.

10. Income Taxes

The following table shows the significant components of **ULH&P's** *Accumulated Deferred Income Taxes* asset (Account 190) and liability (Account 281, 282 and 283) as of December 31:

	ULH&P	
	2005	2004
	(in millions)	
Deferred Income Tax Liability		
Utility plant	$ 58	$ 63
Other	1	2
Total Deferred Income Tax Liability	59	65
Deferred Income Tax Asset	6	7
Net Deferred Income Tax Liability	$ 53	$ 58

Cinergy and its subsidiaries, including **ULH&P**, file a consolidated federal income tax return and combined/consolidated state and local tax returns in certain jurisdictions. The corporate taxable income method is used to allocate tax benefits to the subsidiaries, including **ULH&P**, whose investments or results of operations provide those tax benefits. Any tax liability not directly attributable to a specific subsidiary is allocated proportionately among the subsidiaries, including **ULH&P**, as required by the agreement.

The following table summarizes federal and state income taxes charged (credited) to income for **ULH&P**:

	2005	2004
	(in millions)	
Current Income Taxes		
Federal	$ 5	$ 3
State	1	-
Total Current Income Taxes	$ 6	$ 3
Deferred Income Taxes		
Federal		
Depreciation and other property, plant, and equipment-related items	$ (4)	$ 7
Pension and other postretirement benefit costs	1	-
Fuel costs	1	(1)
Other-net	3	-
Total Deferred Federal Income Taxes	$ 1	$ 6
State	1	1
Total Deferred Income Taxes	$ 2	$ 7
Total Income Taxes	$ 8	$ 10

The following table presents a reconciliation of federal income taxes (which are calculated by multiplying the statutory federal income tax rate by book income before federal income tax) to the federal income tax expense reported in the Statements of Income for **ULH&P**.

	2005	2004
	(in millions)	
Statutory federal income tax provision	$ 7	$ 9
Increases (reductions) in taxes resulting from:		
Depreciation and other property, plant, and equipment-related differences	(1)	-
Federal Income Tax Expense	$ 6	$ 9

In January 2006, **ULH&P** completed the acquisition of certain generating assets of CG&E. The asset transfer, which occurred at net book value, will increase the net deferred income tax liabilities related to these assets by approximately $7.4 million over the net deferred tax liabilities recognized by CG&E as the result of the change in tax jurisdictions. See Note 12 for additional information on the transfer.

11. Commitments and Contingencies

(a) Regulatory - ULH&P Gas Rate Case

In 2002, the KPSC approved **ULH&P's** gas base rate case requesting, among other things, recovery of costs associated with an accelerated gas main replacement program of up to $112 million over ten years. The approval allowed the costs to be recovered through a tracking mechanism for an initial three-year period expiring on September 30, 2005, with the possibility of renewal for up to ten years. The tracking mechanism allows **ULH&P** to recover depreciation costs and rate of return annually over the life of the assets. As of December 31, 2005, we have capitalized $61 million in costs associated with the accelerated gas main replacement program through this tracking mechanism, of which **ULH&P** has recovered $8.9 million. The Kentucky Attorney General has appealed to the Franklin Circuit Court the KPSC's approval of the tracking mechanism and the tracking mechanism rates. In October 2005, both the

Company and the KPSC filed with the Franklin Circuit Court, requesting dismissal of the case for failure to prosecute by the Kentucky Attorney General. At the present time, **ULH&P** cannot predict the timing or outcome of this litigation.

In February 2005, **ULH&P** filed a gas base rate case with the KPSC requesting approval to continue the tracking mechanism in addition to its request for a $14 million annual increase in base rates. A portion of the increase is attributable to including recovery of the current cost of the accelerated main replacement program in base rates. The KPSC did not rule on the base rate case request or the request to continue the tracking mechanism by October 1, 2005; consequently the initial tracking mechanism expired on September 30, 2005. In accordance with Kentucky law, **ULH&P** implemented the full amount of the requested rate increase on October 1, 2005. In December 2005, the KPSC approved an annual rate increase of $8.1 million and reapproved the tracking mechanism through 2011. Pursuant to the KPSC's order, **ULH&P** filed a refund plan in January 2006 for the excess revenues collected since October 1, 2005. In February 2006, the KPSC issued an additional order responding to a rehearing request made by the Attorney General. Its rehearing order approved the Company's refund plan which will result in refunds being provided to customers beginning in March 2006. In February 2006, the Attorney General appealed the KPSC's order to the Franklin Circuit Court, claiming that the order improperly allows **ULH&P** to increase its rates for gas main replacement costs in between general rate cases, and also claiming that the order improperly allows **ULH&P** to earn a return on investment for the costs recovered under the tracking mechanism which permits **ULH&P** to recover its gas main replacement costs. At this time, **ULH&P** cannot predict the outcome of this litigation

(b) Other - Construction and Other Commitments

Forecasted construction and other committed expenditures for the year 2006 and for the five-year period 2006-2010 (in nominal dollars) are $67 million and $292 million, respectively.

12. Subsequent Event

In January 2006, **ULH&P** completed the transfer from CG&E of CG&E's approximately 69 percent ownership interest in the East Bend Station, located in Boone County, Kentucky, the Woodsdale Station, located in Butler County, Ohio, and one generating unit at the four-unit Miami Fort Station, located in Hamilton County, Ohio, and associated transactions. The transaction was effective as of January 1, 2006 at net book value. The final required regulatory approval was received in November 2005 from the SEC under the PUHCA of 1935. The KPSC and the FERC had earlier issued orders approving aspects of the transaction. The transaction will not affect current retail electric rates for **ULH&P's** customers. Updated rates are expected to be implemented January 1, 2007 pursuant to a rate case to be filed in 2006 that incorporates the value of these assets into **ULH&P's** rate base.

In connection with the transfer of these assets, **ULH&P** accepted a capital contribution from CG&E and assumed certain liabilities of CG&E. In particular, **ULH&P** agreed to assume from CG&E all payment, performance, and other obligations of CG&E, with respect to (i) certain tax-exempt pollution control debt currently shown on the balance sheet of CG&E, (ii) certain of CG&E's outstanding *Accounts Payable to Associated Companies*, and (iii) certain deferred tax liabilities related to the assets. **ULH&P** intends to repay the tax-exempt obligations with the proceeds from the issuance of tax-exempt debt at **ULH&P**. The accounts payable obligations will be repaid initially with the proceeds from short-term borrowings and eventually through the issuance of long-term senior unsecured debentures. The following table summarizes this transaction for **ULH&P**:

		(in millions)
Assets Received		
Generating Assets	$	376
Inventory		24
Total Assets Received	$	400
Liabilities Assumed		
Debt	$	77
Accounts payable to affiliated companies		90
Deferred tax liabilities		91
Other		2
Total Liabilities Assumed	$	260
Contributed Capital from CG&E	$	140

As part of this transaction, CG&E and **ULH&P** terminated the long-term wholesale power contract under which CG&E had previously supplied power to **ULH&P**. Further, CG&E also proposed to supply and **ULH&P** agreed to purchase back-up power from CG&E for planned and unplanned outages of the three generating plants through December 31, 2009 pursuant to a draft contract. The parties never executed this draft contract and **ULH&P** currently purchases back-up power, when needed, through the Midwest ISO energy markets. Given changes in circumstances, including the implementation of the Midwest ISO Energy Markets Tariff, CG&E and **ULH&P** are planning to propose an alternative arrangement for supplying back-up power to **ULH&P**. At this time, whether and the conditions under which the KPSC may allow **ULH&P** to recover any increased costs for an alternative arrangement for the supply of back-up power are unknown and CG&E and **ULH&P** cannot determine the magnitude of any potential increased costs for back-up power.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

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		(489,193)		32
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		(796,621)		(32)
4	Total (lines 2 and 3)		(796,621)		(32)
5	Balance of Account 219 at End of Preceding Quarter/Year		(1,285,814)		
6	Balance of Account 219 at Beginning of Current Year		(1,285,814)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		(1,036,995)		
9	Total (lines 7 and 8)		(1,036,995)		
10	Balance of Account 219 at End of Current Quarter/Year		(2,322,809)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(489,161)		
2					
3			(796,653)		
4			(796,653)	18,638,218	17,841,565
5			(1,285,814)		
6			(1,285,814)		
7					
8			(1,036,995)		
9			(1,036,995)	14,645,105	13,608,110
10			(2,322,809)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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 (f) 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)	493,800,857	278,153,947
4	Property Under Capital Leases	11,231,335	3,558,486
5	Plant Purchased or Sold		
6	Completed Construction not Classified	97,591,605	17,315,152
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	602,623,797	299,027,585
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	12,840,088	6,270,174
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	615,463,885	305,297,759
14	Accum Prov for Depr, Amort, & Depl	214,273,344	115,887,996
15	Net Utility Plant (13 less 14)	401,190,541	189,409,763
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	203,426,341	114,606,622
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	10,847,003	1,281,374
22	Total In Service (18 thru 21)	214,273,344	115,887,996
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)	214,273,344	115,887,996

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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
191,126,058				24,520,852	3
5,572,849				2,100,000	4
					5
80,208,985				67,468	6
					7
276,907,892				26,688,320	8
					9
					10
4,964,356				1,605,558	11
					12
281,872,248				28,293,878	13
87,196,852				11,188,496	14
194,675,396				17,105,382	15
					16
					17
86,175,683				2,644,036	18
					19
					20
1,021,169				8,544,460	21
87,196,852				11,188,496	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
87,196,852				11,188,496	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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	1,943,776	138,455
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	1,943,776	138,455
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)		
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

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 ounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of jondent'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
			2,082,231		4
			2,082,231		5
					6
					7
					8
					9
					10
					11
					12
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					14
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					43

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)		
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	1,121,636	-24,692
49	(352) Structures and Improvements	381,059	
50	(353) Station Equipment	10,271,858	783,729
51	(354) Towers and Fixtures		
52	(355) Poles and Fixtures	4,792,274	359,228
53	(356) Overhead Conductors and Devices	4,533,044	-149,496
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	21,099,871	968,769
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	7,307,310	252,772
61	(361) Structures and Improvements	296,659	47,303
62	(362) Station Equipment	30,230,829	2,894,143
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	42,343,487	1,313,159
65	(365) Overhead Conductors and Devices	56,595,652	5,712,666
66	(366) Underground Conduit	14,452,912	-96,639
67	(367) Underground Conductors and Devices	33,148,272	288,170
68	(368) Line Transformers	48,464,098	-54,671
69	(369) Services	9,109,090	1,809,807
70	(370) Meters	13,909,485	383,249
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises	9,647	
73	(373) Street Lighting and Signal Systems	6,141,672	1,295,549
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	262,009,113	13,845,508
76	5. GENERAL PLANT		
77	(389) Land and Land Rights		
78	(390) Structures and Improvements	39,190	-7,066
79	(391) Office Furniture and Equipment	37,021	
80	(392) Transportation Equipment	96,658	2,941
81	(393) Stores Equipment		
82	(394) Tools, Shop and Garage Equipment	470,883	-3,776
83	(395) Laboratory Equipment		
84	(396) Power Operated Equipment	47,352	
85	(397) Communication Equipment	84,462	
86	(398) Miscellaneous Equipment		
87	SUBTOTAL (Enter Total of lines 77 thru 86)	775,566	-7,901
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	775,566	-7,901
91	TOTAL (Accounts 101 and 106)	285,828,326	14,944,831
92	(102) Electric Plant Purchased (See Instr. 8)		
93	(Less) (102) Electric Plant Sold (See Instr. 8)		
94	(103) Experimental Plant Unclassified		
95	TOTAL Electric Plant in Service (Enter Total of lines 91 thru 94)	285,828,326	14,944,831

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					44
					45
					46
					47
			1,096,944		48
			381,059		49
78,856		-634,122	10,342,609		50
					51
36,647			5,114,855		52
20,039			4,363,509		53
					54
					55
					56
					57
135,542		-634,122	21,298,976		58
					59
6,014			7,554,068		60
34,703			309,259		61
156,622		1,017,512	33,985,862		62
					63
656,916		27,139	43,026,869		64
813,573		-1,814	61,492,931		65
22,393		18,799	14,352,679		66
199,633		-5,270	33,231,539		67
563,912		1,441,512	49,287,027		68
146,322			10,772,575		69
576,514		-36,081	13,680,139		70
					71
			9,647		72
241,327		17,045	7,212,939		73
					74
3,417,929		2,478,842	274,915,534		75
					76
					77
			32,124		78
1,003			36,018		79
			99,599		80
					81
511			466,596		82
					83
35,307			12,045		84
			84,462		85
					86
36,821			730,844		87
					88
					89
36,821			730,844		90
3,590,292		1,844,720	299,027,585		91
					92
					93
					94
3,590,292		1,844,720	299,027,585		95

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	RIGHT OF WAY - TURKEYFOOT - PT 3 - AUTUMN	127,166
2	BLACKWELL SUB - INSTALL AUTOTRANSFORMER AND TWO 69KV CIRCUITS	138,168
3	BEAVER SUB - REPLACE TB2 LEAKY RADIATORS	161,554
4	WILDER SUB - INSTALL CAPACITOR BANK ON 69KV BUS 2	167,813
5	UPGRADE OPS & CREW CENTRITITY SOFTWARE	314,461
6	DRY RIDGE SUB - PURCHASE 10-5 MVA 69-13KV WITH 2 EXITS	332,538
7	CINTI GEAR SUB - PURCHASE FROM NORTHERN KENTUCKY WATER DISTRICT	337,082
8	LONGBRAND 41 42 43 FEEDERS	371,339
9	THOMAS MORE - CONSTRUCT 22MVA SUBSTATION	456,331
10	VERONA SUB - REBUILD SUBSTATION	594,254
11	MT. ZION - CONSTRUCT NEW SUBSTATION	679,008
12	THOMAS MORE SUB - 224MVA SUBSTATION	726,887
13		
14	PROJECTS UNDER $100,000	1,863,573
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
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27		
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40		
41		
42		
43	TOTAL	6,270,174

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	109,287,213	109,287,213		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	9,200,984	9,200,984		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
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)	9,200,984	9,200,984		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	3,588,778	3,588,778		
13	Cost of Removal	742,965	742,965		
14	Salvage (Credit)	20,232	20,232		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	4,311,511	4,311,511		
16	Other Debit or Cr. Items (Describe, details in footnote):	429,936	429,936		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	114,606,622	114,606,622		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	9,553,345	9,553,345		
26	Distribution	105,017,589	105,017,589		
27	General	35,688	35,688		
28	TOTAL (Enter Total of lines 20 thru 27)	114,606,622	114,606,622		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) X An Original (2) _ A Resubmission	/ /	2005/Q4

FOOTNOTE DATA

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

Transfers and Adjustments	457,686
Gain / Losses	(27,750)
Total Other Debit/Credit Items	429,936

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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); 'mates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
_. 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)	1,991,462	1,841,070	Gas
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)	351,387	362,283	Gas and Electric
6	Assigned to - Operations and Maintenance	32,853	33,871	Gas and Electric
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Assigned to - Other (provide details in footnote)			
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	384,240	396,154	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
15	Stores Expense Undistributed (Account 163)	21,322	20,743	Gas and Electric
6				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	2,397,024	2,257,967	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) X An Original (2) _ A Resubmission	/ /	2005/Q4

FOOTNOTE DATA

Schedule Page: 227 Line No.: 8 Column: b

$17,617 of lines 5 and 6 is attributable to Transmission Plant on line 8, column (c).

Schedule Page: 227 Line No.: 8 Column: c

$18,546 of lines 5 and 6 is attributable to Transmission Plant on line 8, column (c).

Schedule Page: 227 Line No.: 9 Column: b

$218,767 of lines 5 and 6 is attributable to Distribution Plant on line 9, column (c).

Schedule Page: 227 Line No.: 9 Column: c

$239,388 of lines 5 and 6 is attributable to Distribution Plant on line 9, column (c).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	STATEMENT OF FINANCIAL ACCOUNTING					
2	STANDARDS NO. 109: ACCOUNTING					
3	FOR INCOME TAXES	37,663,959	329,496		6,492,992	31,500,463
4	1992 WORKFORCE REDUCTION COSTS - GAS					
5	(AMORTIZED 36 MONTHS FEBRUARY 2002 -					
6	JANUARY 2005)	4,719		926	4,719	
7	1992 WORKFORCE REDUCTION COSTS -					
8	ELECTRIC	1,530,917				1,530,917
9	LIMITED EARLY RETIREMENT PROGRAM					
10	CASH COSTS - GAS (AMORTIZED 36 MONTHS					
11	FEBRUARY 2002 - JANUARY 2005)	5,022		930.2	5,022	
12	LIMITED EARLY RETIREMENT PROGRAM					
13	DELAYED CASH COSTS - GAS					
14	(AMORTIZED 120 MONTHS FEBRUARY 2002 -					
15	JANUARY 2012)	128,690		930.2	18,168	110,522
16	AMRP STUDY COSTS - GAS (AMORTIZED 120					
17	MONTHS FEBRUARY 2002 - JANUARY 2012)	226,950		928	32,040	194,910
18	DEMAND SIDE MANAGEMENT COSTS	1,425,409	2,350,030	916	4,425,131	-649,692
19	RATE CASE EXPENSES - GAS (AMORTIZED 36					
20	MONTHS FEBRUARY 2002 - JANUARY 2005)	7,259		928	7,259	
21	TRANSACTION COSTS - ACQUISITION OF					
22	GENERATION RESOURCES	538,367	72,390			610,757
23	ULH&P 2005 GAS RATE CASE	31,321	151,889		1,742	181,468
24	ULH&P 2005 ELECTRIC RATE CASE		27,010			27,010
25	ARO OTHER REGULATORY ASSET		5,196,675			5,196,675
26	2005 MERGER TRANSACTION COSTS		1,452,962			1,452,962
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	41,562,613	9,580,452		10,987,073	40,155,992

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

Accounts charged are 190, 254, 282, 283

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
For any deferred debit being amortized, show period of amortization in column (a)
Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, 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						
2						
3	MISC. DEFERRED DEBITS	-77,403	340,057	VARIOUS	181,627	81,027
4	ITEMS DEFERRED PENDING	390,192	74,199	VARIOUS	476,859	-12,468
5	INVESTIGATION					
6	INTANGIBLE ASSET - FAS 87	1,485,456		219	406,584	1,078,872
7	QUALIFIED PENSION					
8	BOND EXPENSES	11,692	223,082		2,933	231,841
9	LT LEASE RECEIVABLE		352,278			352,278
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
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39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	1,809,937				1,731,550

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2		3,637,099	1,722,462
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	3,637,099	1,722,462
9	Gas		
10		2,510,888	2,242,582
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	2,510,888	2,242,582
17	Other (Specify): Non Utility	857,354	2,278,499
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	7,005,341	6,243,543

Notes

Schedule Page: 234 Line No.: 17 Column: c

Form 1
Schedule Page: 234 Line No 17

	2005 Beginning Balance	2005 Ending Balance
Accum Deferred Income Tax	2,246	-
Minimum Pension Liability	870,507	1,478,843
MGB Hazardous Cleanup	-	799,656
Grantor Trust	(15,399)	-
	857,354	2,278,499

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock (Account 201)	1,000,000	15.00	
2				
3	Total Common Stock	1,000,000		
4				
5	Preferred Stock (Account 204)			
6				
7	Total Preferred Stock			
8				
9				
10				
11				
12				
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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.
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 AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
585,333	8,779,995					1
						2
585,333	8,779,995					3
						4
						5
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						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

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

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

Line No.	Item (a)	Amount (b)
1	Account 208 Donations Received from Stockholders	
2	Balance - Beginning of Year	4,772,609
3		
4	Contribution from Parent for Reallocation of Taxes	304,459
5		
6	Subtotal Balance - End of Year	5,077,068
7		
8		
9	Account 211 - Miscellaneous Paid - In Capital	
10	Balance - Beginning of Year (Sharesaver)	-156,194
11		
12	Subtotal Balance - End of Year (Sharesaver)	-156,194
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
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39		
40	TOTAL	4,920,874

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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 - NONE		
2			
3	ACCOUNTS 222 & 223 - NONE		
4			
5	ACCOUNT 224		
6	UNSECURED DEBENTURES:		
7	7.65% SERIES DUE IN 2025	15,000,000	904,818
8			295,650 D
9	6.50% SERIES DUE IN 2008	20,000,000	-221,976
10			169,400 D
11	5.00% SERIES DUE IN 2014	40,000,000	410,000
12			379,200 D
13	7.875% SERIES DUE IN 2009	20,000,000	170,547
14			51,600 D
15			
16	SUBTOTAL ACCOUNT 224	95,000,000	2,159,239
17			
18	SEE FOOTNOTE		
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	95,000,000	2,159,239

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 Debt - Credit.
.. 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
						5
						6
5/95	07/15/25	07/15/95	07/15/25	15,000,000	1,147,500	7
						8
04/30/98	04/30/08	04/30/98	04/30/08	20,000,000	1,300,000	9
						10
12/06/04	12/15/14	12/06/04	12/15/14	40,000,000	2,030,370	11
						12
09/15/99	09/15/09	09/15/99	09/15/09	20,000,000	1,575,000	13
						14
						15
				95,000,000	6,052,870	16
						17
						18
						19
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						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				95,000,000	6,052,870	33

Schedule Page: 256 Line No.: 18 Column: a

ULH&P'S SHELF REGISTRATION (NO. 333-127311) FILED WITH THE SECURITIES AND EXCHANGE COMMISSION ON OCTOBER 21, 2005, HAS $125M REMAINING SHELF CAPACITY. ON DECEMBER 17, 2004, ULH&P WAS GIVEN AUTHORITY TO ISSUE $500M OF LONG-TERM DEBT BY THE KPSC IN CAUSE NUMBER 2004-00435 WITH AN EXPIRATION DATE OF DECEMBER 31, 2006. THIS AUTHORITY HAS $500M REMAINING TO BE ISSUED. LONG-TERM DEBT AUTHORIZED UNDER ULH&P'S BOARD AUTHORITY ON SEPTEMBER 15, 2004, HAS $35M REMAINING TO BE ISSUED.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	14,645,105
2		
3		
4	Taxable Income Not Reported on Books	
5	Contributions in Aid of Construction	443,552
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	SEE FOOTNOTE FOR DETAILS	9,164,874
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	Allowance for Funds Used During Construction	813,205
16	Amortization of Investment Tax Credit	253,028
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	SEE FOOTNOTE FOR DETAILS	9,890,907
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	13,296,391
28	Show Computation of Tax:	
29	SEE FOOTNOTE	
30	*Taxable Income*	13,296,391
31		
32	Tax at 35%	4,653,737
33		
34	PLUS: ADJUSTMENTS OF PRIOR YEAR ACCRUALS - FIT	1,930,776
35	LESS: SERVICE COMPANY TAXES ALLOCATED - FIT	-1,166,099
36	LESS: CONTINGENCY ADJUSTMENTS	-426,887
37	LESS: ADJUSTMENTS OF CURRENT YEAR TAX CREDIT - FIT	-1,001
38		
39		
40	Total Current Provision	4,990,526
41		
42		
43		
44		

Schedule Page: 261 Line No.: 10 Column: b

Deductions Recorded on Books Not Deducted For Return:

Federal Income Tax	$6,482,682
State Income Tax	1,603,101
Others	1,079,091
Total	9,164,874

Schedule Page: 261 Line No.: 20 Column: b

Deductions on Return Not Charged Against Book Income:

Loss on Disposition of ACRS/MACRS Property	$1,554,068
Uncollectible Accounts Provision	2,548
Depreciation Deducted in Excess of Amount Booked	957,664
Duke Merger - Timing	5,084,498
Others	2,292,129
Total	9,890,907

Schedule Page: 261 Line No.: 40 Column: b

The respondent's taxable net income shown on line 30 will be included in the consolidated federal tax return of Cinergy Corp.

The 2005 consolidated tax and the allocation have not been finalized, but it is expected that ULHP's share of the consolidated taxes will equal its tax computed on a separate return basis.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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						
2	FEDERAL					
3						
4						
5	INCOME TAXES	-3,191,976		4,990,526		-3,831,915
6	FUEL TAXES	-4,615		10,164	4,988	561
7	FEDERAL INSURANCE	12,964		1,140,657	1,142,391	
8	UNEMPLOYMENT			13,819	13,819	
9						
10						
11	STATE					
12						
13	INCOME TAXES	2,123,745		680,988		2,005,239
14	FUEL TAXES	1,120		6,535	7,655	
15	UNEMPLOYMENT			9,857	9,857	
16	PROPERTY	15,596		801,707	761,301	
17	SALES AND USE TAX	403,879		207,104	778,106	-268,328
18	PUBLIC UTILITIES		284,771	578,105	586,669	
19	FRANCHISE			7,100	3,600	
20	LICENSE			305	305	
21						
22						
23	OTHER					
24						
25	PROPERTY	68,762		2,838,017	2,740,128	
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-570,525	284,771	11,284,884	6,048,819	-2,094,443

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2005/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 arentheses.
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 (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
						4
5,630,465		185,074			4,805,452	5
		8,094			2,070	6
11,230		555,498			585,159	7
		6,720			7,099	8
						9
						10
						11
						12
799,494		-136,933			817,921	13
		3,980			2,555	14
		4,793			5,064	15
56,002		382,023			419,684	16
101,205					207,104	17
	293,335				578,105	18
3,500		6,879			221	19
		249			56	20
						21
						22
						23
						24
166,651		1,405,640			1,432,377	25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
6,768,547	293,335	2,422,017			8,862,867	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) X An Original (2) _ A Resubmission	/ /	2005/Q4

FOOTNOTE DATA

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

Details of Federal Adjustments

Service Company Allocation	(953,654)
Consolidated Tax Allocation	(2,688,780)
Reclass Adjustment to Deferred Account	(189,481)
Total Federal Income Tax Adjustment	(3,831,915)

Schedule Page: 262 Line No.: 6 Column: f

Fuel Tax

Transportation Expense Clearing	561

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

State Income Tax

Consolidated Tax Allocation	2,005,239

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

Sales and Use

Sales and Use Tax	(268,328)

Schedule Page: 262 Line No.: 38 Column: l

Kind of Tax (Col. a)

Federal	**Other (1)**	**Gas Accounts 408.1-409.1**	**Other Accounts**
Income Taxes	4,805,452	2,921,096	1,884,356
Fuel Taxes	2,070	2,070	0
Federal Insurance Contribution	585,159	449,382	135,777
Unemployment	7,099	5,436	1,663
Superfund	0	0	0
State			
Incomes Taxes	817,921	669,258	148,663
Fuel Taxes	2,555	2,555	0
Unemployment	5,064	3,877	1,187
Property	419,684	419,684	0
Sales and Use Tax	207,104		207,104
Public Service Commission	578,105		578,105
Franchise	221	221	
License	56	56	0
Other			
City of Cincinnati	0	0	0
Property	1,432,377	1,432,377	0
Service Company Allocation	0	0	0
	8,862,867	5,906,012	2,956,855

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year 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%				411.4		
3	4%	4,186			411.4	2,987	
4	7%						
5	10%	1,108,882			411.4	173,461	
6							
7							
8	TOTAL	1,113,068				176,448	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas - 3%	43,827			411.4	7,450	
11	Gas - 4%	73,642			411.4	5,203	
12	Gas - 10%	1,395,251			411.4	63,927	
13							
14	TOTAL	1,512,720				76,580	
15							
16							
17							
18							
19							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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
1,199	30 YEARS		3
			4
935,421	30 YEARS		5
			6
			7
936,620			8
			9
36,377	43 YEARS		10
68,439	46 YEARS		11
1,331,324	45 YEARS		12
			13
1,436,140			14
			15
			16
			17
			18
			19
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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 $10,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	ADVANCE PAYMENTS					
2	GAS REFUNDS AND/OR					
3	RECONCILIATION DUE					
4	CUSTOMERS	127,434		904,785	453,023	-324,328
5	PENSION COST ADJUSTMENT	7,984,059		1,860,830	1,627,755	7,750,984
6	SUPPLEMENTAL PENSION-					
7	EXCESS PLAN	92,013		9,695	26,277	108,595
8	MISC. DEFERRED CREDITS					
9	AND OTHER	9,270		12,478		-3,208
10	ADDITIONAL MINIMUM PENSION					
11	LIABILITY-FAS 87 QUALIFIED					
12	PENSION	3,616,522			1,217,358	4,833,880
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
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44						
45						
46						
47	TOTAL	11,829,298		2,787,788	3,324,413	12,365,923

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	24,191,699	422,034	4,120,229
3	Gas	27,465,996	5,167,222	3,590,218
4	Other	12,255,759		
5	TOTAL (Enter Total of lines 2 thru 4)	63,913,454	5,589,256	7,710,447
6	Non-Utility Depreciation			
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	63,913,454	5,589,256	7,710,447
10	Classification of TOTAL			
11	Federal Income Tax	53,241,623	4,932,391	6,908,665
12	State Income Tax	10,671,831	656,865	801,782
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
		182	4,451,777	190, 283	13,572,587	29,614,314	2
		190, 283	2,049,738	182	2,267,852	29,261,114	3
		283	12,255,759				4
			18,757,274		15,840,439	58,875,428	5
		282	1,135,453			-1,135,453	6
							7
							8
			19,892,727		15,840,439	57,739,975	9
							10
		182, 190	12,672,964	182, 283	12,485,010	51,077,395	11
		182, 190	7,219,763	182, 283	3,355,429	6,662,580	12
							13

NOTES (Continued)

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

1. PURSUANT TO AGREEMENT REACHED IN FEDERAL ENERGY REGULATORY COMMISSION AUDIT FOR THE YEARS 1982 THRU 1985, THE RESPONDENT AGREED TO TRANSFER THE BALANCE AS OF DECEMBER 31, 1985 FOR CERTAIN PROPERTY RELATED ITEMS, (PAYROLL TAXES CAPITALIZED & ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION) FROM ACCOUNT 283-ACCUMULATED DEFERRED INCOME TAXES-OTHER TO ACCOUNT TO 282-ACCUMULATED DEFERRED INCOME TAXES-OTHER PROPERTY AND TO CONTINUE TO REFLECT SUCH ACTIVITY IN ACCOUNT 282.

2. BEGINNING IN JANUARY 1987, THE RESPONDENT, IN ACCORDANCE WITH THE TAX REFORM ACT OF 1986, BEGAN TO CAPITALIZE INTEREST FOR TAX PURPOSES ON REQUIRED PROJECTS. THE RESPONDENT DEFERRED IN ACCOUNT 282, THE FEDERAL AND STATE INCOME TAX EFFECTS OF THIS TIMING DIFFERENCE.

Schedule Page: 274 Line No.: 5 Column: b

1. BEGINNING IN 1987, IN ACCORDANCE WITH THE TAX REFORM ACT OF 1986, THE RESPONDENT INCLUDED IN TAXABLE INCOME AND TAX DEPRECIABLE PLANT AMOUNTS RECEIVED AS CONTRIBUTIONS IN AID OF CONSTRUCTION AND INCLUDED IN GAS TAXABLE INCOME AND GAS TAX DEPRECIABLE PLANT AMOUNTS RECEIVED AS CUSTOMER ADVANCES FOR CONSTRUCTION. PURSUANT TO KY PUBLIC SERVICE COMMISSION ORDER DATED APRIL 15, 1988 IN CASE NO. 313, THE RESPONDENT BEGAN INCLUDING IN GAS AND ELECTRIC TAXABLE INCOME AND TAX DEPRECIABLE PLANT AMOUNTS RECEIVED AS CONTRIBUTIONS IN AID OF CONSTRUCTION FOR GAS AND ELECTRIC OPERATIONS. THESE AMOUNTS WERE PREVIOUSLY RECOGNIZED IN NON-UTLITY OPERATIONS. THE NON-UTILITY BALANCE WAS TRANSFERRED TO THE GAS AND ELECTRIC ACCOUNT 282 BALANCES IN SEPTEMBER 1988. NONE OF THE ABOVE AMOUNTS ARE RECOGNIZED AS INCOME FOR FINANCIAL REPORTING PURPOSES. THE RESPONDENT DEFERRED, IN ACCOUNT 282, THE FEDERAL AND STATE INCOME TAX EFFECT OF THIS TIMING DIFFERENCE.

2. BEGINNING IN 1993, THE RESPONDENT BEGAN TO DEFER IN ACCOUNT 282, THE FEDERAL AND STATE INCOME TAX EFFECT OF FAS 109 WITH OFFSETTING ENTRIES TO REGULATORY ASSET AND REGULATORY LIABILITY ACCOUNTS.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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		1,186,391	-176,808	257,295
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	1,186,391	-176,808	257,295
10	Gas			
11		327,653	597,021	295,377
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	327,653	597,021	295,377
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,514,044	420,213	552,672
20	Classification of TOTAL			
21	Federal Income Tax	1,058,730	632,673	454,978
22	State Income Tax	455,314	-212,460	97,694
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
-721		236	189,481	190	268,127	830,213	3
		282	158,455			-158,455	4
							5
							6
							7
							8
-721			347,936		268,127	671,758	9
							10
1		190	660,936	282	663,637	631,999	11
							12
							13
							14
							15
							16
1			660,936		663,637	631,999	17
							18
-720			1,008,872		931,764	1,303,757	19
							20
-720		190, 236	496,414	190, 282	300,293	1,039,584	21
		190, 236	512,458	190, 282	631,471	264,173	22
							23

NOTES (Continued)

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

1. Beginning in 1993, the respondent began to defer in account 283, the federal and state income tax effect of FASB 109 with offsetting entries to regulatory asset and regulatory liability accounts.

2. Pursuant to KY Public Service Commission order in case no. 8373, the respondent began in July 1982 to defer in account 283 the federal and state income tax effect of deferred unrecovered purchased gas costs. Beginning in 1987, the respondent also began deferring the federal and state tax effects of book/tax timing differences of unrecovered fuel costs associated with unbilled revenue.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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.
inor items (5% of the Balance in Account 254 at end of period, or amounts less than $50,000 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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	STATEMENT OF FINANCIAL ACCOUNTING	33,811,402		1,247,455	823,019	33,386,966
2	STANDARDS NO. 109: ACCOUNTING FOR					
3	INCOME TAXES					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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35						
36						
37						
38						
39						
41	TOTAL	33,811,402		1,247,455	823,019	33,386,966

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

ACCOUNTS CHARGED 182.3, 190, 282 & 283

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

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	97,756,330	90,931,234
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	80,642,414	77,997,096
5	Large (or Ind.) (See Instr. 4)	40,605,386	38,955,177
6	(444) Public Street and Highway Lighting	1,497,284	1,490,800
7	(445) Other Sales to Public Authorities	17,446,942	16,685,591
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	143,642	90,393
10	TOTAL Sales to Ultimate Consumers	238,091,998	226,150,291
11	(447) Sales for Resale		
12	TOTAL Sales of Electricity	238,091,998	226,150,291
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	238,091,998	226,150,291
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	212,086	203,078
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	-276,633	687,600
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	278,206	170,842
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	213,659	1,061,520
27	TOTAL Electric Operating Revenues	238,305,657	227,211,811

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Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

ELECTRIC OPERATING REVENUES (Account 400)

5. 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 footnote.)
See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. 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
1,478,082	1,382,100	116,500	115,217	2
				3
1,372,435	1,335,909	12,878	12,755	4
785,489	771,380	396	395	5
18,776	18,742	281	274	6
310,899	302,580	973	961	7
				8
2,551	1,644			9
3,968,232	3,812,355	131,028	129,602	10
				11
3,968,232	3,812,355	131,028	129,602	12
				13
3,968,232	3,812,355	131,028	129,602	14

Line 12, column (b) includes $	-247,000	of unbilled revenues.
Line 12, column (d) includes	-3,998	MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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 OR					
2	DOMESTIC SALES					
3						
4	RESIDENTIAL SERVICE					
5	SHEET 30 (1)	1,480,036	97,892,235	116,500	12,704	0.0661
6	SHEET 32 (2)					
7	SHEET 40 (3)					
8	SHEET 41 (4)					
9						
10	OUTDOOR LIGHTING SERVICE					
11	SHEET 65 (5)	969	119,860			0.1237
12	SHEET 67 (6)	105	17,235			0.1641
13						
14	UNBILLED REVENUE	-3,028	-273,000			0.0902
15						
16	TOTAL (440) RESIDENTIAL	1,478,082	97,756,330	116,500	12,687	0.0661
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	TOTAL Billed	3,972,230	238,338,998	131,028	30,316	0.0600
42	Total Unbilled Rev.(See Instr. 6)	-3,998	-247,000	0	0	0.0618
43	TOTAL	3,968,232	238,091,998	131,028	30,285	0.0600

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	COMMERCIAL AND INDUSTRIAL					
2						
3	RESIDENTIAL SERVICE					
4	SHEET 30 (7)	14,952	1,005,889	1,799	8,311	0.0673
5						
6	DISTRIBUTION SERVICE					
7	SHEET 40 (8)	875,609	55,679,048	10,906	80,287	0.0636
8	SHEET 42 (9)	6,485	320,895	98	66,173	0.0495
9	SHEET 43 (10)	10	906	1	10,000	0.0906
10	SHEET 44 (11)	5,958	387,562	103	57,845	0.0650
11						
12	PRIMARY SERVICE					
13	SHEET 45 (12)	25,445	1,344,024	7	3,635,000	0.0528
14						
5	TIME OF DAY DISTRIBUTION					
16	SERVICES					
17	SHEET 41 (13)	1,051,659	52,858,269	192	5,477,391	0.0503
18						
19	TIME OF DAY TRANSMISSION					
20	SERVICE					
21	SHEET 51 (14)	142,390	7,167,210	5	28,478,000	0.0503
22						
23	OUTDOOR LIGHTING SERVICE					
24	SHEET 65(15)	3,524	330,844			0.0939
25	SHEET 67 (16)	156	25,206			0.1616
26						
27	TRAFFIC LIGHTING SERVICE					
28	SHEET 61 (17)	1	10	1	1,000	0.0100
29						
30	STREET LIGHTING SERVICE					
31	SHEET 60 (18)	96	28,939	30	3,200	0.3014
32	SHEET 69 (19)	179	21,376	23	7,783	0.1194
33						
34						
35						
36						
37						
38						
9						
40						
41	TOTAL Billed	3,972,230	238,338,998	131,028	30,316	0.0600
42	Total Unbilled Rev.(See Instr. 6)	-3,998	-247,000	0	0	0.0618
43	TOTAL	3,968,232	238,091,998	131,028	30,285	0.0600

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3	SPECIAL CONTRACTS					
4	METERED (20)					
5	UNMETERED (21)					
6						
7	LOAD MANAGEMENT RIDERS					
8	SHEET 73(22)	32,514	2,137,942	109	298,294	0.0658
9	SHEET 74 (23)		-58,320			
10						
11	UNBILLED REVENUE	-1,054	-2,000			0.0019
12						
13	TOTAL (442) COMMERCIAL	2,157,924	121,247,800	13,274	162,568	0.0562
14						
15						
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35						
36						
37						
38						
39						
40						
41	TOTAL Billed	3,972,230	238,338,998	131,028	30,316	0.0600
42	Total Unbilled Rev.(See Instr. 6)	-3,998	-247,000	0	0	0.0618
43	TOTAL	3,968,232	238,091,998	131,028	30,285	0.0600

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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) PUBLIC STREET AND					
2	HIGHWAY LIGHTING					
3						
4	DISTRIBUTION SERVICE					
5	SHEET 40 (24)	1,322	87,474	15	88,133	0.0662
6						
7	STREET LIGHTING SERVICE					
8	SHEET 60(25)	11,497	1,114,164	165	69,679	0.0969
9	SHEET 66(26)	415	53,941			0.1300
10	SHEET 68 (27)					
11	SHEET 69(28)					
12						
13	TRAFFIC LIGHTING SERVICE					
14	SHEET 61 (29)	5,542	241,705	101	54,871	0.0436
15						
16	UNBILLED REVENUE					
17						
18	TOTAL (444) PUBLIC STREET	18,776	1,497,284	281	66,819	0.0797
19						
20						
21						
22						
23						
24						
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26						
27						
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29						
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36						
37						
38						
39						
40						
41	TOTAL Billed	3,972,230	238,338,998	131,028	30,316	0.0600
42	Total Unbilled Rev.(See Instr. 6)	-3,998	-247,000	0	0	0.0618
43	TOTAL	3,968,232	238,091,998	131,028	30,285	0.0600

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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	(445) SALES TO OTHER PUBLIC					
2	AUTHORITIES					
3						
4	RESIDENTIAL SERVICE					
5	SHEET 30 (30)	18	1,216	2	9,000	0.0676
6						
7	DISTRIBUTION SERVICE					
8	SHEET 40(31)	112,215	7,323,443	829	135,362	0.0653
9	SHEET 42(32)	7,450	363,783	19	392,105	0.0488
10	SHEET 43 (33)	413	35,934	26	15,885	0.0870
11	SHEET 44 (34)	190	13,365	42	4,524	0.0703
12						
13	PRIMARY SERVICE					
14	SHEET 45 (35)	8,770	464,727	5	1,754,000	0.0530
15						
16	TIME OF DAY DISTRIBUTION					
17	SERVICE					
18	SHEET 41 (36)	134,252	7,032,532	28	4,794,714	0.0524
19						
20	TIME OF DAY TRANSMISSION					
21	SERVICE					
22	SHEET 51 (37)	42,781	1,856,879	4	10,695,250	0.0434
23						
24	OUTDOOR LIGHTING SERVICE					
25	SHEET 65 (38)	729	66,179			0.0908
26	SHEET 67 (39)	46	4,668			0.1015
27						
28	SPECIAL CONTRACTS					
29	METERED (40)					
30						
31	LOAD MANAGEMENT RIDERS					
32	SHEET 73 (41)	3,626	241,743	7	518,000	0.0667
33	SHEET 74 (42)					
34	SHEET 61 (43)	325	14,473	11	29,545	0.0445
35						
36	UNBILLED REVENUE	84	28,000			0.3333
37						
38	TOTAL (445) SALES TO OTHER	310,899	17,446,942	973	319,526	0.0561
39	PUBLIC AUTHORITIES					
40						
41	TOTAL Billed	3,972,230	238,338,998	131,028	30,316	0.0600
42	Total Unbilled Rev.(See Instr. 6)	-3,998	-247,000	0	0	0.0618
43	TOTAL	3,968,232	238,091,998	131,028	30,285	0.0600

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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	(448) INTERDEPARTMENTAL	2,551	143,642			0.0563
2	SALES (44)					
3						
4	TOTAL (448) INTER-DEPART	2,551	143,642			0.0563
5						
6						
7						
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10						
11						
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35						
36						
37						
38						
39						
40						
41	TOTAL Billed	3,972,230	238,338,998	131,028	30,316	0.0600
42	Total Unbilled Rev.(See Instr. 6)	-3,998	-247,000	0	0	0.0618
43	TOTAL	3,968,232	238,091,998	131,028	30,285	0.0600

Schedule Page: 304 Line No.: 5 Column: c

ALL FOOTNOTE REFERNCES REPRESENT THE DETAIL OF ADDITIONAL REVENUE NOT INCLUDED IN THE BASE RATES FROM FUEL ADJUSTMENT CLAUSE

-3734693

Schedule Page: 304.1 Line No.: 4 Column: c

-37746

Schedule Page: 304.1 Line No.: 7 Column: c

-2219254

Schedule Page: 304.1 Line No.: 8 Column: c

-16376

Schedule Page: 304.1 Line No.: 9 Column: c

-26

Schedule Page: 304.1 Line No.: 10 Column: c

-15045

Schedule Page: 304.1 Line No.: 13 Column: c

-64178

Schedule Page: 304.1 Line No.: 17 Column: c

-2544265

Schedule Page: 304.1 Line No.: 21 Column: c

-288559

Schedule Page: 304.1 Line No.: 24 Column: c

-8881

Schedule Page: 304.1 Line No.: 25 Column: c

-391

Schedule Page: 304.1 Line No.: 28 Column: c

-1

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-241

Schedule Page: 304.1 Line No.: 32 Column: c

-452

Schedule Page: 304.3 Line No.: 5 Column: c

-3087

Schedule Page: 304.3 Line No.: 8 Column: c

-29033

Schedule Page: 304.3 Line No.: 9 Column: c

-1047

Schedule Page: 304.3 Line No.: 14 Column: c

-15145

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-45

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-281914

Schedule Page: 304.4 Line No.: 9 Column: c

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) X An Original (2) _ A Resubmission	/ /	2005/Q4

FOOTNOTE DATA

-18811

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-1044

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-481

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-21145

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-809314

Schedule Page: 304.4 Line No.: 22 Column: c

-108021

Schedule Page: 304.4 Line No.: 25 Column: c

-1837

Schedule Page: 304.4 Line No.: 26 Column: c

-110

Schedule Page: 304.4 Line No.: 32 Column: c

-6767

Schedule Page: 304.4 Line No.: 34 Column: c

-819

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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	150	
5	(501) Fuel	36	
6	(502) Steam Expenses	132	
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	4,526	
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	4,844	
14	Maintenance		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant	45	
18	(513) Maintenance of Electric Plant	1,985	
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	2,030	
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	6,874	
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)		

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Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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)
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)		
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant	39	
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	39	
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	39	
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	168,157,736	162,497,293
77	(556) System Control and Load Dispatching	3,517	53
78	(557) Other Expenses		
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	168,161,253	162,497,346
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	168,168,166	162,497,346
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	131,418	21,957
84	(561) Load Dispatching	1,050,736	994,168
85	(562) Station Expenses	19,271	4,135
86	(563) Overhead Lines Expenses	16,894	26,720
87	(564) Underground Lines Expenses		
88	(565) Transmission of Electricity by Others	16,253,226	14,583,181
89	(566) Miscellaneous Transmission Expenses	902,535	215,589
90	(567) Rents	924	924
91	TOTAL Operation (Enter Total of lines 83 thru 90)	18,375,004	15,846,674
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	21,567	12,154
94	(569) Maintenance of Structures	8,370	27,342
95	(570) Maintenance of Station Equipment	61,106	74,340
96	(571) Maintenance of Overhead Lines	117,031	71,036
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	1,038	8,318
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	209,112	193,190
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	18,584,116	16,039,864
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	299,139	276,369

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Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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)
104	3. DISTRIBUTION Expenses (Continued)		
105	(581) Load Dispatching	181,072	187,047
106	(582) Station Expenses	31,614	11,006
107	(583) Overhead Line Expenses	287,367	229,396
108	(584) Underground Line Expenses	130,275	131,554
109	(585) Street Lighting and Signal System Expenses	2,339	516
110	(586) Meter Expenses	108,941	70,995
111	(587) Customer Installations Expenses	388,542	322,131
112	(588) Miscellaneous Expenses	215,911	154,914
113	(589) Rents	494,928	494,928
114	TOTAL Operation (Enter Total of lines 103 thru 113)	2,140,128	1,878,856
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	186,749	144,124
117	(591) Maintenance of Structures	25,539	21,036
118	(592) Maintenance of Station Equipment	355,212	173,430
119	(593) Maintenance of Overhead Lines	2,273,444	4,059,524
120	(594) Maintenance of Underground Lines	180,992	224,228
121	(595) Maintenance of Line Transformers	95,896	123,369
122	(596) Maintenance of Street Lighting and Signal Systems	141,150	51,014
123	(597) Maintenance of Meters	164,973	94,514
124	(598) Maintenance of Miscellaneous Distribution Plant	88,760	91,464
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	3,512,715	4,982,703
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	5,652,843	6,861,559
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	44,887	208,472
130	(902) Meter Reading Expenses	986,537	861,922
131	(903) Customer Records and Collection Expenses	2,787,640	2,468,820
132	(904) Uncollectible Accounts	3,312,738	2,304,269
133	(905) Miscellaneous Customer Accounts Expenses	96,072	149,710
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	7,227,874	5,993,193
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision		
138	(908) Customer Assistance Expenses	95,691	96,021
139	(909) Informational and Instructional Expenses	122,174	
140	(910) Miscellaneous Customer Service and Informational Expenses	428,969	268,715
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	646,834	364,736
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision	53,656	123,442
145	(912) Demonstrating and Selling Expenses	5	426
146	(913) Advertising Expenses	18,476	10,338
147	(916) Miscellaneous Sales Expenses	1,718,576	-288,136
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	1,790,713	-153,930
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	2,981,638	2,629,294
152	(921) Office Supplies and Expenses	1,129,623	1,032,411
153	(Less) (922) Administrative Expenses Transferred-Credit	13,147	9,094

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Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	1,018,193	1,061,940
156	(924) Property Insurance	470,171	24,742
157	(925) Injuries and Damages	432,183	291,947
158	(926) Employee Pensions and Benefits	3,124,822	2,372,688
159	(927) Franchise Requirements		
160	(928) Regulatory Commission Expenses	386,177	639,538
161	(929) (Less) Duplicate Charges-Cr.	229,912	95,264
162	(930.1) General Advertising Expenses		
163	(930.2) Miscellaneous General Expenses	362,081	186,386
164	(931) Rents	1,410,436	1,034,197
165	TOTAL Operation (Enter Total of lines 151 thru 164)	11,072,265	9,168,785
166	Maintenance		
167	(935) Maintenance of General Plant	254,432	288,600
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	11,326,697	9,457,385
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	213,397,243	201,060,153

Schedule Page: 320 Line No.: 84 Column: b

$49,037 of account 561 can be further classified into account number 561.BA for Balancing Authority costs, incurred by Control Area Operators as a result of implementing the Markets and Services pursuant to Midwest-ISO's schedule 24.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	ASSOCIATED UTILITIES					
2	LaFarge Gypsum	OS				
3	THE CINCINNATI GAS & ELECTRIC CO	OS	56			
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

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)	
							1
1,029				133,851		133,851	2
4,274,517			60,572,736	103,398,149	4,053,000	168,023,885	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
4,275,546			60,572,736	103,532,000	4,053,000	168,157,736	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	Williamstown			OS
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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 ignations under which service, as identified in column (d), is provided.
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.
5/226				63,332	63,332	1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
			0	63,332	63,332	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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.
		278,206	278,206	1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
0	**0**	**278,206**	**278,206**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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 ˋhorities, qualifying facilities, and others for the quarter.
ın 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)	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	The Cincinnati Gas and	OS	4,274,517			16,253,226		16,253,226
2	Electric Company							
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		4,274,517			16,253,226		16,253,226

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	105,817
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Union Ratification Bonus Accrual	128,000
7	Directors' Fees and Expenses	62,673
8		
9	Materials and Supplies	24,336
10	Advertising	12,771
11	Community Relations	10,119
12	Cinergy Services	8,991
13	Postage	8,208
14	Other	1,166
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
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44		
45		
46	TOTAL	362,081

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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			207,544		207,544
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	666,124				666,124
8	Distribution Plant	8,528,706				8,528,706
9	General Plant	6,154		15,257		21,411
10	Common Plant-Electric	135,602		985,508		1,121,110
11	TOTAL	9,336,586		1,208,309		10,544,895

B. Basis for Amortization Charges

Page 336 does not include depreciation provided for Transportation, Power Operated Equipment, or Trailers as these amounts are charged to a Transportation Clearing Account

The Respondent determines its monthly Provision for Depreciation by the application of rates to the previous month-end balances of property capitalized in each primary plant account plus property in Account 106-Completed Construction not Classified.

In 1997, the Respondent adopted vintage year accounting for General Plant Accounts in accordance with FERC Accounting Research Release No. 15

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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	KPSC Commission Expense				
2	Gas Related	204,187		204,187	
3	Electric Related	373,918		373,918	
4					
5	Federal Energy Regulatory Commission				
6	Docket - N/A Annual Assessment				
7	Pursuant to Federal Energy Regulatory				
8	Commission Order Number 472				
9	Gas Related	-41,392		-41,392	
10	Electric Related	-96,466		-96,466	
11					
12	Midwest Independent System Operator (MISO)				
13	FERC Annual Assessment	81,715		81,715	
14					
15	Kentucky Public Service Commission				
16	Case No. 2001-092				
17	Request for Rate Increase-Gas				7,259
18					
19	AMRP Rate Study Case No. 2001-092				226,950
20					
21	Kentucky Public Service Commission				
22	Case No. 2005-042				
23	Request for Rate Increase-Gas		150,147	150,147	31,321
24					
25	Kentucky Public Service Commission				
26	Case No. 2006-000				
27	Request for Rate Increase-Electric		27,010	27,010	
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	521,962	177,157	699,119	265,530

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
GAS	928	204,187					2
ELECTRIC	928	373,918					3
							4
							5
							6
							7
							8
GAS	928	-41,392					9
ELECTRIC	928	-96,466					10
							11
							12
ELECTRIC	928	81,715					13
							14
							15
							16
GAS	928				7,259		17
							18
	928				32,040	194,910	19
							20
							21
							22
GAS	928	150,147	150,147			181,468	23
							24
							25
							26
ELECTRIC	928	27,010	27,010			27,010	27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		699,119	177,157		39,299	403,388	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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	8,087		
4	Transmission	241,203		
5	Distribution	1,261,145		
6	Customer Accounts	2,561,351		
7	Customer Service and Informational	347,209		
8	Sales	42,578		
9	Administrative and General	2,736,644		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	7,198,217		
11	Maintenance			
12	Production	1,767		
13	Transmission	128,380		
14	Distribution	1,569,438		
15	Administrative and General	154,033		
16	TOTAL Maint. (Total of lines 12 thru 15)	1,853,618		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	9,854		
19	Transmission (Enter Total of lines 4 and 13)	369,583		
20	Distribution (Enter Total of lines 5 and 14)	2,830,583		
21	Customer Accounts (Transcribe from line 6)	2,561,351		
22	Customer Service and Informational (Transcribe from line 7)	347,209		
23	Sales (Transcribe from line 8)	42,578		
24	Administrative and General (Enter Total of lines 9 and 15)	2,890,677		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	9,051,835	776,879	9,828,714
26	Gas			
27	Operation			
28	Production-Manufactured Gas	186,342		
29	Production-Nat. Gas (Including Expl. and Dev.)			
30	Other Gas Supply	216,938		
31	Storage, LNG Terminaling and Processing			
32	Transmission	853		
33	Distribution	2,290,269		
34	Customer Accounts	1,565,309		
35	Customer Service and Informational	331,276		
36	Sales	7,200		
37	Administrative and General	1,862,063		
38	TOTAL Operation (Enter Total of lines 28 thru 37)	6,460,250		
39	Maintenance			
40	Production-Manufactured Gas	51,112		
41	Production-Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution	1,006,130		
46	Administrative and General	65,113		
47	TOTAL Maint. (Enter Total of lines 40 thru 46)	1,122,355		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Total Operation and Maintenance			
49	Production-Manufactured Gas (Enter Total of lines 28 and 40)	237,454		
50	Production-Natural Gas (Including Expl. and Dev.) (Total lines 29,			
51	Other Gas Supply (Enter Total of lines 30 and 42)	216,938		
52	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
53	Transmission (Lines 32 and 44)	853		
54	Distribution (Lines 33 and 45)	3,296,399		
55	Customer Accounts (Line 34)	1,565,309		
56	Customer Service and Informational (Line 35)	331,276		
57	Sales (Line 36)	7,200		
58	Administrative and General (Lines 37 and 46)	1,927,176		
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)	7,582,605	13,871	7,596,476
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	16,634,440	790,750	17,425,190
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	5,641,318	669,625	6,310,943
66	Gas Plant	3,847,457	9,102	3,856,559
67	Other (provide details in footnote):			
68	TOTAL Construction (Total of lines 65 thru 67)	9,488,775	678,727	10,167,502
69	Plant Removal (By Utility Departments)			
70	Electric Plant	393,024	45,199	438,223
71	Gas Plant	138,285	336	138,621
72	Other (provide details in footnote):			
73	TOTAL Plant Removal (Total of lines 70 thru 72)	531,309	45,535	576,844
74	Other Accounts (Specify, provide details in footnote):	487,882		487,882
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95	TOTAL Other Accounts	487,882		487,882
96	TOTAL SALARIES AND WAGES	27,142,406	1,515,012	28,657,418

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) X An Original (2) _ A Resubmission	/ /	2005/Q4

FOOTNOTE DATA

Schedule Page: 354 Line No.: 74 Column: b

Other Accounts:

Merchandising, Jobbing, Contract	90,510
Misc. Deferred Debits	127,705
Miscellaneous	269,667
	487,882

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.

1. COMMON UTILITY PLANT EXPENSE ACCOUNTS ARE NOT MAINTAINED, BUT SUCH EXPENSES ARE ALLOCATED TO GAS AND ELECTRIC DEPARTMENTS PRINCIPALLY ON ONE OR MORE OF THE FOLLOWING BASIS :

FLOOR SPACE UTILIZED FOR BUILDINGS AND OFFICE EQUIPMENT
GENERAL LABOR - TOTAL COMPANY
NUMBER OF GAS AND ELECTRIC CUSTOMERS
IT OPERATIONS

2. PRIOR TO ESTABLISHMENT OF ORIGINAL COST, MESSRS. BRENNER AND EILERS OF THE RESPONDENT AND CAMPBELL AND SCHWARTZ FROM COLUMBIA SYSTEM MET WITH MR. SMITH OF THE FEDERAL POWER COMMISSION TO DISCUSS AMONGST OTHER THINGS, THE FEDERAL POWER COMMISSION'S PERMISSION TO USE THE COMMON UTILITY PLANT ACCOUNTS. IT WAS POINTED OUT BY THE REPRESENTATIVES OF THE RESPONDENT THAT BECAUSE OF THE NATURE OF THE RESPONDENT'S OPERATIONS IT WAS IMPOSSIBLE AND IMPRACTICAL TO ASSIGN CERTAIN TYPES OF EQUIPMENT DIRECTLY TO EITHER GAS OR ELECTRIC UTILITY PLANT. BECAUSE OF THE FACTS PRESENTED, MR. SMITH GAVE THE RESPONDENT'S REPRESENTATIVES VERBAL PERMISSION TO USE THE COMMON PLANT ACCOUNTS.

ACCOUNT TITLE	BALANCE BEGINNING OF YEAR	ADDITIONS	RETIREMENTS	TRANSFERS	BALANCE END OF YEAR
COMMON PLANT IN SERVICE					
Misc Intangible Plant	15,245,626	1,453,750	(160,987)		16,538,389
Land	1,189,864				1,189,864
Structures & Improvements	6,268,227	2,119,990	(67,932)		8,320,285
Office Furniture & Equip	687,158	38,556	(325,947)		397,767
Electronic Data Proc Equip	0				0
Transportation Equipment	0				0
Stores Equipment	5,563				5,563
Tools, Shop & Garage Equip	148,339	40,003	(2,514)		185,828
Communication Equipment	39,252				39,252
Miscellaneous Equipment	0	11,372			11,372
Total Common Plant in Service	23,584,029	3,661,671	(557,380)		26,688,320
Construction Work in Progress	1,514,000	91,558			1,605,558
Total Common Utility Plant	25,098,029	3,753,229	(557,380)		28,293,878

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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.

ALLOCATION OF COMMON PLANT TO UTILITY DEPARTMENTS
Summary by Account Estimated as of 12/31/2005

Gas Department	38.13%	10,788,456
Elec Department	61.87%	17,505,422
	------	-----------
	100.00%	28,293,878

(1) Classification of Account 106, Completed Construction Not Classified, included in the Additions column.

Summary by Account Estimated as of 12/31/2005

Account	Beginning Balance	Amount Included In Additons & Transfers Columns	Ending Balance
Structures & Improvements	53,922	2,062,922	2,116,844
Office Furniture & Equip			
Tools, Shop & Garage Equip	4,465	(4,465)	0
Communication Equipment	39,252		39,252
Miscellaneous Equipment	0	11,372	11,372
	---------	-------------------	---------
Total Account 106 - Common	97,639	2,069,829	2,167,468

(2) The percentages used to allocate Common Plant to utility departments are the weighted average resulting from the application of the individual allocation factors to the investment by various Common Plant accounts as of 12/31/2004. The individual factors are based primarily on general labor and the number of customers at 12/31/2004.

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.

ACCUMULATED PROVISTION FOR DEPRECIATION AND AMORTIZATION OF COMMON UTILITY PLANT

Summary by Account Estimated as of 12/31/2004		9,610,470
Depreciation provision for the year charged to :		
(403) Depreciation expense (1)	254,515	
(404) Amortization - Limited Term Plant	1,754,476	
Transportation expense - clearing	0	
		2,008,991
Net Charges for Plant Retired:		
Book cost of Plant retired	(557,379)	
Cost of Removal	(31,868)	
Salvage (Credit)	(0)	
Adjustments	158,282	
		(430,965)
Balance - End of the Year		11,188,496

ALLOCATION OF ACCUMULATED PROVISION FOR DEPRECIATION TO UTILITY DEPARTMENTS (3)

Gas Department	39.36%	4,403,792
Elec Department	60.64%	6,784,704
Total	100.00%	11,188,496

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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.

METHOD OF DETERMINATION OF DEPRECIATION & AMORTIZATION

Common Plant in Service	Rate
Miscellaneous Intangible Plant	Note (2)
Structures & Improvements	3.97%
Office Furniture & Equipment	Note (4)
Electronic Data Processing Equipment	Note (4)
Stores Equipment	Note (4)
Tools, Shop & Garage Equipment	Note (4)
Communication Equipment	7.20%
Miscellaneous Equipment	Note (4)

(1) The Respondent amortized its monthly provision for depreciaton by the applicaton of rates to the previous month's balance of property capitalized in each primary plant account plus total Account 106 - Completed Construction Not Classified. The rates became effective February 1, 2002, following the approval of the Kentucky Public Service Commission in Case no. 2001-00092.

(2) The Respondent amortized its investment in Miscellaneous Intangible Plant equally over 60 months for certain projects and 120 for other certain projects.

(3) The percentages used to allocate the Common Plant Accumulated Provision for Depreciation balances to Utility Departments are the weighted averages resulting from the application of the allocation factors to the balance of each primary account in the Common Plant Accumulated Provision at 12/31/2004. These factors are the result in averages by primary plant accounts as determined from the allocation of the Common Utility Plant in Service investment at 12/31/2005.

(4) In 1997, the Respondent adopted vintage year accounting for general plant accounts in accordance with FERC Accounting Release No. 15.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year — Usage - Related Billing Determinant: Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year — Usage - Related Billing Determinant: Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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 (f)	Short-Term Firm Point-to-point Reservation (f)	Other Service (f)
1	January									
2	February									
3	March									
4	Total for Quarter									
5	April									
6	May									
7	June									
8	Total for Quarter									
9	July									
10	August									
11	September									
12	Total for Quarter									
13	October									
14	November									
15	December									
16	Total for Quarter									
17	Total for Year to									

Schedule Page: 400 Line No.: 1 Column: b

ULH&P uses The Cincinnati Gas & Electric Company's transmission system. See The Cincinnati Gas & Electric Compan'y FERC Form 1 for further details.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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)	3,968,232
3	Steam		23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	2,963
7	Other		27	Total Energy Losses	303,322
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	4,274,517
9	Net Generation (Enter Total of lines 3 through 8)				
10	Purchases	4,274,517			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	63,332			
17	Delivered	63,332			
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)	4,274,517			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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.
Report on line 2 by month the system's output in Megawatt hours for each month.
, Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

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	319,330		674	18	800
30	February	368,237		600	10	2000
31	March	343,713		695	2	800
32	April	294,456		510	20	1600
33	May	306,081		623	11	1700
34	June	383,398		816	27	1600
35	July	440,448		892	25	1600
36	August	433,008		855	4	1700
37	September	377,607		725	12	1700
38	October	319,895		652	3	1600
39	November	318,349		589	17	2000
'0	December	369,995		717	9	1900
41	TOTAL	4,274,517				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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	69KV TRANSMISSION POOL		69.00	69.00	POLE	101.53	3.04	
2	YORK STATION	YORK STATION	0.04	69.00	POLE			2
3								
4								
5								
6								
7								
8								
9								
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35								
36					TOTAL	101.53	3.04	2

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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)

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.
	908,313	9,478,364	10,386,677	2,101,583	139,636	924	2,242,143	1
954 ACSR								2
								3
								4
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	908,313	9,478,364	10,386,677	2,101,583	139,636	924	2,242,143	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION 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	york station	york station	0.04	wp			
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
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42							
43							
44	TOTAL		0.04				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
954	ACSR		69						1
									2
									3
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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	ALEXANDRIA SOUTH-CAMPBELL CO	UNATTENDED - D	69.00	13.20	
2	AUGUSTINE-COVINGTON, KY	UNATTENDED - D	138.00	13.20	
3	BEAVER-BOONE CO.	UNATTENDED - D	69.00	13.20	
4	BELLEVUE-CAMPBELL CO.	UNATTENDED - D	138.00	13.20	
5	BUFFINGTON-KENTON CO.	UNATTENDED - T&D	138.00	69.00	13.20
6	CLARYVILLE-CAMBELL CO.	UNATTENDED - D	69.00	13.20	
7	COLD SPRING-KENTON CO.	UNATTENDED - D	138.00	13.20	
8	CONSTANCE-KENTON CO.	UNATTENDED - D	138.00	13.20	
9	CRESCENT-KENTON CO.	UNATTENDED - D	138.00	13.20	
10	CRITTENDEN-GRANT CO.	UNATTENDED - D	69.00	13.20	
11	DECOURSEY-KENTON CO.	UNATTENDED - D	69.00	13.20	
12	DIXIE-BOONE CO.	UNATTENDED - D	69.00	13.20	
13	DONALDSON-KENTON CO.	UNATTENDED - D	138.00	13.20	
14	EMPIRE - BOONE CO.	UNATTENDED - D	69.00	13.20	
15	FLORENCE-BOONE CO.	UNATTENDED - D	138.00	13.20	
16	GRANT-GRANT CO.	UNATTENDED - D	69.00	13.20	
17	HANDS-KENTON CO.	UNATTENDED - D	138.00	13.20	
18	HEBRON- BOONE CO.	UNATTENDED - D	138.00	13.20	
19	KENTON-KENTON CO.	UNATTENDED - T&D	138.00	13.20	
20	KY. UNIVERSITY-CAMP. CO.	UNATTENDED - D	138.00	13.20	
21	LIMABURG-BOONE CO.	UNATTENDED - D	69.00	13.20	
22	LONGBRANCH- BOONE CO.	UNATTENDED - D	138.00	13.20	
23	MARSHALL-CAMPBELL CO.	UNATTENDED - D	69.00	13.20	
24	OAKBROOK - BOONE CO	UNATTENDED - D	69.00	13.20	
25	RICHWOOD-BOONE CO.	UNATTENDED - D	69.00	13.20	
26	VILLA-CRESTVIEW HLS., KY.	UNATTENDED - D	69.00	13.20	
27	WHITE TOWER-KENTON CO.	UNATTENDED - D	69.00	13.20	
28	WILDER-WILDER, KY.	UNATTENDED - T&D	138.00	69.00	13.20
29	YORK-NEWPORT, KY.	UNATTENDED - D	138.00	13.20	
30	3 STATIONS UNDER 10 MVA	UNATTENDED - D	69.00	4.30	
31					
32					
33	Summary of Listed Stations Above				
34	(By Function) not including Commonly Owned				
35	Substations				
36					
37	UNATTENDED - T&D				
38	UNATTENDED - D				
39	UNATTENDED - T				
40	ATTENDED - T&D				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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.

Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
72	2					2
21	2					3
45	2					4
328	5					5
32	3					6
33	2					7
45	2					8
45	2					9
21	2					10
11	1					11
42	2					12
45	2					13
25	2					14
67	3					15
21	2					16
45	2					17
22	1					18
165	3					19
22	1					20
31	3					21
22	1					22
11	1					23
22	1					24
32	3					25
45	2					26
11	1					27
134	2					28
22	1					29
18	5					30
						31
						32
						33
						34
						35
						36
627						37
838						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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	ATTENDED - D				
2	ATTENDED - T				
3					
4					
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36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/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.

Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
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