

LOUISVILLE GAS & ELECTRIC CO /KY/

FORM 8-K (Current report filing)

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Address	220 W MAIN ST P O BOX 32030 LOUISVILLE, KY 40232
Telephone	5026272000
CIK	0000060549
SIC Code	4931 - Electric and Other Services Combined
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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): November 12, 2003

Commission Registrant, State of Incorporation, IRS Employer
File Number Address, and Telephone Number Identification No.

2-26720	Louisville Gas and Electric Company (A Kentucky Corporation) 220 West Main Street P.O. Box 32010 Louisville, Ky. 40232 (502) 627-2000	61-0264150
1-3464	Kentucky Utilities Company (A Kentucky and Virginia Corporation) One Quality Street Lexington, Kentucky 40507-1428 (859) 255-2100	61-0247570

This combined Form 8-K is separately filed by Louisville Gas and Electric Company and Kentucky Utilities Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf and each registrant makes no representation as to information relating to the other registrant.

Item 5. Other Events and Regulation FD Disclosure

In the Annual Report for the year ended December 31, 2002 on Form 10-K ("2002 Annual Report") Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") reported revenues and related cost of sales in compliance with required accounting that was in effect at that time. LG&E and KU were required to adopt the net reporting requirements of Emerging Issues Task Force Issue No. 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities ("EITF 02-03") on January 1, 2003. Therefore, to comply with the net reporting requirements of EITF 02-03, LG&E and KU have reclassified revenues and related expenses previously reported in the 2002 Annual Report.

EITF 02-03 rescinded EITF 98-10 and requires that revenue related to derivative instruments classified as trading, including certain energy sales transactions, be reported net of related cost of sales for all periods presented. EITF 02-03 also requires companies to retroactively reclassify previously reported revenues to conform with the new net reporting requirements.

LG&E and KU are filing this Current Report on Form 8-K to present reclassified financial statements and other related information in response to the requirements of EITF 02-03. The reclassified financial statements are set forth in the attached exhibits to this Form 8-K. These exhibits contain information identical to the corresponding items of the 2002 Annual Report, except that the information contained in the exhibits has been updated to the extent necessary to report energy- trading contracts net of related cost of sales in the income statements for all periods presented. Accordingly, information in the corresponding items in the Companies' 2002 Annual Report should be considered in light of the updated information for such items as provided in this Current Report, which reflects the reclassification of financial data as explained above. No attempt has been made in this report to modify or update other disclosures except as required to reflect the effects of the reclassifications described above. These other disclosures are included in our annual, quarterly and current reports and other information filed with the SEC. Neither reported net operating income, net income, common equity, nor cash flows were impacted by the reclassification of revenue upon adoption of EITF 02-03.

The Companies' 2000 consolidated financial statements were audited by Arthur Andersen LLP, independent public accountants, who expressed an unqualified opinion on those financial statements in their report dated January 26, 2001, excluding the revisions described above. Arthur Andersen LLP has ceased operations and, accordingly, LG&E and KU have been unable to obtain their consent to the use of their report. Therefore, 2000 consolidated financial statements, as reclassified, are omitted.

The following are defined terms used in the Exhibits:

Abbreviation or Acronym Definition

Capital Corp.	LG&E Capital Corp.
Clean Air Act	The Clean Air Act, as amended in 1990
CCN	Certificate of Public Convenience and Necessity
CT	Combustion Turbines
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEl	Electric Energy, Inc.
EITF	Emerging Issues Task Force Issue
E.ON	E.ON AG
EPA	U.S. Environmental Protection Agency
ESM	Earnings Sharing Mechanism
F	Fahrenheit
FAC	Fuel Adjustment Clause
FERC	Federal Energy Regulatory Commission

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FPA	Federal Power Act
FT and FT-A	Firm Transportation
GSC	Gas Supply Clause
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
KU Energy	KU Energy Corporation
KU R	KU Receivables LLC
kV	Kilovolts
Kva	Kilovolt-ampere
KW	Kilowatts
Kwh	Kilowatt hours
LEM	LG&E Energy Marketing Inc.
LG&E	Louisville Gas and Electric Company
LG&E Energy	LG&E Energy Corp.
LG&E R	LG&E Receivables LLC
LG&E Services	LG&E Energy Services Inc.
Mcf	Thousand Cubic Feet
MGP	Manufactured Gas Plant
MISO	Midwest Independent System Operator
Mmbtu	Million British thermal units
Moody's	Moody's Investor Services, Inc.
Mw	Megawatts
Mwh	Megawatt hours
NNS	No-Notice Service
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen Oxide
OATT	Open Access Transmission Tariff
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PBR	Performance-Based Ratemaking
PJM	Pennsylvania, New Jersey, Maryland Interconnection
Powergen	Powergen Limited (formerly Powergen plc)
PUHCA	Public Utility Holding Company Act of 1935
ROE	Return on Equity
RTO	Regional Transmission Organization
S&P	Standard & Poor's Rating Services
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SERP	Supplemental Employee Retirement Plan
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SMD	Standard Market Design
SO2	Sulfur Dioxide
Tennessee Gas	Tennessee Gas Pipeline Company
Texas Gas	Texas Gas Transmission Corporation
TRA	Tennessee Regulatory Authority
Trimble County	LG&E's Trimble County Unit 1
USWA	United Steelworkers of America

Utility Operations Operations of LG&E and KU
VDT Value Delivery Team Process
Virginia Commission Virginia State Corporation Commission
Virginia Staff Virginia State Corporation Commission Staff

Item 7. Financial Statements and Exhibits

- (a) None
- (b) None
- (c) Exhibits

- 99(a) Form 10-K Item 1. Business
- 99(b) Form 10-K Item 6. Selected Financial Data
- 99(c) Form 10-K Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
- 99(d) Form 10-K Item 8. Financial Statements and Supplementary Data

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Louisville Gas and Electric Company

Dated: November 12, 2003

*By: /s/ S. Bradford Rives
Chief Financial Officer*

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Kentucky Utilities Company

Dated: November 12, 2003

*By: /s/ S. Bradford Rives
Chief Financial Officer*

Exhibit Index to Current Report on Form 8-K
Dated November 12, 2003

Exhibit
Number

- 99(a) Form 10-K Item 1. Business
- 99(b) Form 10-K Item 6. Selected Financial Data
- 99(c) Form 10-K Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
- 99(d) Form 10-K Item 8. Financial Statements and Data

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Exhibit 99(a)

LG&E and KU are filing this Current Report on Form 8-K to present reclassified financial statements and other related information in response to the requirements of EITF 02-03. The reclassified financial statements are set forth in the other attached exhibits to this Form 8-K. The information set forth below from Item 1 from the 2002 Annual Report has been included because certain information presented therein was affected by the reclassifications. This exhibit, and the other exhibits to the Form 8-K, contain information identical to the corresponding items of the 2002 Annual Report, except that the information contained in the exhibits has been updated to the extent necessary to report revenues from energy- trading contracts net of related cost of sales for all activities that are trading and involved derivative instruments as defined by Financial Accounting Standards Board Statement No. 133, Accounting for Derivative Instruments and Hedging Activities and to conform the

related disclosures for all periods presented. No attempt has been made in this report to modify or update other disclosures except as required to reflect the effects of the reclassifications described above. These other disclosures are included in our annual, quarterly and current reports and other information filed with the SEC. Neither reported net operating income, net income, common equity, nor cash flows were impacted by the reclassification of revenue upon adoption of EITF 02-03.

ITEM 1. Business.

LG&E and KU are each subsidiaries of LG&E Energy. On December 11, 2000, LG&E Energy was acquired by Powergen plc, now known as Powergen Limited, for cash of approximately \$3.2 billion or \$24.85 per share and the assumption of all of LG&E Energy's debt. As a result of the acquisition, among other things, LG&E Energy became a wholly owned subsidiary of Powergen and, as a result, LG&E and KU became indirect subsidiaries of Powergen. The utility operations (LG&E and KU) of LG&E Energy have continued their separate identities and continue to serve customers in Kentucky, Virginia and Tennessee under their existing names. The preferred stock and debt securities of the utility operations were not affected by this transaction resulting in the utility operations' obligations to continue to file SEC reports. Following the acquisition, Powergen became a registered holding company under PUHCA, and LG&E and KU, as subsidiaries of a registered holding company, became subject to additional regulation under PUHCA.

As a result of the Powergen acquisition and in order to comply with PUHCA, LG&E Services was formed as a subsidiary of LG&E Energy effective on January 1, 2001. LG&E Services provides certain services to affiliated entities, including LG&E and KU, at cost as required under PUHCA. On January 1, 2001, approximately 1,000 employees, mainly from LG&E Energy, LG&E and KU, were moved to LG&E Services.

On July 1, 2002, E.ON, a German company, completed its acquisition of Powergen following receipt of all necessary regulatory approvals. E.ON had announced its pre-conditional cash offer of 5.1 billion pounds sterling (\$7.3 billion) for Powergen on April 9, 2001.

LOUISVILLE GAS AND ELECTRIC COMPANY

General

Incorporated in 1913 in Kentucky, LG&E is a regulated public utility that supplies natural gas to approximately 310,000 customers and electricity to approximately 382,000 customers in Louisville and adjacent areas in Kentucky. LG&E's service area covers approximately 700 square miles in 17 counties and has an estimated population of one million. Included in this area is the Fort Knox Military Reservation, to which LG&E transports gas and provides electric service, but which maintains its own distribution

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systems. LG&E also provides gas service in limited additional areas. LG&E's coal-fired electric generating plants, all equipped with systems to reduce sulfur dioxide emissions, produce most of LG&E's electricity. The remainder is generated by a hydroelectric power plant and combustion turbines. Underground natural gas storage fields help LG&E provide economical and reliable gas service to customers. See Item 2, Properties. LG&E has one wholly owned consolidated subsidiary, LG&E R. LG&E R is a special purpose entity formed in September 2000 to enter into accounts receivable securitization transactions with LG&E. LG&E R started operations in 2001. LG&E is considering unwinding its accounts receivable securitization arrangements involving LG&E R during 2003.

For the year ended December 31, 2002, 73% of total operating revenues were derived from electric operations and 27% from gas operations. Electric and gas operating revenues and the percentages by class of service on a combined basis for this period were as follows:

	(Thousands of \$)			% Combined
	Electric	Gas	Combined	
Residential	\$232,285	\$160,733	\$ 393,018	47%
Commercial	185,112	61,036	246,148	30%
Industrial	111,871	10,232	122,103	15%
Public authorities	57,703	11,197	68,900	8%
Total retail	586,971	243,198	830,169	100%
Wholesale sales	120,553	16,384	136,937	
Gas transported - net	-	6,232	6,232	
Provision for rate collections	12,267	-	12,267	
Miscellaneous	16,251	1,879	18,130	
Total	\$736,042	\$267,693	\$1,003,735	

See Note 13 of LG&E's Notes to Financial Statements under Item 8 for financial information concerning segments of business for the three years ended December 31, 2002.

Electric Operations

The sources of LG&E's electric operating revenues and the volumes of sales for the three years ended December 31, 2002, were as follows:

	2002	2001	2000
ELECTRIC OPERATING REVENUES			
(Thousands of \$)			
Residential	\$232,285	\$205,926	\$205,105
Commercial	185,112	171,540	171,414
Industrial	111,871	104,438	104,738
Public authorities	57,703	53,725	54,270
Total retail	586,971	535,629	535,527
Wholesale sales	120,553	127,253	113,337
Provision for rate			
collections (refunds)	12,267	(720)	(2,500)
Miscellaneous	16,251	11,610	12,851
Total	\$736,042	\$673,772	\$659,215

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ELECTRIC SALES (Thousands of Mwh):

Residential	4,036	3,782	3,722
Commercial	3,493	3,395	3,350
Industrial	3,028	2,976	3,043
Public authorities	1,253	1,224	1,214
Total retail	11,810	11,377	11,329
Wholesale sales	6,387	5,989	5,343
Total	18,197	17,366	16,672

LG&E uses efficient coal-fired boilers, fully equipped with sulfur dioxide removal systems, to generate most of its electricity. LG&E's weighted- average system-wide emission rate for sulfur dioxide in 2002 was approximately 0.55 lbs./Mmbtu of heat input, with every generating unit below its emission limit established by the Kentucky Division for Air Quality.

LG&E set a record local peak load of 2,623 Mw on Monday, August 5, 2002, when the peak daily temperature was 100 degrees F.

The electric utility business is affected by seasonal weather patterns. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year. See LG&E's Results of Operations under Item 7.

LG&E currently maintains a 13 - 15% reserve margin range. At December 31, 2002, LG&E owned steam and combustion turbine generating facilities with a net summer capability of 2,882 Mw and an 80 Mw nameplate rated hydroelectric facility on the Ohio River with a summer capability rate of 48 Mw. At December 31, 2002, LG&E's system net summer capability, including purchases from others and excluding the hydroelectric facility, was 3,037 Mw. See Item 2, Properties.

LG&E and 11 other electric utilities are participating owners of OVEC located in Piketon, Ohio. OVEC owns and operates two power plants that burn coal to generate electricity, Kyger Creek Station in Ohio and Clifty Creek Station in Indiana. LG&E's share is 7%, representing approximately 155 Mw's of generation capacity. LG&E also has agreements with a number of entities throughout the United States for the purchase and/or sale of capacity and energy and for the utilization of their bulk transmission system.

On February 1, 2002, LG&E (along with KU) turned over operational control of its high voltage transmission facilities (100kV and above) to MISO. LG&E (along with KU) is a founding member of MISO. Such membership was obtained in 1998 in response to and consistent with federal policy initiatives. MISO operates a single OATT over the facilities under its control. Currently MISO controls over 100,000 miles of transmission over 1.1 million square miles located in the northern Midwest between Manitoba, Canada and Kentucky. On September 18, 2002, FERC granted a 12.88% ROE on transmission facilities for LG&E, KU and the rest of the MISO owners. This ROE includes a 50 basis point increase because of operational independence.

MISO plans to implement a Congestion Management System in December 2003, in compliance with FERC Order 2000. This system will be similar to the Locational Marginal Pricing (LMP) system currently used by the PJM RTO and contemplated in FERC's SMD NOPR, currently being discussed. MISO filed with FERC a mechanism for recovery of costs for the Congestion Management System, designated Schedule 16 and Schedule 17. The MISO transmission owners, including LG&E and KU, and others have objected to the allocation of costs between market participants and retail native load. This case is currently in a hearing at FERC.

In October 2001, the FERC issued an order requiring that the bundled retail load and grandfathered wholesale load of each member transmission owner (including LG&E) be included in the current calculation of MISO's "cost- adder," a charge designed to recover MISO's costs of operation, including

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start-up capital (debt) costs. LG&E, along with several other transmission owners, opposed the FERC's ruling in this regard, which opposition the FERC rejected in an order on rehearing issued in 2002. Later that year, MISO's transmission owners, including LG&E, appealed the FERC's decision to the United States Court of Appeals for the District of Columbia Circuit. In response, by petition filed November 25, 2002,

the FERC requested that the Court issue a partial remand of its challenged orders to allow the FERC to revisit certain issues raised therein, and further requested that the case be held in abeyance pending the agency's resolution of such issues. The Court granted the FERC's petition by order dated December 6, 2002. On February 24, 2003, FERC issued an order reaffirming its position concerning the calculation of the "cost-adder".

As a separate matter, MISO, its transmission owners and other interested industry segments reached a settlement in mid-2002 regarding the level of cost responsibility properly borne by bundled and grandfathered load under these FERC rulings (such settlement expressly not prejudicing the transmission owners' and LG&E's right to challenge the FERC's ruling imposing cost responsibility on bundled loads in the first instance). On February 24, 2003, FERC accepted a partial settlement between MISO and the transmission owners. FERC did not accept the only contested section of the settlement, which would have allowed the transmission owners to immediately treat unrecoverable Schedule 10 charges as regulatory assets. FERC will consider allowing regulatory asset treatment of unrecoverable Schedule 10 charges on a case-by-case basis.

Gas Operations

The sources of LG&E's gas operating revenues and the volumes of sales for the three years ended December 31, 2002, were as follows:

	2002	2001	2000
GAS OPERATING REVENUES			
(Thousands of \$)			
Residential	\$160,733	\$177,387	\$159,670
Commercial	61,036	70,296	61,888
Industrial	10,232	15,750	15,898
Public authorities	11,197	13,223	9,193
Total retail	243,198	276,656	246,649
Wholesale sales	16,384	5,702	17,344
Gas transported - net	6,232	6,042	6,922
Miscellaneous	1,879	2,375	1,574
Total	\$267,693	\$290,775	\$272,489
GAS SALES (Millions of cu. ft.):			
Residential	22,124	20,429	24,274
Commercial	9,074	8,587	10,132
Industrial	1,783	2,160	3,089
Public authorities	1,747	1,681	1,576
Total retail	34,728	32,857	39,071
Wholesale sales	5,345	1,882	5,115
Gas transported	13,939	13,108	14,729
Total	54,012	47,847	58,915

The gas utility business is affected by seasonal weather patterns. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year. See LG&E's Results of Operations under Item 7.

LG&E has five underground natural gas storage fields that help provide economical and reliable gas service to ultimate consumers. By using gas

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storage facilities, LG&E avoids the costs associated with typically more expensive pipeline transportation capacity to serve peak winter space-heating loads. LG&E stores gas in the summer season for withdrawal in the subsequent winter heating season. Without its storage capacity, LG&E would be forced to buy additional gas and pipeline transportation services when customer demand increases, likely to be when the price for those items are typically at their highest. Currently, LG&E buys competitively priced gas from several large suppliers under contracts of varying duration. LG&E's underground storage facilities, in combination with its purchasing practices, enable it to offer gas sales service at rates lower than state and national averages. At December 31, 2002, LG&E had an inventory balance of gas stored underground of 12.6 million Mcf valued at \$50.3 million.

A number of industrial customers purchase their natural gas requirements directly from alternate suppliers for delivery through LG&E's distribution system. These large industrial customers account for about one-fourth of LG&E's annual throughput.

The all-time maximum day gas sendout of 545,000 Mcf occurred on Sunday, January 20, 1985, when the average temperature for the day was -11 degrees

F. During 2002, maximum day gas sendout was approximately 418,000 Mcf, occurring on February 27, 2002, when the average temperature for the day was 21 degrees F. Supply on that day consisted of approximately 130,000 Mcf from purchases, approximately 221,000 Mcf delivered from underground storage, and approximately 67,000 Mcf transported for industrial customers. For a further discussion, see Gas Supply under Item 1.

Rates and Regulation

Following the purchase of Powergen by E.ON, E.ON became a registered holding company under PUHCA. As a result, E.ON, its utility subsidiaries, including LG&E, and certain of its non-utility subsidiaries are subject to extensive regulation by the SEC under PUHCA with respect to issuances and sales of securities, acquisitions and sales of certain utility properties, and intra-system sales of certain goods and services. In addition, PUHCA generally limits the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company. LG&E believes that it has adequate authority (including financing authority) under existing SEC orders and regulations to conduct its business. LG&E will seek additional authorization when necessary.

No costs associated with the E.ON purchase of Powergen or the Powergen purchase of LG&E Energy nor any effects of purchase accounting have been reflected in the financial statements of LG&E.

The Kentucky Commission has regulatory jurisdiction over the rates and service of LG&E and over the issuance of certain of its securities. The Kentucky Commission has the ability to examine the rates LG&E charges its retail customers at any time. LG&E is a "public utility" as defined in the FPA, and is subject to the jurisdiction of the Department of Energy and FERC with respect to the matters covered in the FPA, including the sale of electric energy at wholesale in interstate commerce.

For a discussion of current regulatory matters, see Rates and Regulation for LG&E under Item 7 and Note 3 of LG&E's Notes to Financial Statements under Item 8.

LG&E's retail electric rates contain a FAC, whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. The Kentucky Commission also requires that electric utilities, including LG&E, file certain documents relating to fuel procurement and the purchase of power and energy from other utilities.

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LG&E's retail electric rates are subject to an ESM. The ESM, initially in place for three years beginning in 2000, sets an upper and lower point for rate of return on equity, whereby if LG&E's rate of return for the calendar year falls within the range of 10.5% to 12.5%, no action is necessary. If earnings are above the upper limit, the excess earnings are shared 40% with ratepayers and 60% with shareholders; if earnings are below the lower limit, the earnings deficiency is recovered 40% from ratepayers and 60% from shareholders. By order of the Kentucky Commission, rate changes prompted by the ESM filing go into effect in April of each year subject to a balancing adjustment in successive periods. LG&E made its second ESM filing on March 1, 2002, for the calendar year 2001 reporting period. LG&E is in the process of refunding \$441,000 to customers for the 2001 reporting period. LG&E estimated that the rate of return will fall below the lower limit, subject to Kentucky Commission approval, for the year ended December 31, 2002. The 2002 financial statements include an accrual to reflect the earnings deficiency of \$12.5 million to be recovered from customers commencing in April 2003.

On November 27, 2002, LG&E filed a revised ESM tariff which proposed continuance of the existing ESM through 2005. The Kentucky Commission issued an Order suspending the ESM tariff one day making the effective date January 2, 2003. In addition, the Kentucky Commission is conducting a management audit to review the ESM plan and reassess its reasonableness in 2003. LG&E and interested parties will have the opportunity to provide recommendations for modification and continuance of the ESM or other forms of alternative or incentive regulation.

LG&E's retail rates contain an ECR surcharge which recovers certain costs incurred by LG&E that are required to comply with the Clean Air Act and other environmental regulations. See Note 3 of LG&E's Notes to Financial Statements under Item 8.

LG&E's gas rates contain a GSC, whereby increases or decreases in the cost of gas supply are reflected in LG&E's rates, subject to approval by the Kentucky Commission. The GSC procedure prescribed by order of the Kentucky Commission provides for quarterly rate adjustments to reflect the expected cost of gas supply in that quarter. In addition, the GSC contains a mechanism whereby any over- or under-recoveries of gas supply cost from prior quarters will be refunded to or recovered from customers through the adjustment factor determined for subsequent quarters.

Integrated resource planning regulations in Kentucky require LG&E and the other major utilities to make triennial filings with the Kentucky Commission of various historical and forecasted information relating to load, capacity margins and demand-side management techniques. LG&E filed its most recent integrated resource plan on October 1, 2002.

Pursuant to Kentucky law, the Kentucky Commission has established the boundaries of the service territory or area of each retail electric supplier in Kentucky (including LG&E), other than municipal corporations. Within this service territory each such supplier has the exclusive right to render retail electric service.

Construction Program and Financing

LG&E's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric and gas needs of its service area. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules.

LG&E's estimates of its construction expenditures can vary substantially due to numerous items beyond LG&E's control, such as changes in rates, economic conditions, construction costs, and new environmental or other governmental laws and regulations.

During the five years ended December 31, 2002, gross property additions amounted to approximately \$950 million. Internally generated funds and external financings for the five-year period were utilized to provide for these gross additions. The gross additions during this period amounted to approximately 26% of total utility plant at December 31, 2002, and consisted of \$798 million for electric properties and \$152 million for gas properties. Gross retirements during the same period were \$106 million, consisting of \$74 million for electric properties and \$32 million for gas properties.

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Coal Supply

Coal-fired generating units provided over 97% of LG&E's net kilowatt-hour generation for 2002. The remaining net generation was provided by a natural gas and oil fueled combustion turbine peaking units and a hydroelectric plant. Coal will be the predominant fuel used by LG&E in the foreseeable future, with natural gas and oil being used for peaking capacity and flame stabilization in coal-fired boilers or in emergencies. LG&E has no nuclear generating units and has no plans to build any in the foreseeable future. LG&E has entered into coal supply agreements with various suppliers for coal deliveries for 2003 and beyond. LG&E normally augments its coal supply agreements with spot market purchases. LG&E has a coal inventory policy which it believes provides adequate protection under most contingencies. LG&E had a coal inventory of approximately 1.5 million tons, or a 74-day supply, on hand at December 31, 2002.

LG&E expects to continue purchasing most of its coal, with sulfur content in the 2%-4.5% range, from western Kentucky, southwest Indiana, and West Virginia for the foreseeable future. This supply is relatively low priced coal, and in combination with its sulfur dioxide removal systems is expected to enable LG&E to continue to provide electric service in compliance with existing environmental laws and regulations.

Coal is delivered to LG&E's Mill Creek plant by rail and barge, Trimble County plant by barge and Cane Run plant by rail.

The historical average delivered costs of coal purchased and the percentage of spot coal purchases were as follows:

	2002	2001	2000
Per ton	\$25.30	\$21.27	\$20.96
Per Mmbtu	\$ 1.11	\$.93	\$.92
Spot purchases as % of all sources	2%	3%	1%

The delivered cost of coal is expected to remain relatively flat during 2003. Slight increases in the cost of coal in multi-year contracts signed for 2002 are expected to be offset by lower prices negotiated in contracts signed for 2003.

Gas Supply

LG&E purchases natural gas supplies from multiple sources under contracts for varying periods of time, while transportation services are purchased from Texas Gas and Tennessee Gas.

On April 28, 2000, Texas Gas filed with FERC in Docket RP00-260 for an increase in its base rates effective June 1, 2000. This filing is part of a rate case Texas Gas was required to file pursuant to the settlement in its last rate case. On May 31, 2000, FERC issued an Order suspending the effectiveness of Texas Gas's proposed rates, subject to refund, until November 1, 2000, and establishing a hearing and settlement procedures. As the result of reaching various FERC-approved settlements, Texas Gas's higher motion rates were not billed after July 31, 2002, and its lower prospective rates went into effect on August 1, 2002. Refunds covering the period from November 1, 2000, through July 31, 2002, were received on September 17, 2002, and are currently being refunded to customers through the GSC. LG&E participates in rate and other proceedings affecting its regulated interstate pipeline services, as appropriate.

LG&E transports on the Texas Gas system under NNS and FT rate schedules. During the winter months, LG&E has 184,900 Mmbtu/day in NNS service and

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18,000 Mmbtu/day (increasing to 36,000 Mmbtu/day effective November 1, 2003) in FT service. LG&E's summer NNS levels are 60,000 Mmbtu/day and its summer FT levels are 54,000 Mmbtu/day. Each of these NNS and FT agreements with Texas Gas are subject to termination by LG&E in equal portions during 2005, 2006, and 2008. LG&E also transports on the Tennessee system under Tennessee's FT-A rate schedule. LG&E's contract levels with Tennessee are 51,000 Mmbtu/day throughout the year. The FT-A agreement with Tennessee, which was subject to termination by LG&E during 2002, has been successfully renegotiated for a minimum additional term of five years at a lower price.

LG&E also has a portfolio of supply arrangements with various suppliers in order to meet its firm sales obligations. These gas supply arrangements include pricing provisions that are market-responsive. These firm gas supplies, in tandem with pipeline transportation services,

provide the reliability and flexibility necessary to serve LG&E's customers.

LG&E owns and operates five underground gas storage fields with a current working gas capacity of about 15.1 million Mcf. Gas is purchased and injected into storage during the summer season and is then withdrawn to supplement pipeline supplies to meet the gas-system load requirements during the winter heating season. See Gas Operations under Item 1.

The estimated maximum deliverability from storage during the early part of the heating season is typically about 373,000 Mcf/day. Deliverability decreases during the latter portion of the heating season as the storage inventory is reduced by seasonal withdrawals.

The average cost per Mcf of natural gas purchased by LG&E was \$4.19 in 2002, \$5.27 in 2001 and \$5.08 in 2000. Although natural gas prices in the unregulated wholesale market increased significantly throughout 2000 and early 2001, these prices decreased dramatically in early 2002 and then began to increase again. These increases in natural gas prices, caused in part by decreased natural gas production, decreased liquidity in the marketplace, increases in the price of oil, and increased reliance on natural gas as a fuel for electric generation were mitigated in part by higher national storage inventory levels, and decreased demand associated with a less robust economy.

Environmental Matters

Protection of the environment is a major priority for LG&E. Federal, state, and local regulatory agencies have issued LG&E permits for various activities subject to air quality, water quality, and waste management laws and regulations. For the five-year period ending with 2002, expenditures for pollution control facilities represented \$253.8 million or 27% of total construction expenditures. LG&E estimates that construction expenditures for the installation of NOx control equipment from 2003 through 2004 will be approximately \$32 million. For a discussion of environmental matters, see Rates and Regulation for LG&E under Item 7 and Note 11 of LG&E's Notes to Financial Statements under Item 8.

Competition

In the last several years, LG&E has taken many steps to prepare for the expected increase in competition in its industry, including a reduction in the number of employees; aggressive cost cutting; write-offs of previously deferred expenses; an increase in focus on commercial, industrial and residential customers; an increase in employee involvement and training; a major realignment and formation of new business units, and continuous modifications of its organizational structure. LG&E will continue to take additional steps to better position itself for competition in the future.

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KENTUCKY UTILITIES COMPANY

General

KU, incorporated in Kentucky in 1912 and incorporated in Virginia in 1991, is a regulated public utility engaged in producing, transmitting and selling electric energy. KU provides electric service to approximately 477,000 customers in over 600 communities and adjacent suburban and rural areas in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and to less than 10 customers in Tennessee. In Virginia, KU operates under the name Old Dominion Power Company. KU operates under appropriate franchises in substantially all of the 160 Kentucky incorporated municipalities served. No franchises are required in unincorporated Kentucky or Virginia communities. The lack of franchises is not expected to have a material adverse effect on KU's operations. KU also sells wholesale electric energy to 12 municipalities.

KU has one wholly owned consolidated subsidiary, KU R. KU R is a special purpose entity formed in September 2000 to enter into accounts receivable securitization transactions with KU. KU R began operations in 2001. KU is considering unwinding its accounts receivable securitization arrangements involving KU R during 2003.

Electric Operations

The sources of KU's electric operating revenues and the volumes of sales for the three years ended December 31, 2002, were as follows:

2002 2001 2000

ELECTRIC OPERATING REVENUES

(Thousands of \$):			
Residential	\$275,869	\$244,004	\$241,783
Commercial	179,157	165,389	161,291
Industrial	163,206	146,968	153,017
Mine power	29,453	28,196	27,089
Public authorities	62,649	58,770	57,979

Total retail	710,334	643,327	641,159
Wholesale sales	117,252	164,430	139,541
Provision for rate collections (refunds)	13,027	(954)	-
Miscellaneous	21,051	13,918	12,709
Total	\$861,664	\$820,721	\$793,409
ELECTRIC SALES (Thousands of Mwh):			
Residential	6,198	5,678	5,714
Commercial	4,161	3,990	3,954
Industrial	4,975	4,716	5,044
Mine power	766	771	767
Public authorities	1,533	1,481	1,495
Total retail	17,633	16,636	16,974
Wholesale sales	4,793	6,634	5,942
Total	22,426	23,270	22,916

KU's weighted-average system-wide emission rate for sulfur dioxide in 2002 was approximately 1.24 lbs./Mmbtu of heat input, with every generating unit below its emission limit established by the Kentucky Division for Air Quality.

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KU set a record local peak load of 3,899 Mw on Monday, August 5, 2002, when the peak daily temperature was 100 degrees F.

The electric utility business is affected by seasonal weather patterns. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year. See KU's Results of Operations under Item 7.

KU currently maintains a 13-15% reserve margin range. At December 31, 2002, KU owned steam and combustion turbine generating facilities with a net summer capability of 4,111 Mw and a hydroelectric facility with a summer capability of 24 Mw. See Item 2, Properties. KU obtains power from other utilities under bulk power purchase and interchange contracts. At December 31, 2002, KU's system net summer capability, including purchases from others and excluding the hydroelectric facility, was 4,630 Mw.

Under a contract expiring in 2020 with OMU, KU has agreed to purchase from OMU the surplus output of the 150-Mw and 250-Mw generating units at OMU's Elmer Smith station. Purchases under the contract are made under a contractual formula which has resulted in costs which were and are expected to be comparable to the cost of other power purchased or generated by KU. Such power equated to approximately 8% of KU's net generation system output during 2002. See Note 11 of KU's Notes to Financial Statements under Item 8.

KU owns 20% of the common stock of EEI, which owns and operates a 1,000-Mw generating station in southern Illinois. KU is entitled to take 20% of the available capacity of the station. Purchases from EEI are made under a contractual formula which has resulted in costs which were and are expected to be comparable to the cost of other power purchased or generated by KU. Such power equated to approximately 9% of KU's net generation system output in 2002. See Note 11 of KU's Notes to Financial Statements under Item 8.

KU and 11 other electric utilities are participating owners of OVEC located in Piketon, Ohio. OVEC owns and operates two power plants that burn coal to generate electricity, Kyger Creek Station in Ohio and Clifty Creek Station in Indiana. KU's share is 2.5%, approximately 55 Mws of generation capacity. KU also has agreements with a number of entities throughout the United States for the purchase and/or sale of capacity and energy and for the utilization of their bulk transmission systems.

On February 1, 2002, KU (along with LG&E) turned over operational control of its high voltage transmission facilities (100kV and above) to MISO. KU (along with LG&E) is a founding member of MISO. Such membership was obtained in 1998 in response to and consistent with federal policy initiatives. MISO operates a single OATT over the facilities under its control. Currently MISO controls over 100,000 miles of transmission over 1.1 million square miles located in the northern Midwest between Manitoba, Canada and Kentucky. On September 18, 2002, FERC granted a 12.88% ROE on transmission facilities for LG&E, KU and the rest of the MISO owners. This ROE includes a 50 basis point increase because of operational independence.

MISO plans to implement a Congestion Management System in December 2003, in compliance with FERC Order 2000. This system will be similar to the Locational Marginal Pricing (LMP) system currently used by the PJM RTO and contemplated in FERC's SMD NOPR currently being discussed. MISO filed with FERC a mechanism for recovery of costs for the Congestion Management System, designated Schedule 16 and Schedule 17. MISO transmission owners, including LG&E and KU, and others have objected to the allocation of costs between market participants and retail native load. This case is currently in a hearing at FERC.

In October 2001, the FERC issued an order requiring that the bundled retail load and grandfathered wholesale load of each member transmission owner (including KU) be included in the current calculation of MISO's "cost-adder," a charge designed to recover MISO's costs of operation, including start-up capital (debt) costs. KU, along with several other transmission

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owners, opposed the FERC's ruling in this regard, which opposition the FERC rejected in an order on rehearing issued in 2002. Later that year,

MISO's transmission owners, including KU, appealed the FERC's decision to the United States Court of Appeals for the District of Columbia Circuit. In response, by petition filed November 25, 2002, FERC requested that the Court issue a partial remand of its challenged orders to allow the FERC to revisit certain issues raised therein, and further requested that the case be held in abeyance pending the agency's resolution of such issues. The Court granted the FERC's petition by order dated December 6, 2002. On February 24, 2003, FERC issued an order reaffirming its position concerning the calculation of the "cost-adder".

As a separate matter, MISO, its transmission owners and other interested industry segments reached a settlement in mid-2002 regarding the level of cost responsibility properly borne by bundled and grandfathered load under these FERC rulings (such settlement expressly not prejudicing the transmission owners' and KU's right to challenge the FERC's ruling imposing cost responsibility on bundled loads in the first instance). On February 24, 2003, FERC accepted a partial settlement between MISO and the transmission owners. FERC did not accept the only contested section of the settlement, which would have allowed the transmission owners to immediately treat unrecoverable Schedule 10 charges as regulatory assets. FERC will consider allowing regulatory asset treatment of unrecoverable Schedule 10 charges on a case-by-case basis.

Rates and Regulation

Following the purchase of Powergen by E.ON, E.ON became a registered holding company under PUHCA. As a result, E.ON, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries are subject to extensive regulation by the SEC under PUHCA with respect to issuances and sales of securities, acquisitions and sales of certain utility properties, and intra-system sales of certain goods and services. In addition, PUHCA generally limits the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company. KU believes that it has adequate authority (including financing authority) under existing SEC orders and regulations to conduct its business. KU will seek additional authorization when necessary.

No costs associated with the E.ON purchase of Powergen or the Powergen purchase of LG&E Energy nor any effects of purchase accounting have been reflected in the financial statements of KU.

The Kentucky Commission and the Virginia Commission have regulatory jurisdiction over KU's retail rates and service, and over the issuance of certain of its securities. By reason of owning and operating a small amount of electric utility property in one county in Tennessee (having a gross book value of approximately \$225,000) from which KU served five customers at December 31, 2002, KU is subject to the jurisdiction of the TRA. FERC has classified KU as a "public utility" as defined in the FPA. FERC has jurisdiction under the FPA over certain of the electric utility facilities and operations, wholesale sale of power and related transactions and accounting practices of KU, and in certain other respects as provided in the FPA.

For a discussion of current regulatory matters, see Rates and Regulation for KU under Item 7 and Note 3 of KU's Notes to the Financial Statements under Item 8.

KU's Kentucky retail electric rates contain a FAC, whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges. The Kentucky Commission also requires that electric utilities, including KU, file certain documents relating to fuel procurement and the purchase of power and energy from other utilities. The FAC mechanism for Virginia customers uses an average fuel cost factor based primarily on projected fuel costs. The fuel cost factor may be adjusted annually for over or under collections of fuel costs from the previous year.

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KU's Kentucky retail electric rates are subject to an ESM. The ESM, initially in place for three years beginning in 2000, sets an upper and lower point for rate of return on equity, whereby if KU's rate of return for the calendar year falls within the range of 10.5% to 12.5%, no action is necessary. If earnings are above the upper limit, the excess earnings are shared 40% with ratepayers and 60% with shareholders; if earnings are below the lower limit, the earnings deficiency is recovered 40% from ratepayers and 60% from shareholders. By order of the Kentucky Commission, rate changes prompted by the ESM filing go into effect in April of each year subject to a balancing adjustment in successive periods. KU made its second ESM filing on March 1, 2002 for the calendar year 2001 reporting period. KU is in the process of refunding \$1 million to customers for the 2001 reporting period. KU estimated that the rate of return will fall below the lower limit for the year ended December 31, 2002. The 2002 financial statements include an accrual to reflect the earnings, subject to Kentucky Commission approval, deficiency of \$13.5 million to be recovered from customers commencing in April 2003.

On November 27, 2002, KU filed a revised ESM tariff which proposed continuance of the existing ESM through 2005. The Kentucky Commission issued an Order suspending the ESM tariff one day making the effective date January 2, 2003. In addition, the Kentucky Commission is conducting a management audit to review the ESM plan and reassess its reasonableness in 2003. KU and interested parties will have the opportunity to provide recommendations for modification and continuance of the ESM or other forms of alternative or incentive regulation.

KU's Kentucky retail rates contain an ECR surcharge which recovers certain costs incurred by KU that are required to comply with the Clean Air Act and other environmental regulations. See Note 3 of KU's Notes to Financial Statements under Item 8.

Integrated resource planning regulations in Kentucky require KU and the other major utilities to make triennial filings with the Kentucky Commission of various historical and forecasted information relating to load, capacity margins and demand-side management techniques. KU filed its most recent integrated resource plan on October 1, 2002.

Pursuant to Kentucky law, the Kentucky Commission has established the boundaries of the service territory or area of each retail electric supplier in Kentucky (including KU), other than municipal corporations. Within this service territory each such supplier has the exclusive right to render retail electric service.

The state of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gives Virginia customers a choice for energy services. The change will be phased in gradually between January 2002 and January 2004. KU filed unbundled rates that became effective January 1, 2002. Rates are capped at current levels through June 2007. The Virginia Commission will continue to require each Virginia utility to make annual filings of either a base rate change or an Annual Informational Filing consisting of a set of standard financial schedules. The Virginia Staff will issue a Staff Report regarding the individual utility's financial performance during the historic 12-month period. The Staff Report can lead to an adjustment in rates, but through June 2007 will be limited to decreases. KU was granted a waiver from the Virginia Commission on October 29, 2002, exempting KU from retail choice through December 31, 2004. KU is also seeking a permanent legislative exemption from the Virginia Electric Utility Restructuring Act. The outcome of this legislative initiative is not expected to be known until mid-2003.

Construction Program and Financing

KU's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. KU's estimates of its construction expenditures can vary substantially due to numerous items beyond KU's control, such as changes in rates, economic conditions, construction costs, and new environmental or other governmental laws and regulations.

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During the five years ended December 31, 2002, gross property additions amounted to approximately \$754 million. Internally generated funds and external financings for the five-year period were utilized to provide for these gross additions. The gross additions during this period amounted to approximately 23% of total utility plant at December 31, 2002. Gross retirements during the same period were \$82 million.

Coal Supply

Coal-fired generating units provided over 97% of KU's net kilowatt-hour generation for 2002. The remaining net generation for 2002 was provided by natural gas and oil fueled combustion turbine peaking units and hydroelectric plants. Coal will be the predominant fuel used by KU in the foreseeable future, with natural gas and oil being used for capacity and flame stabilization in coal-fired boilers or in emergencies. KU has no nuclear generating units and has no plans to build any in the foreseeable future.

KU maintains its fuel inventory at levels estimated to be necessary to avoid operational disruptions at its coal-fired generating units. Reliability of coal deliveries can be affected from time to time by a number of factors, including fluctuations in demand, coal mine labor issues and other supplier or transporter operating difficulties.

KU believes there are adequate reserves available to supply its existing base-load generating units with the quantity and quality of coal required for those units throughout their useful lives. KU intends to meet a portion of its coal requirements with three-year or shorter contracts. As part of this strategy, KU will continue to negotiate replacement contracts as contracts expire. KU does not anticipate any problems negotiating new contracts for future coal needs. The balance of coal requirements will be met through spot purchases. KU had a coal inventory of approximately 1.4 million tons, or a 67-day supply, on hand at December 31, 2002.

KU expects to continue purchasing most of its coal, which has a sulfur content in the 0.7% - 3.5% range, from western and eastern Kentucky, West Virginia, southwest Indiana, Wyoming and Pennsylvania for the foreseeable future.

Coal for Ghent is delivered by barge. Deliveries to the Tyrone and Green River locations are by truck. Delivery to E.W. Brown is by rail.

The historical average delivered cost of coal purchased and the percentage of spot coal purchases were as follows:

	2002	2001	2000
Per ton	\$31.44	\$27.84	\$25.63
Per Mmbtu	\$1.35	\$1.20	\$1.07
Spot purchases as % of all sources	18%	44%	51%

KU's historical average cost of coal purchased is higher than LG&E's due to the lower sulfur content of the coal KU purchases for use at its Ghent plant and higher cost to transport coal to the E.W. Brown plant. The delivered cost of coal is expected to increase during 2003.

Environmental Matters

Protection of the environment is a major priority for KU. Federal, state, and local regulatory agencies have issued KU permits for various activities subject to air quality, water quality, and waste management laws and regulations. For the five-year period ending with 2002, expenditures for

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pollution control facilities represented \$63.5 million or 11% of total construction expenditures. KU estimates that construction expenditures for the installation of NO_x control equipment from 2003 through 2004 will be approximately \$178 million. For a discussion of environmental matters, see Rates and Regulation for KU under Item 7 and Note 11 of KU's Notes to Financial Statements under Item 8.

Competition

In the last several years, KU has taken many steps to prepare for the expected increase in competition in its industry, including a reduction in the number of employees; aggressive cost cutting; an increase in focus on commercial, industrial and residential customers; an increase in employee involvement and training; a major realignment and formation of new business units; and continuous modifications of its organizational structure. KU will continue to take additional steps to better position itself for competition in the future.

EMPLOYEES AND LABOR RELATIONS

LG&E had 891 full-time regular employees and KU had 946 full-time regular employees at December 31, 2002. Of the LG&E total, 628 operating, maintenance, and construction employees were represented by IBEW Local 2100. LG&E and employees represented by IBEW Local 2100 signed a four-year collective bargaining agreement in November 2001. Of the KU total, 162 operating, maintenance, and construction employees were represented by IBEW Local 2100 and USWA Local 9447-01. In August 2001, KU and employees represented by IBEW Local 2100 entered into a two-year collective bargaining agreement. KU and employees represented by USWA Local 9447-01 entered into a three-year collective bargaining agreement effective August 2002 and expiring August 2005.

As a result of the Powergen acquisition and in order to comply with PUHCA, LG&E Services was formed effective on January 1, 2001. LG&E Services provides certain services to affiliated entities, including LG&E and KU, at cost as required under the Holding Company Act. On January 1, 2001, approximately 1,000 employees, mainly from LG&E Energy, LG&E and KU, were moved to LG&E Services.

See Note 3 of LG&E's Notes to Financial Statements and Note 3 of KU's Notes to Financial Statements under Item 8 for workforce separation program in effect for 2001.

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Executive Officers of LG&E and KU at December 31, 2002:

Name	Age	Position	Effective Date of Election to Present Position
Victor A. Staffieri	47	Chairman of the Board, President and Chief Executive Officer	May 1, 2001
Richard Aitken-Davies	53	Chief Financial Officer	January 31, 2001
John R. McCall	59	Executive Vice President, General Counsel and Corporate Secretary	July 1, 1994
S. Bradford Rives	44	Senior Vice President - Finance and Controller	December 11, 2000
Paul W. Thompson	45	Senior Vice President - Energy Services	June 7, 2000
Chris Hermann	55	Senior Vice President - Distribution Operations	December 11, 2000
Wendy C. Welsh	48	Senior Vice President - Information Technology	December 11, 2000
Martyn Gallus	38	Senior Vice President - Energy Marketing	December 11, 2000
A. Roger Smith	49	Senior Vice President Project Engineering	December 11, 2000

David A. Vogel	36	Vice President - Retail Services	December 11, 2000
Daniel K. Arbough	41	Treasurer	December 11, 2000
Bruce D. Hamilton	47	Vice President Independent Power Operations	December 11, 2000
Robert E. Henriques	61	Vice President Regulated Generation	September 30, 2001
Michael S. Beer	44	Vice President-Rates and Regulatory	February 1, 2001
George R. Siemens	53	Vice President-External Affairs	January 11, 2001
Paula H. Pottinger	45	Vice President - Human Resources	June 1, 2002
D. Ralph Bowling	45	Vice President - Power Operations WKE	August 1, 2002
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R. W. Chip Keeling	46	Vice President - Communications	March 18, 2002

The present term of office of each of the above executive officers extends to the meeting of the Board of Directors following the 2003 Annual Meeting of Shareholders.

There are no family relationships between or among executive officers of LG&E and KU. The above tables indicate officers serving as executive officers of both LG&E and KU at December 31, 2002. Each of the above officers serves in the same capacity for LG&E and KU.

Before he was elected to his current positions, Mr. Staffieri was President, Distribution Services Division of LG&E Energy Corp. from December 1995 to May 1997; Chief Financial Officer of LG&E Energy Corp. and LG&E from May 1997 to February 1999, (including Chief Financial Officer of KU from May 1998 to February 1999); President and Chief Operating Officer of LG&E Energy Corp. from March 1999 to April 2001 (including President of LG&E and KU from June 2000 to April 2001); Chairman, President and CEO of LG&E Energy Corp., LG&E and KU from May 2001 to present.

Before he was elected to his current positions, Mr. Aitken-Davies was Group Performance Director at Powergen from April 1998 to March 2000; Director - LG&E Transition Team at Powergen from March 2000 to January 2001.

Mr. McCall has been Executive Vice President, General Counsel and Corporate Secretary of LG&E Energy Corp. and LG&E since July 1994. He became Executive Vice President, General Counsel and Corporate Secretary of KU in May 1998.

Before he was elected to his current positions, Mr. Rives was Vice President - Finance and Controller of LG&E Energy Corp. from March 1996 to February 1999; and Senior Vice President - Finance and Business Development from February 1999 to December 2000.

Before he was elected to his current positions, Mr. Thompson was Vice President - Business Development for LG&E Energy Corp. from July 1994 to September 1996; Vice President, Retail Electric Business for LG&E from September 1996 to June 1998; Group Vice President for LG&E Energy Marketing, Inc. from June 1998 to August 1999; Vice President, Retail Electric Business for LG&E from December 1998 to August 1999; and Senior Vice President - Energy Services for LG&E Energy Corp. from August 1999 to June 2000.

Before he was elected to his current positions, Mr. Hermann was Vice President and General Manager, Wholesale Electric Business of LG&E from January 1993 to June 1997; Vice President, Business Integration of LG&E from June 1997 to May 1998; Vice President, Power Generation and Engineering Services, of LG&E from May 1998 to December 1999; and Vice President Supply Chain and Operating Services from December 1999 to December 2000.

Before she was elected to her current positions, Ms. Welsh was Vice President - Information Services of LG&E from January 1994 to May 1997; Vice President, Administration of LG&E Energy Corp. from May 1997 to February 1998; and Vice President-Information Technology from February 1998 to December 2000.

Before he was elected to his current positions, Mr. Gallus was Director, Trading and Risk Management from January 1996 to September 1996; Director, Product Development from September 1996 to April 1997; Vice President, Structured Products from April 1997 to May 1998; Senior Vice President, Trading, from May 1998 to August 1998 for LG&E Energy Marketing Inc.; and Vice President, Energy Marketing from August 1998 to December 2000 for LG&E Energy Corp.

Before he was elected to his current positions, Mr. Smith was Head of Construction Projects - Powergen from January 1996 to May 1999; Director of Projects - Powergen from May 1999 to December 1999; and Director of Engineering Projects for Powergen International from January 2000 to December 2000.

Before he was elected to his current positions, Mr. Vogel served in management positions within the Distribution organization of LG&E and KU prior to December 2000. In his position prior to his current role he was responsible for statewide outage management and restoration of distribution network.

Before he was elected to his current positions, Mr. Arbough was Manager, Corporate Finance of LG&E Energy Corp., and LG&E from August 1996 to May 1998; and he has held the position of Director, Corporate Finance of LG&E Energy Corp., LG&E and KU from May 1998 to present.

Before he was elected to his current positions, Mr. Hamilton was Venture Manager from May 1992 to December 1995; Senior Venture Manager from December 1995 to September 1997 and Vice President, Asset Management from September 1997 to December 2000.

Before he was elected to his current positions, Mr. Henriques was Senior Venture Manager for LG&E Power Inc. from May 1993 to September 1995, and Vice President-Plant Operations from September 1995 to September 2001.

Before he was elected to his current positions, Mr. Beer was Director, Federal Regulatory Affairs, for Illinois Power Company in Decatur, Illinois, from February of 1997 to January of 1998; Senior Corporate Attorney from February 1998 to February 2000; and Senior Counsel Specialist, Regulatory from February 2000 to February 2001.

Before he was elected to his current positions, Mr. Siemens held the position of Director of External Affairs for LG&E from August 1982 to January 2001.

Before she was elected to her current positions as Vice President-Human Resources, Ms. Pottinger was Manager, Human Resources Development from May 1994 to May 1997; and Director, Human Resources from June 1997 to June 2002.

Before he was elected to his current positions, Mr. Bowling was Plant General Manager at Western Kentucky Energy Corp. from July 1998 to December 2001; and General Manager Black Fossil Operations for Powergen in the United Kingdom from January 2002 to August 2002.

Before he was elected to his current positions, Mr. Keeling was General Manager, Marketing Communications for General Electric Company from January 1998 to January 1999. He joined LG&E Energy Corp. and held the title Manager, Media Relations from January 1999 to February 2000; and Director, Corporate Communications for LG&E Energy from February 2000 to March 2002.

Exhibit 99(b)

LG&E and KU are filing this Current Report on Form 8-K to present reclassified financial statements and other related information in response to the requirements of EITF 02-03. The reclassified financial statements are set forth in the other attached exhibits to this Form 8-K. The information set forth below from Item 6 from the 2002 Annual Report has been included because certain information presented therein was affected by the reclassifications. This exhibit, and the other exhibits to the Form 8-K, contain information identical to the corresponding items of the 2002 Annual Report, except that the information contained in the exhibits has been updated to the extent necessary to report revenues from energy-trading contracts net of related cost of sales for all activities that are trading and involved derivative instruments as defined by Financial Accounting Standards Board Statement No. 133, Accounting for Derivative Instruments and Hedging Activities and to conform the related disclosures for all periods presented. No attempt has been made in this report to modify or update other disclosures except as required to reflect the effects of the reclassifications described above. These other disclosures are included in our annual, quarterly and current reports and other information filed with the SEC. Neither reported net operating income, net income, common equity, nor cash flows were impacted by the reclassification of revenue upon adoption of EITF 02-03.

The 2000, 1999 and 1998 consolidated financial data were derived from financial statements audited by Arthur Andersen LLP, independent public accountants, who expressed an unqualified opinion on those financial statements in their report dated January 26, 2001, before the revisions described in Note 1 to the Notes to Financial Statements filed as Exhibit 99(d). Arthur Andersen LLP has ceased operations. The amounts shown below for such periods, reclassified pursuant to the adoption of EITF 02-03, are unaudited.

ITEM 6. Selected Financial Data.

Years Ended December 31
(Thousands of \$)

2002 2001 2000 1999 1998

LG&E:

Operating revenues:					
Revenues	\$991,468	\$965,267	\$934,204	\$847,879	\$854,556
Provision for rate collections (refunds)	12,267	(720)	(2,500)	(1,735)	(4,500)
Total operating revenues	1,003,735	964,547	931,704	846,144	850,056
Net operating income	117,914	141,773	148,870	140,091	135,523
Net income	88,929	106,781	110,573	106,270	78,120
Net income available for common stock	84,683	102,042	105,363	101,769	73,552
Total assets	2,561,078	2,448,354	2,226,084	2,171,452	2,104,637
Long-term obligations (including amounts due within one year)	\$ 616,904	\$ 616,904	\$ 606,800	\$ 626,800	\$ 626,800

LG&E's Management's Discussion and Analysis of Financial Condition and Results of Operation and LG&E's Notes to Financial Statements should be read in conjunction with the above information.

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Years Ended December 31
(Thousands of \$)

2002 2001 2000 1999

1998
KU:

Operating revenues:					
Revenues	\$ 848,637	\$ 821,675	\$ 793,409	\$ 815,532	\$ 807,786
Provision for rate collections (refunds)	13,027	(954)	-	(5,900)	(21,500)
Total operating revenues	861,664	820,721	793,409	809,632	786,286
Net operating income	108,643	121,370	128,136	136,016	125,388
Net income	93,384	96,414	95,524	106,558	72,764
Net income available for common stock	91,128	94,158	93,268	104,302	70,508

Total assets 1,998,383 1,826,902 1,739,518 1,785,090 1,761,201

Long-term obligations (including amounts due within one year) \$ 500,492 \$ 488,506 \$ 484,830 \$ 546,330 \$ 546,330

KU's Management's Discussion and Analysis of Financial Condition and Results of Operation and KU's Notes to Financial Statements should be read in conjunction with the above information.

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Exhibit 99(c)

LG&E and KU are filing this Current Report on Form 8-K to present reclassified financial statements and other related information in response to the requirements of EITF 02-03. The reclassified financial statements are set forth in the other attached exhibits to this Form 8-K. The information set forth below from Item 7 from the 2002 Annual Report has been included because certain information presented therein was affected by the reclassifications. This exhibit, and the other exhibits to the Form 8-K, contain information identical to the corresponding items of the 2002 Annual Report, except that the information contained in the exhibits has been updated to the extent necessary to report revenues from energy-trading contracts net of related cost of sales for all activities that are trading and involved derivative instruments as defined by

Financial Accounting Standards Board Statement No. 133, Accounting for Derivative Instruments and Hedging Activities and to conform the related disclosures for all periods presented. No attempt has been made in this report to modify or update other disclosures except as required to reflect the effects of the reclassifications described above. These other disclosures are included in our annual, quarterly and current reports and other information filed with the SEC. Neither reported net operating income, net income, common equity, nor cash flows were impacted by the reclassification of revenue upon adoption of EITF 02-03.

ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

LG&E:

GENERAL

The following discussion and analysis by management focuses on those factors that had a material effect on LG&E's financial results of operations and financial condition during 2002, 2001, and 2000 and should be read in connection with the financial statements and notes thereto.

Some of the following discussion may contain forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may materially vary. Factors that could cause actual results to materially differ include; general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; actions by credit rating agencies; and other factors described from time to time in LG&E's reports to the SEC, including Exhibit No. 99.01 to the Annual Report.

MERGERS and ACQUISITIONS

On December 11, 2000, LG&E Energy was acquired by Powergen for cash of approximately \$3.2 billion or \$24.85 per share and the assumption of all of LG&E Energy's debt. As a result of the acquisition, LG&E Energy became a wholly owned subsidiary of Powergen and, as a result, LG&E became an indirect subsidiary of Powergen. LG&E has continued its separate identity and serves customers in Kentucky under its existing name. The preferred stock and debt securities of LG&E were not affected by this transaction and LG&E continues to file SEC reports. Following the acquisition, Powergen became a registered holding company under PUHCA, and LG&E, as a subsidiary of a registered holding company, became subject to additional regulation under PUHCA. See "Rates and Regulation" under Item 1.

On July 1, 2002, E.ON, a German company, completed its acquisition of Powergen plc (now Powergen Limited). As a result, LG&E and KU became indirect subsidiaries of E.ON. E.ON had announced its pre-conditional cash offer of 5.1 billion pounds sterling (\$7.3 billion) for Powergen on April 9, 2001. Following the acquisition, E.ON became a registered holding company under PUHCA.

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As contemplated in their regulatory filings in connection with the E.ON acquisition, E.ON, Powergen and LG&E Energy completed an administrative reorganization to move the LG&E Energy group from an indirect Powergen subsidiary to an indirect E.ON subsidiary. This reorganization was effective in March 2003.

RESULTS OF OPERATIONS

Net Income

LG&E's net income in 2002 decreased \$17.9 million as compared to 2001. The decrease resulted primarily from higher transmission operating expenses, an increase in amortization of VDT regulatory asset, and increased property insurance and pension expense, partially offset by an increase in electric sales to retail customers and lower interest expenses.

LG&E's net income decreased \$3.8 million for 2001, as compared to 2000. This decrease is mainly due to higher pension related expenses and amortization of VDT regulatory asset, partially offset by increased electric and gas net revenues (operating revenues less fuel for electric generation, power purchased and gas supply expenses) and decreased interest expenses.

Revenues

A comparison of operating revenues for the years 2002 and 2001, excluding the provisions recorded for rate collections (refunds), with the immediately preceding year reflects both increases and decreases, which have been segregated by the following principal causes (in thousands of \$):

Cause	Increase (Decrease) From Prior Period			
	Electric Revenues		Gas Revenues	
	2002	2001	2002	2001

Retail sales:				
Fuel and gas supply adjustments	\$ 19,449	\$ (394)	\$(58,003)	\$ 79,627
LG&E/KU Merger surcredit	(2,825)	(2,456)	-	-
Performance based rate	-	1,962	-	-
Environmental cost				
recovery surcharge	9,694	1,246	-	-
Demand side management	1,381	-	938	-
Electric rate reduction	-	(3,671)	-	-
VDT surcredit	(1,177)	(1,014)	(285)	(68)
Gas rate increase	-	-	-	15,265
Weather normalization	-	-	2,234	-
Variation in sales volumes				
and other	24,819	4,429	21,658	(64,817)
Total retail sales	51,341	102	(33,458)	30,007
Wholesale sales	(6,700)	13,916	10,683	(11,642)
Gas transportation-net	-	-	189	(880)
Other	4,642	(1,241)	(496)	801
Total	\$ 49,283	\$ 12,777	\$(23,082)	\$ 18,286

Electric revenues increased in 2002 primarily due to an increase in retail sales due to warmer summer weather, an increase in the recovery of fuel costs passed through the FAC, partially offset by a decrease in wholesale sales due to lower market prices as compared to 2001. Cooling degree days

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increased 20% compared to 2001. Electric revenues increased in 2001 primarily due to an increase in wholesale sales and retail sales volume, partially offset by the effects of an electric rate reduction ordered by the Kentucky Commission, and the LG&E/KU merger surcredit (See Note 2 of LG&E's Notes to Financial Statements under Item 8). In January 2000, the Kentucky Commission ordered an electric rate reduction and the termination of LG&E's proposed electric PBR mechanism.

Gas revenues in 2002 decreased due to a lower gas supply cost billed to customers through the gas supply clause offset partially by increased gas retail sales due to cooler winter weather and an increase in wholesale sales volume. Heating degree days increased 17% as compared to 2001. Gas revenues in 2001 increased primarily as a result of higher gas supply costs billed to customers through the gas supply clause and the effects of a gas rate increase ordered by the Kentucky Commission in September 2000. The gas revenue increase was partially offset by a decrease in retail and wholesale gas sales in 2001 due to warmer weather. Heating degree days decreased 10.2% compared to 2000.

Expenses

Fuel for electric generation and gas supply expenses comprise a large component of LG&E's total operating costs. The retail electric rates contain a FAC and gas rates contain a GSC, whereby increases or decreases in the cost of fuel and gas supply are reflected in the FAC and GSC factors, subject to approval by the Kentucky Commission, and passed through to LG&E's retail customers.

Fuel for electric generation increased \$35.7 million (22.4%) in 2002 due to increased generation (\$5.4 million) and higher cost of coal burned (\$30.3 million). Fuel for electric generation decreased \$0.2 million (.1%) in 2001 primarily due to decreased generation as a result of decreased electric sales (\$2.2 million) partially offset by a higher cost of coal burned (\$2.0 million). The average delivered cost per ton of coal purchased was \$25.30 in 2002, \$21.27 in 2001 and \$20.96 in 2000.

Power purchased expense increased \$12.6 million (25.5%) in 2002 due to an increase in purchases to meet requirements for native load partially offset by a decrease in purchase price. Power purchased increased \$4.2 million (9.2%) in 2001 primarily due to an increase in purchases to meet requirements for native load partially offset by a lower unit cost of the purchases.

Gas supply expenses decreased \$24.1 million (11.7%) in 2002 due to a decrease in cost of net gas supply (\$36.6 million), partially offset by an increase in the volume of gas delivered to the distribution system (\$12.5 million). Gas supply expenses increased \$9.3 million (4.7%) in 2001 primarily due to an increase in cost of net gas supply (\$36.2 million), partially offset by a decrease in the volume of gas delivered to the distribution system (\$26.9 million). The average unit cost per Mcf of purchased gas was \$4.19 in 2002, \$5.27 in 2001 and \$5.08 in 2000.

Other operation expenses increased \$40.5 million (24.1%) in 2002 primarily due to a full year amortization in 2002 of a regulatory asset created as a result of the workforce reduction costs associated with LG&E's VDT (\$17.0 million), higher costs for electric transmission primarily resulting from increased MISO costs (\$13.9 million), an increase in property and other insurance costs (\$3.9 million), an increase in pension costs due to change in pension assumptions to reflect current market conditions and change in market value of plan assets at the measurement date (\$3.7 million), and an increase in steam production costs (\$3.4 million). Other operation expenses increased \$31.9 million (23.4%) in 2001 primarily due to amortization of a regulatory asset resulting from workforce reduction costs associated with LG&E's VDT (\$13.0 million), an increase in pension expense (\$10.3 million) and an increase in outside services (\$8.5 million). Outside services increased in part due to the reclassification of expenses as a result of the formation of LG&E Services, as required by the SEC to comply with PUHCA.

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Maintenance expenses for 2002 increased \$1.5 million (2.6%) primarily due to gas distribution expenses for main remediation work (\$2.2 million). Maintenance expenses for 2001 decreased \$5.0 million (7.9%) primarily due to decreases in scheduled outages (\$2.8 million), and a decrease in software and communication equipment maintenance (\$2.8 million).

Depreciation and amortization increased \$5.5 million (5.5%) in 2002 and \$2.1 million (2.1%) in 2001 because of additional utility plant in service. The 2001 increase was offset by a decrease in depreciation rates resulting from a settlement order in December 2001 from the Kentucky Commission. Depreciation expenses decreased \$5.6 million as a result of the settlement order.

Variations in income tax expenses are largely attributable to changes in pre-tax income. LG&E's 2002 effective income tax rate increased to 37.2% from the 36.5% rate in 2001. See Note 7 of LG&E's Notes to Financial Statements under Item 8.

Property and other taxes decreased \$0.3 million (1.6%) in 2002. Property and other taxes decreased \$1.2 million (6.5%) in 2001 primarily due to a reduction in payroll taxes related to fewer employees as a result of workforce reductions and transfers to LG&E Services.

Other income - net decreased \$2.1 million (72.0%) in 2002 primarily due to increased costs for non-utility areas, \$1.3 million and decreases in the gain on sale of property \$0.8 million. Other income - net decreased \$2.0 million (40.5%) in 2001 primarily due to lower interest and dividend income.

Interest charges for 2002 decreased \$8.1 million (21.4%) primarily due to lower interest rates on variable rate debt (\$5.6 million) a decrease in debt to associated companies (\$0.8 million) and a decrease in interest associated with LG&E's accounts receivable securitization program (\$1.5 million). Interest charges for 2001 decreased \$5.3 million (12.2%) primarily due to lower interest rates on variable rate debt (\$2.2 million) and the retirement of short-term borrowings (\$8.1 million) partially offset by an increase in debt to associated companies (\$2.5 million) and an increase in interest associated with LG&E's accounts receivable securitization program (\$2.5 million). See Note 9 of LG&E's Notes to Financial Statements under Item 8.

LG&E's weighted average cost of long-term debt, including amortization of debt expense and interest rate swaps, was 3.87% at December 31, 2002 compared to 4.17% at December 31, 2001. See Note 9 of LG&E's Notes to Financial Statements under Item 8.

The rate of inflation may have a significant impact on LG&E's operations, its ability to control costs and the need to seek timely and adequate rate adjustments. However, relatively low rates of inflation in the past few years have moderated the impact on current operating results.

CRITICAL ACCOUNTING POLICIES/ESTIMATES

Preparation of financial statements and related disclosures in compliance with generally accepted accounting principles requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves

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judgments regarding future events, including legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied has not changed. Specific risks for these critical accounting policies are described in the following paragraphs. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Events rarely develop exactly as forecast and the best estimates routinely require adjustment. See also Note 1 of LG&E's Notes to Financial Statements under Item 8.

Unbilled Revenue - At each month end LG&E prepares a financial estimate that projects electric and gas usage that has been used by customers, but not billed. The estimated usage is based on known weather and days not billed. At December 31, 2002, a 10% change in these estimated quantities would cause revenue and accounts receivable to change by approximately \$5.0 million, including \$2.3 million for electric usage and \$2.7 million for gas usage. See also Note 1 of LG&E's Notes to Financial Statements under Item 8.

Benefit Plan Accounting - Judgments and uncertainties in benefit plan accounting include future rate of returns on pension plan assets, interest rates used in valuing benefit obligation, healthcare cost trend rates, and other actuarial assumptions.

LG&E's costs of providing defined-benefit pension retirement plans is dependent upon a number of factors, such as the rates of return on plan assets, discount rate, and contributions made to the plan. The market value of LG&E plan assets has been affected by declines in the equity market since the beginning of the fiscal year. As a result, at December 31, 2002, LG&E was required to recognize an additional minimum liability as prescribed by SFAS No. 87 Employers' Accounting for Pensions. The liability was recorded as a reduction to other comprehensive income, and did not affect net income for 2002. The amount of the liability depended upon the asset returns experienced in 2002 and contributions made by LG&E to the plan during 2002. Also, pension cost and cash contributions to the plan could increase in future years without a substantial recovery in the equity market. If the fair value of the plan assets exceeds the accumulated benefit obligation, the recorded liability will be reduced and other comprehensive income will be restored in the consolidated balance sheet.

The combination of poor market performance and a decrease in short-term corporate bond interest rates has created a divergence in the potential value of the pension liability and the actual value of the pension assets. These conditions could result in an increase in LG&E's funded accumulated benefit obligation and future pension expense. The primary assumptions that drive the value of the unfunded accumulated benefit obligation are the discount rate and expected return on plan assets.

LG&E made a contribution to the pension plan of \$83.1 million in January 2003.

A 1% increase or decrease in the assumed discount rate could have an approximate \$37.0 million positive or negative impact to the accumulated benefit obligation of LG&E.

See also Note 6 of LG&E's Notes to Financial Statements under Item 8.

Regulatory Mechanisms - Judgments and uncertainties include future regulatory decisions, impact of deregulation and competition on ratemaking process, and external regulator decisions.

Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates based upon Kentucky Commission orders. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections based upon orders by the Kentucky Commission. Management believes, based on orders, the existing regulatory assets and liabilities are probable of recovery. This determination reflects the current regulatory climate in the state. If future recovery of costs ceases to be probable the assets would be required to be recognized in current period earnings.

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LG&E has accrued in the financial statements an estimate of \$12.5 million for 2002 ESM, with collection from customer commencing in April 2003. The ESM is subject to Kentucky Commission approval.

See also Note 3 of LG&E's Notes to Financial Statements under Item 8.

NEW ACCOUNTING PRONOUNCEMENTS

SFAS No. 143, Accounting for Asset Retirement Obligations was issued in 2001. SFAS No. 143 establishes accounting and reporting standards for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs.

The effective implementation date for SFAS No. 143 is January 1, 2003. Management has calculated the impact of SFAS No. 143 and the recently released FERC NOPR No. RM02-7, Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations. As of January 1, 2003, LG&E recorded asset retirement obligation (ARO) assets in the amount of \$4.6 million and liabilities in the amount of \$9.3 million. LG&E also recorded a cumulative effect adjustment in the amount of \$5.3 million to reflect the accumulated depreciation and accretion of ARO assets at the transition date less amounts previously accrued under regulatory depreciation. LG&E recorded offsetting regulatory assets of \$5.3 million, pursuant to regulatory treatment prescribed under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. Also pursuant to SFAS No. 71, LG&E recorded regulatory liabilities in the amount of \$60,000 offsetting removal costs previously accrued under regulatory accounting in excess of amounts allowed under SFAS No. 143.

LG&E also expects to record ARO accretion expense of approximately \$617,000, ARO depreciation expense of approximately \$117,000 and an offsetting regulatory credit in the income statement of approximately \$734,000 in 2003, pursuant to regulatory treatment prescribed under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. The accretion, depreciation and regulatory credit will be annual adjustments. SFAS No. 143 will have no impact on the results of the operation of LG&E.

LG&E asset retirement obligations are primarily related to the final retirement of generating units. LG&E transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under SFAS No. 143, no material asset retirement obligations will be recorded for transmission and distribution assets.

LG&E adopted EITF No. 98-10, Accounting for Energy Trading and Risk Management Activities, effective January 1, 1999. This pronouncement required that energy trading contracts be marked to market on the balance sheet, with the gains and losses shown net in the income statement.

The EITF clarified accounting standards related to energy trading activities under EITF Issue 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities. EITF No. 02-03 established the following:

- Rescinded EITF No. 98-10,
- Contracts that do not meet the definition of a derivative under SFAS No. 133 should not be marked to fair market value, and
- Revenues should be shown in the income statement net of costs associated with trading activities, whether or not the trades are physically settled.

With the rescission of EITF No. 98-10, energy trading contracts that do not also meet the definition of a derivative under SFAS No. 133 must be accounted for as executory contracts. Contracts previously recorded at fair value under EITF No. 98-10 that are not also derivatives under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, must be restated to historical cost through a cumulative effect adjustment. The rescission of this standard had no impact on financial position or results of operations of LG&E since all contracts marked to market under EITF No. 98-10 are also within the scope of SFAS No. 133.

As a result of EITF No. 02-03, LG&E has netted the power purchased expense for trading activities against electric operating revenue to reflect this accounting change. LG&E applied this guidance to all prior periods, which had no impact on previously reported net income or common equity.

	2002	2001
Gross electric operating revenues	\$746,224	\$706,645
Less costs reclassified from power purchased	22,449	32,153
Net electric operating revenues reported	\$723,775	\$674,492
Gross power purchased	\$ 84,330	\$ 81,475
Less costs reclassified to revenues	22,449	32,153
Net power purchased reported	\$ 61,881	\$ 49,332

In January 2003, the Financial Accounting Standards Board issued Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51 (FIN 46). FIN 46 requires certain variable interest entities to be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. FIN 46 is effective immediately for all new variable interest entities created or acquired after January 31, 2003. For variable interest entities created or acquired prior to February 1, 2003, the provisions of FIN 46 must be applied for the first interim or annual period beginning after June 15, 2003. LG&E does not expect the adoption of this standard to have any impact on the financial position or results of operations.

LIQUIDITY AND CAPITAL RESOURCES

LG&E uses net cash generated from its operations and external financing to fund construction of plant and equipment and the payment of dividends. LG&E believes that such sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Operating Activities

Cash provided by operations was \$212.4 million, \$287.1 million and \$156.2 million in 2002, 2001, and 2000, respectively. The 2002 decrease compared to 2001 of \$74.7 million resulted primarily from the change in accounts receivable balances, including the sale of accounts receivable through the accounts receivable securitization program and a decrease in accounts payable and accrued taxes. The 2001 increase of \$130.9 million resulted primarily from an increase in accounts receivable, and a decrease in accrued taxes. See Note 1 of LG&E's Notes to Financial Statements under Item 8 for a discussion of accounts receivable securitization.

Investing Activities

LG&E's primary use of funds for investing activities continues to be for capital expenditures. Capital expenditures were \$220.4 million, \$253.0 million and \$144.2 million in 2002, 2001, and 2000, respectively. LG&E expects its capital expenditures for 2003 and 2004 to total approximately \$340.0 million, which consists primarily of construction estimates associated with installation of NOx equipment as described in the section titled "Environmental Matters," purchase of jointly owned CTs with KU and on-going construction for the distribution systems.

Net cash used for investment activities decreased \$28.7 million in 2002 compared to 2001 primarily due to the level of construction expenditures. CT expenditures were approximately \$35.9 million in 2002 and \$57.8 million in 2001. The \$107.9 million increase in net cash used in 2001 as compared to 2000 was due to NOx expenditures and the purchase of CTs.

Financing Activities

Net cash inflows for financing activities were \$22.5 million in 2002 and outflows of \$38.7 million and \$67.7 million in 2001 and 2000, respectively. In 2002, short-term borrowings increased \$98.9 million which were used in part for dividend payments of \$73.3 million. During 2001, short-term borrowings decreased \$20.4 million from 2000 and LG&E paid \$28.0 million in dividends.

During 2001, LG&E issued \$10.1 million of pollution control bonds resulting in net proceeds of \$9.7 million after issuance costs.

On March 6, 2002, LG&E refinanced its \$22.5 million and \$27.5 million unsecured pollution control bonds, both due September 1, 2026. The

replacement bonds, due September 1, 2026, are variable rate bonds and are secured by first mortgage bonds.

On March 22, 2002, LG&E refinanced its two \$35 million unsecured pollution control bonds due November 1, 2027. The replacement variable rate bonds are secured by first mortgage bonds and will mature November 1, 2027.

In October 2002, LG&E issued \$41.7 million variable rate pollution bonds due October 1, 2032, and exercised its call option on \$41.7 million, 6.55% pollution control bonds due November 1, 2020.

Under the provisions for LG&E's variable-rate pollution control bonds totaling \$246.2 million, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events, causing the bonds to be classified as current portion of long-term debt.

Future Capital Requirements

Future capital requirements may be affected in varying degrees by factors such as load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, market entry of competing electric power generators, changes in environmental regulations and other regulatory requirements. LG&E anticipates funding future capital requirements through operating cash flow, debt, and/or infusions of capital from its parent.

LG&E's debt ratings as of December 31, 2002, were:

	Moody's	S&P	Fitch
First mortgage bonds	A1	A	A+
Preferred stock	Baa1	BBB	A-
Commercial paper	P-1	A-2	F-1

These ratings reflect the views of Moody's, S&P and Fitch. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency.

Contractual Obligations

The following is provided to summarize LG&E's contractual cash obligations for periods after December 31, 2002 (in thousands of \$):

Contractual cash obligations	2003	Payments Due by Period			Total
		2004-2005	2006-2007	After 2007	
Short-term debt (a)	\$193,053	\$ -	\$ -	\$ -	\$193,053
Long-term debt (b)	288,800	-	-	328,104	616,904
Operating lease (c)	3,371	6,866	7,143	29,794	47,174
Unconditional purchase obligations (d)	10,773	20,268	21,632	184,544	237,217
Other long-term obligations (e)	28,401	95,151	-	-	123,552
Total contractual					

cash obligations (f) \$524,398 \$122,285 \$28,775 \$542,442 \$1,217,900

(a) Represents borrowings from parent company due within one year.

(b) Includes long-term debt of \$246.2 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. Maturity dates for these bonds range from 2017 to 2027.

(c) Operating lease represents the lease of LG&E's administrative office building.

(d) Represents future minimum payments under purchased power agreements through 2020.

(e) Represents construction commitments.

(f) LG&E does not expect to pay the \$246.2 million of long-term debt classified as a current liability in the consolidated balance sheets in 2003 as explained in (b) above. LG&E anticipates cash from operations and external financing will be sufficient to fund future obligations. LG&E anticipates refinancing a portion of its short-term debt with long-term debt in 2003.

Market Risks

LG&E is exposed to market risks from changes in interest rates and commodity prices. To mitigate changes in cash flows attributable to these

exposures, LG&E uses various financial instruments including derivatives. Derivative positions are monitored using techniques that include market value and sensitivity analysis.

See Note 1 and 4 of LG&E's Notes to Financial Statements under Item 8.

Interest Rate Sensitivity

LG&E has short-term and long-term variable rate debt obligations outstanding. At December 31, 2002, the potential change in interest expense associated with a 1% change in base interest rates of LG&E's unhedged debt is estimated at \$5.5 million after impact of interest rate swaps.

Interest rate swaps are used to hedge LG&E's underlying variable-rate debt obligations. These swaps hedge specific debt issuances and, consistent with management's designation, are accorded hedge accounting treatment. See Note 4 of LG&E's Notes to Financial Statements under Item 8.

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As of December 31, 2002, LG&E had swaps with a combined notional value of \$117.3 million. The swaps exchange floating-rate interest payments for fixed rate interest payments to reduce the impact of interest rate changes on LG&E's Pollution Control Bonds. The potential loss in fair value resulting from a hypothetical 1% adverse movement in base interest rates is estimated at \$10.8 million as of December 31, 2002. This estimate is derived from third party valuations. Changes in the market value of these swaps if held to maturity, as LG&E intends to do, will have no effect on LG&E's net income or cash flow. See Note 4 of LG&E's Notes to Financial Statements under Item 8.

Commodity Price Sensitivity

LG&E has limited exposure to market price volatility in prices of fuel and electricity, since its retail tariffs include the FAC and GSC commodity price pass-through mechanisms. LG&E is exposed to market price volatility of fuel and electricity in its wholesale activities.

Energy Trading & Risk Management Activities

LG&E conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns, in addition to the wholesale sale of excess asset capacity. Certain energy trading activities are accounted for on a mark-to-market basis in accordance with EITF 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities. Wholesale sales of excess asset capacity and wholesale purchases are treated as normal sales and purchases under SFAS No. 133 and SFAS No. 138 and are not marked-to-market.

The consensus reached by the EITF on EITF No. 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, to rescind EITF 98-10, effective for fiscal years after December 15, 2002, had no impact on LG&E's energy trading and risk management reporting as all contracts marked to market under EITF 98-10 are also within the scope of SFAS No. 133

The table below summarizes LG&E's energy trading and risk management activities for 2002 and 2001 (in thousands of \$).

	2002	2001
Fair value of contracts at beginning of period, net liability	\$ (186)	\$ (17)
Fair value of contracts when entered into during the period	(65)	3,441
Contracts realized or otherwise settled during the period	448	(2,894)
Changes in fair values due to changes in assumptions	(353)	(716)
Fair value of contracts at end of period, net liability	\$ (156)	\$ (186)

No changes to valuation techniques for energy trading and risk management activities occurred during 2002. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at December 31, 2002, have a maturity of less than one year and are valued using prices actively quoted for proposed or executed transactions or quoted by brokers.

LG&E maintains policies intended to minimize credit risk and revalues credit exposures daily to monitor compliance with those policies. At December 31, 2002, 86% of the trading and risk management commitments were with counterparties rated BBB- equivalent or better.

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Accounts Receivable Securitization

On February 6, 2001, LG&E implemented an accounts receivable securitization program. The purpose of this program is to enable LG&E to accelerate the receipt of cash from the collection of retail accounts receivable, thereby reducing dependence upon more costly sources of working capital. The securitization program allows for a percentage of eligible receivables to be sold. Eligible receivables are generally all receivables associated with retail sales that have standard terms and are not past due. LG&E is able to terminate the program at any time without penalty. If there is a significant deterioration in the payment record of the receivables by the retail customers or if LG&E fails to meet certain covenants regarding the program, the program may terminate at the election of the financial institutions. In this case, payments from retail customers would first be used to repay the financial institutions participating in the program, and would then be available for use by LG&E.

As part of the program, LG&E sold retail accounts receivables to a wholly owned subsidiary, LG&E R. Simultaneously, LG&E R entered into two separate three-year accounts receivable securitization facilities with two financial institutions and their affiliates whereby LG&E R can sell, on a revolving basis, an undivided interest in certain of its receivables and receive up to \$75 million from an unrelated third party purchaser. The effective cost of the receivables programs is comparable to LG&E's lowest cost source of capital, and is based on prime rated commercial paper. LG&E retains servicing rights of the sold receivables through two separate servicing agreements with the third party purchaser. LG&E has obtained an opinion from independent legal counsel indicating these transactions qualify as a true sale of receivables. As of December 31, 2002, the outstanding program balance was \$63.2 million. LG&E is considering unwinding its accounts receivable securitization arrangements involving LG&E R during 2003.

The allowance for doubtful accounts associated with the eligible securitized receivables was \$2.1 million at December 31, 2002. This allowance is based on historical experience of LG&E. Each securitization facility contains a fully funded reserve for uncollectible receivables.

RATES AND REGULATION

Following the purchase of Powergen by E.ON, E.ON became a registered holding company under PUHCA. As a result, E.ON, its utility subsidiaries, including LG&E, and certain of its non-utility subsidiaries are subject to extensive regulation by the SEC under PUHCA with respect to issuances and sales of securities, acquisitions and sales of certain utility properties, and intra-system sales of certain goods and services. In addition, PUHCA generally limits the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company. LG&E believes that it has adequate authority (including financing authority) under existing SEC orders and regulations to conduct its business. LG&E will seek additional authorization when necessary.

LG&E is subject to the jurisdiction of the Kentucky Commission in virtually all matters related to electric and gas utility regulation, and as such, its accounting is subject to SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. Given LG&E's competitive position in the marketplace and the status of regulation in the state of Kentucky, LG&E has no plans or intentions to discontinue its application of SFAS No. 71. See Note 3 of LG&E's Notes to Financial Statements under Item 8.

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Kentucky Commission Settlement Order - VDT Costs, ESM and Depreciation

During the first quarter 2001, LG&E recorded a \$144 million charge for a workforce reduction program. Primary components of the charge were separation benefits, enhanced early retirement benefits, and health care benefits. The result of this workforce reduction was the elimination of approximately 700 positions, accomplished primarily through a voluntary enhanced severance program.

On June 1, 2001, LG&E filed an application (VDT case) with the Kentucky Commission to create a regulatory asset relating to these first quarter 2001 charges. The application requested permission to amortize these costs over a four-year period. The Kentucky Commission also opened a case to review a new depreciation study and resulting depreciation rates implemented in 2001.

LG&E reached a settlement in the VDT case as well as the other cases involving depreciation rates and ESM with all intervening parties. The settlement agreement was approved by Kentucky Commission Order on December 3, 2001. The order allowed LG&E to set up a regulatory asset of \$141 million for the workforce reduction costs and begin amortizing these costs over a five-year period starting in April 2001. The first quarter 2001 charge of \$144 million represented all employees who had accepted a voluntary enhanced severance program. Some employees rescinded their participation in the voluntary enhanced severance program, thereby decreasing the original charge from \$144 million to \$141 million. The settlement will also reduce revenues approximately \$26 million through a surcredit on future bills to customers over the same five-year period. The surcredit represents stipulated net savings LG&E is expected to realize from implementation of best practices through the VDT. The agreement also established LG&E's new depreciation rates in effect December 2001, retroactive to January 1, 2001. The new depreciation rates decreased depreciation expense by \$5.6 million in 2001.

Environmental Cost Recovery

In June 2000, the Kentucky Commission approved LG&E's application for a CCN to construct up to three SCR NOx reduction facilities. The construction and subsequent operation of the SCRs is intended to reduce NOx emission levels to meet the EPA's mandated NOx emission level of 0.15 lbs./Mmbtu by May 2004. In its order, the Kentucky Commission ruled that LG&E's proposed plan for construction was "reasonable, cost-effective and will not result in the wasteful duplication of facilities." In October 2000, LG&E filed an application with the Kentucky

Commission to amend its Environmental Compliance Plan to reflect the addition of the proposed NOx reduction technology projects and to amend its Environmental Cost Recovery Tariff to include an overall rate of return on capital investments. Approval of LG&E's application in April 2001 allowed LG&E to begin to recover the costs associated with these new projects, subject to Kentucky Commission oversight during normal six-month and two-year reviews.

In May 2002, the Kentucky Commission initiated a periodic two-year review of LG&E's environmental surcharge. The review included the operation of the surcharge mechanism, determination of the appropriateness of costs included in the surcharge mechanism, recalculation of the cost of debt to reflect actual costs for the period under review, final determination of the amount of environmental revenues over-collected from customers, and a final determination of the amount of environmental costs and revenues to be "rolled-in" to base rates. A final order was issued on October 22, 2002, in which LG&E was ordered to refund \$325,000 to customers over the four-month period beginning November 2002 and ending February 2003. Additionally, LG&E was ordered to roll \$4.1 million into base rates and make corresponding adjustments to the monthly environmental surcharge filings to reflect that portion of environmental rate base now included in base rates on a going-forward basis.

In August 2002, LG&E filed an application with the Kentucky Commission to amend its compliance plan to allow recovery of the cost of new and additional environmental compliance facilities. The estimated capital cost of the additional facilities is \$71.1 million. The Kentucky Commission

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conducted a public hearing on the case on December 20, 2002, final briefs were filed on January 15, 2003, and a final order was issued February 11, 2003. The final order approved recovery of four new environmental compliance facilities totaling \$43.1 million. A fifth project, expansion of the land fill facility at the Mill Creek Station, was denied without prejudice with an invitation to reapply for recovery when required construction permits are approved. Cost recovery through the environmental surcharge of the four approved projects will begin with the bills rendered in April 2003.

ESM

LG&E's electric rates are subject to an ESM. The ESM, initially in place for three years beginning in 2000, sets an upper and lower point for rate of return on equity, whereby if LG&E's rate of return for the calendar year falls within the range of 10.5% to 12.5%, no action is necessary. If earnings are above the upper limit, the excess earnings are shared 40% with ratepayers and 60% with shareholders; if earnings are below the lower limit, the earnings deficiency is recovered 40% from ratepayers and 60% from shareholders. By order of the Kentucky Commission, rate changes prompted by the ESM filing go into effect in April of each year subject to a balancing adjustment in successive periods. LG&E made its second ESM filing on March 1, 2002, for the calendar year 2001 reporting period. LG&E is in the process of refunding \$441,000 to customers for the 2001 reporting period. LG&E estimated that the rate of return will fall below the lower limit, subject to Kentucky Commission approval, for the year ended December 31, 2002. The 2002 financial statements include an accrual to reflect the earnings deficiency of \$12.5 million to be recovered from customers commencing in April 2003.

On November 27, 2002, LG&E filed a revised ESM tariff which proposed continuance of the existing ESM through December 2005. The Kentucky Commission issued an Order suspending the ESM tariff one day making the effective date January 2, 2003. In addition, the Kentucky Commission is conducting a management audit to review the ESM plan and reassess its reasonableness in 2003. LG&E and interested parties will have the opportunity to provide recommendations for modification and continuance of the ESM or other forms of alternative or incentive regulation.

DSM

LG&E's rates contain a DSM provision. The provision includes a rate mechanism that provides concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. This program had allowed LG&E to recover revenues from lost sales associated with the DSM program. In May 2001, the Kentucky Commission approved LG&E's plan to continue DSM programs. This filing called for the expansion of the DSM programs into the service territory served by KU and proposed a mechanism to recover revenues from lost sales associated with DSM programs based on program planning engineering estimates and post-implementation evaluation.

Gas PBR

Since November 1, 1997, LG&E has operated under an experimental PBR mechanism related to its gas procurement activities. For each of the last five years, LG&E's rates have been adjusted to recover its portion of the savings (or expenses) incurred during each of the five 12-month periods beginning November 1 and ending October 31. Since its implementation on November 1, 1997, through October 31, 2002, LG&E has achieved \$38.1 million in savings. Of the total savings, LG&E has retained \$16.5 million, and the remaining portion of \$21.6 million has been distributed to customers. In December 2000, LG&E filed an application reporting on the operation of the experimental PBR and requested the Kentucky Commission to extend the PBR as a result of the benefits provided to both LG&E and its customers during the experimental period. Following the discovery and hearing process, the Kentucky Commission issued an order effective November 1, 2001, extending the experimental PBR program for an additional four years, and making other modifications, including changes to the sharing levels applicable to

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savings or expenses incurred under the PBR. Specifically, the Kentucky Commission modified the sharing mechanism to a 25%/75% Company/Customer sharing for all savings (and expenses) up to 4.5% of the benchmarked gas costs. Savings (and expenses) in excess of 4.5% of the benchmarked gas costs are shared at a 50%/50% level.

FAC

Prior to implementation of the electric PBR in July 1999, and following its termination in March 2000, LG&E employed an FAC mechanism, which under Kentucky law allowed LG&E to recover from customers the actual fuel costs associated with retail electric sales. In February 1999, LG&E received orders from the Kentucky Commission requiring a refund to retail electric customers of approximately \$3.9 million resulting from reviews of the FAC from November 1994, through April 1998. While legal challenges to the Kentucky Commission order were pending a comprehensive settlement was reached by all parties and approved by the Kentucky Commission on May 17, 2002. Thereunder, LG&E agreed to credit its fuel clause in the amount of \$720,000 (such credit provided over the course of June and July 2002), and the parties agreed on a prospective interpretation of the state's fuel adjustment clause regulation to ensure consistent and mutually acceptable application on a going-forward basis.

In December 2002, the Kentucky Commission initiated a two-year review of the operation of LG&E's FAC for the period November 2000 through October 2002. Testimony in the review case was filed on January 20, 2003 and a public hearing was held February 18, 2003. Issues addressed at that time included the establishment of the current base fuel factor to be included in LG&E's base rates, verification of proper treatment of purchased power costs during unit outages, and compliance with fuel procurement policies and practices.

Gas Rate Case

In March 2000, LG&E filed an application with the Kentucky Commission requesting an adjustment in LG&E's gas rates. In September 2000, the Kentucky Commission granted LG&E an annual increase in its base gas revenues of \$20.2 million effective September 28, 2000. The Kentucky Commission authorized a return on equity of 11.25%. The Kentucky Commission approved LG&E's proposal for a weather normalization billing adjustment mechanism that will normalize the effect of weather on base gas revenues from gas sales.

Wholesale Natural Gas Prices

On September 12, 2000, the Kentucky Commission issued an order establishing Administrative Case No. 384 - "An Investigation of Increasing Wholesale Natural Gas Prices and the Impacts of such Increase on the Retail Customers Served by Kentucky's Jurisdictional Natural Gas Distribution Companies". The impetus for this administrative proceeding was the escalation of wholesale natural gas prices during the summer of 2000.

The Kentucky Commission directed Kentucky's natural gas distribution companies, including LG&E, to file selected information regarding the individual companies' natural gas purchasing practices, expectations for the then-approaching winter heating season of 2000-2001, and potential actions which these companies might take to mitigate price volatility. On July 17, 2001, the Kentucky Commission issued an order encouraging the natural gas distribution companies in Kentucky to take various actions, among them to propose a natural gas hedge plan, consider performance-based ratemaking mechanisms, and to increase the use of storage.

In April 2002, in Case No. 2002-00136, LG&E proposed a hedging plan for the 2002/2003 winter heating season with three alternatives, the first two using a combination of storage and financial hedge instruments and the third relying upon storage alone. LG&E and the Attorney General, who represents Kentucky consumers, entered into a settlement which selected the third option. In August 2002, the Kentucky Commission approved the plan contemplated in the settlement. The Kentucky Commission validated the effectiveness of storage to mitigate potentially high winter gas prices by approving this natural gas hedging plan.

The Kentucky Commission also decided in Administrative Case No. 384 to engage a consultant to conduct a forward-looking audit of the gas procurement and supply procedures of Kentucky's largest natural gas distribution companies. The Kentucky Commission completed its audit in late 2002. The audit recognized LG&E as "efficient and effective [in the] procurement and management of significant quantities of natural gas supplies." The auditors also recognized that "the Company's residential gas prices have long been below averages for the U. S. and for the Commonwealth of Kentucky" which "demonstrates [LG&E's] effectiveness in [the] procurement and management of natural gas supplies." The audit also stated that the "Company's very impressive record in keeping its rates down provides sound evidence on the excellent job done in the area of gas supply procurement and management."

Kentucky Commission Administrative Case for Affiliate Transactions

In December 1997, the Kentucky Commission opened Administrative Case No. 369 to consider Kentucky Commission policy regarding cost allocations, affiliate transactions and codes of conduct governing the relationship between utilities and their non-utility operations and affiliates. The Kentucky Commission intended to address two major areas in the proceedings: the tools and conditions needed to prevent cost shifting and cross- subsidization between regulated and non-utility operations; and whether a code of conduct should be established to assure that non-utility segments of the holding company are not engaged in practices that could result in unfair competition caused by cost shifting from the non-utility affiliate to the utility. During the period September 1998 to February 2000,

the Kentucky Commission issued draft codes of conduct and cost allocation guidelines. In early 2000, the Kentucky General Assembly enacted legislation, House Bill 897, which authorized the Kentucky Commission to require utilities who provide nonregulated activities to keep separate accounts and allocate costs in accordance with procedures established by the Kentucky Commission. In the same bill, the General Assembly set forth provisions to govern a utility's activities related to the sharing of information, databases, and resources between its employees or an affiliate involved in the marketing or the provision of nonregulated activities and its employees or an affiliate involved in the provision of regulated services. The legislation became law in July 2000 and LG&E has been operating pursuant thereto since that time. On February 14, 2001, the Kentucky Commission published notice of their intent to promulgate new administrative regulations under the auspices of the new law. This effort is still on going.

Kentucky Commission Administrative Case for System Adequacy

On June 19, 2001, Kentucky Governor Paul E. Patton issued Executive Order 2001-771, which directed the Kentucky Commission to review and study issues relating to the need for and development of new electric generating capacity in Kentucky. The issues to be considered included the impact of new power plants on the electric supply grid, facility siting issues, and economic development matters, with the goal of ensuring a continued, reliable source of supply of electricity for the citizens of Kentucky and the continued environmental and economic vitality of Kentucky and its communities. In response to that Executive Order, in July 2001 the Kentucky Commission opened Administrative Case No. 387 to review the adequacy of Kentucky's generation capacity and transmission system. Specifically, the items reviewed were the appropriate level of reliance on purchased power, the appropriate reserve margins to meet existing and future electric demand, the impact of spikes in natural gas prices on electric utility planning strategies, and the adequacy of Kentucky's electric transmission facilities. LG&E, as a party to this proceeding, filed written testimony and responded to two requests for information. Public hearings were held and in October 2001, LG&E filed a final brief in the case. In December 2001, the Kentucky Commission issued an order in which it noted that LG&E is responsibly addressing the long-term supply needs of native load customers and that current reserve margins are appropriate. However, due to the rapid pace of change in the industry, the order also requires LG&E to provide an annual assessment of supply resources, future demand, reserve margin, and the need for new resources.

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Regarding the transmission system, the Kentucky Commission concluded that the transmission system within Kentucky can reliably serve native load and a significant portion of the proposed new unregulated power plants. However, it will not be able to handle the volume of transactions envisioned by FERC without future upgrades, the costs of which should be borne by those for whom the upgrades are required.

The Kentucky Commission pledged to continue to monitor all relevant issues and advocate Kentucky's interests at all opportunities.

FERC SMD NOPR

On July 31, 2002, FERC issued a NOPR in Docket No. RM01-12-000 which would substantially alter the regulations governing the nation's wholesale electricity markets by establishing a common set of rules -- SMD. The SMD NOPR would require each public utility that owns, operates, or controls interstate transmission facilities to become an Independent Transmission Provider (ITP), belong to an RTO that is an ITP, or contract with an ITP for operation of its transmission assets. It would also establish a standardized congestion management system, real-time and day-ahead energy markets, and a single transmission service for network and point-to-point transmission customers. Review of the proposed rulemaking is underway and a final rule is expected during 2003. While it is expected that the SMD final rule will affect LG&E revenues and expenses, the specific impact of the rulemaking is not known at this time.

MISO

LG&E is a member of the MISO, which began commercial operations on February 1, 2002. MISO now has operational control over LG&E's high-voltage transmission facilities (100 kV and greater), while LG&E continues to control and operate the lower voltage transmission subject to the terms and conditions of the MISO OATT. As a transmission-owning member of MISO, LG&E also incurs administrative costs of MISO pursuant to Schedule 10 of the MISO OATT.

MISO also proposed to implement a congestion management system. FERC directed the MISO to coordinate its efforts with FERC's Rulemaking on SMD. On September 24, 2002, the MISO filed new rate schedules designated as Schedules 16 and 17, which provide for the collection of costs incurred by the MISO to establish day-ahead and real-time energy markets. The MISO proposed to recover these costs under Schedules 16 and 17 once service commences. If approved by FERC, these schedules will cause LG&E to incur additional costs. LG&E opposes the establishment of Schedules 16 and 17. This effort is still on-going and the ultimate impact of the two schedules, if approved, is not known at this time.

Merger Surcredit

As part of the LG&E Energy merger with KU Energy in 1998, LG&E Energy estimated non-fuel savings over a ten-year period following the merger. Costs to achieve these savings for LG&E of \$50.2 million were recorded in the second quarter of 1998, \$18.1 million of which was deferred and amortized over a five-year period pursuant to regulatory orders. Primary components of the merger costs were separation benefits, relocation costs, and transaction fees, the majority of which were paid by December 31, 1998. LG&E expensed the remaining costs associated with the merger (\$32.1 million) in the second quarter of 1998.

In approving the merger, the Kentucky Commission adopted LG&E's proposal to reduce its retail customers' bills based on one-half of the estimated merger-related savings, net of deferred and amortized amounts, over a five-year period. The surcredit mechanism provides that 50% of the net non-fuel cost savings estimated to be achieved from the merger be provided to ratepayers through a monthly bill credit, and 50% be retained by the Companies, over a five-year period. The surcredit was allocated 53% to KU and 47% to LG&E. In that same order, the Commission required LG&E and KU,

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after the end of the five-year period, to present a plan for sharing with customers the then-projected non-fuel savings associated with the merger. The Companies submitted this filing on January 13, 2003, proposing to continue to share with customers, on a 50%/50% basis, the estimated fifth-year gross level of non-fuel savings associated with the merger. The filing is currently under review.

Any fuel cost savings are passed to Kentucky customers through the fuel adjustment clause. See FAC above.

Environmental Matters

The Clean Air Act imposed stringent new SO₂ and NO_x emission limits on electric generating units. LG&E previously had installed scrubbers on all of its generating units. LG&E's strategy for Phase II SO₂ reductions, which commenced January 1, 2000, is to increase scrubber removal efficiency to delay additional capital expenditures and may also include fuel switching or upgrading scrubbers. LG&E met the NO_x emission requirements of the Act through installation of low-NO_x burner systems. LG&E's compliance plans are subject to many factors including developments in the emission allowance and fuel markets, future regulatory and legislative initiatives, and advances in clean air control technology. LG&E will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner.

In September 1998, the EPA announced its final "NO_x SIP Call" rule requiring states to impose significant additional reductions in NO_x emissions by May 2003, in order to mitigate alleged ozone transport impacts on the Northeast region. The Commonwealth of Kentucky is currently in the process of revising its SIP to require reductions in NO_x emissions from coal-fired generating units to the 0.15 lb./Mmbtu level on a system-wide basis. In related proceedings in response to petitions filed by various Northeast states, in December 1999, EPA issued a final rule pursuant to

Section 126 of the Clean Air Act directing similar NO_x reductions from a number of specifically targeted generating units including all LG&E units. As a result of appeals to both rules, the compliance date was extended to May 2004. All LG&E generating units are subject to the May 2004 compliance date under these NO_x emissions reduction rules.

LG&E is currently implementing a plan for adding significant additional NO_x controls to its generating units. Installation of additional NO_x controls will proceed on a phased basis, with installation of controls commencing in late 2000 and continuing through the final compliance date. LG&E estimates that it will incur total capital costs of approximately \$178 million to reduce its NO_x emissions to the 0.15 lb./Mmbtu level on a company-wide basis. In addition, LG&E will incur additional operating and maintenance costs in operating new NO_x controls. LG&E believes its costs in this regard to be comparable to those of similarly situated utilities with like generation assets. LG&E had anticipated that such capital and operating costs are the type of costs that are eligible for recovery from customers under its environmental surcharge mechanism and believed that a significant portion of such costs could be recovered. In April 2001, the Kentucky Commission granted recovery of these costs for LG&E.

LG&E is also monitoring several other air quality issues which may potentially impact coal-fired power plants, including the appeal of the D.C. Circuit's remand of the EPA's revised air quality standards for ozone and particulate matter, measures to implement EPA's regional haze rule, and EPA's December 2000 determination to regulate mercury emissions from power plants. In addition, LG&E is currently working with local regulatory authorities to review the effectiveness of remedial measures aimed at controlling particulate matter emissions from its Mill Creek Station. LG&E previously settled a number of property damage claims from adjacent residents and completed significant remedial measures as part of its ongoing capital construction program. LG&E is in the process of converting the Mill Creek Station to wet stack operation in an effort to resolve all outstanding issues related to particulate matter emissions.

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LG&E owns or formerly owned three properties which are the location of past MGP operations. Various contaminants are typically found at such former MGP sites and environmental remediation measures are frequently required. With respect to the sites, LG&E has completed cleanups, obtained regulatory approval of site management plans, or reached agreements for other parties to assume responsibility for cleanup. Based on currently available information, management estimates that it will incur additional costs of \$400,000. Accordingly, an accrual of \$400,000 has been recorded in the accompanying financial statements at December 31, 2002 and 2001.

See Note 11 of LG&E's Notes to Financial Statements under Item 8 for an additional discussion of environmental issues.

Deferred Income Taxes

LG&E expects to have adequate levels of taxable income to realize its recorded deferred tax assets. At December 31, 2002, deferred tax assets totaled \$98.2 million and were principally related to expenses attributable to LG&E's pension plans and post retirement benefit obligations.

FUTURE OUTLOOK

Competition and Customer Choice

LG&E has moved aggressively over the past decade to be positioned for the energy industry's shift to customer choice and a competitive market for energy services. Specifically, LG&E has taken many steps to prepare for the expected increase in competition in its business, including support for PBR structures; aggressive cost reduction activities; strategic acquisitions, dispositions and growth initiatives; write-offs of previously deferred expenses; an increase in focus on commercial and industrial customers; an increase in employee training; and necessary corporate and business unit realignments.

In December 1997, the Kentucky Commission issued a set of principles which was intended to serve as its guide in consideration of issues relating to industry restructuring. Among the issues addressed by these principles are: consumer protection and benefit, system reliability, universal service, environmental responsibility, cost allocation, stranded costs and codes of conduct. During 1998, the Kentucky Commission and a task force of the Kentucky General Assembly had each initiated proceedings, including meetings with representatives of utilities, consumers, state agencies and other groups in Kentucky, to discuss the possible structure and effects of energy industry restructuring in Kentucky.

In November 1999, the task force issued a report to the Governor of Kentucky and a legislative agency recommending no general electric industry restructuring actions during the 2000 legislative session. No general restructuring actions have been taken to date by the legislature.

Thus, at the time of this report, neither the Kentucky General Assembly nor the Kentucky Commission has adopted or approved a plan or timetable for retail electric industry competition in Kentucky. The nature or timing of the ultimate legislative or regulatory actions regarding industry restructuring and their impact on LG&E, which may be significant, cannot currently be predicted.

While many states have moved forward in providing retail choice, many others have not. Some are reconsidering their initiatives and have even delayed implementation.

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KU:

GENERAL

The following discussion and analysis by management focuses on those factors that had a material effect on KU's financial results of operations and financial condition during 2002, 2001, and 2000 and should be read in connection with the financial statements and notes thereto.

Some of the following discussion may contain forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may materially vary. Factors that could cause actual results to materially differ include:

general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; actions by credit rating agencies; and other factors described from time to time in KU's reports to the SEC, including Exhibit No. 99.01 to the Annual Report.

MERGERS and ACQUISITIONS

On December 11, 2000, LG&E Energy was acquired by Powergen for cash of approximately \$3.2 billion or \$24.85 per share and the assumption of all of LG&E Energy's debt. As a result of the acquisition, LG&E Energy became a wholly owned subsidiary of Powergen and, as a result, KU became an indirect subsidiary of Powergen. KU has continued its separate identity and serves customers in Kentucky, Virginia and Tennessee under its existing name. The preferred stock and debt securities of KU were not affected by this transaction and KU continued to file SEC reports. Following the acquisition, Powergen became a registered holding company under PUHCA and KU, as a subsidiary of a registered holding company, became subject to additional regulation under PUHCA. See "Rates and Regulation" under Item 1.

On July 1, 2002, E.ON, a German company, completed its acquisition of Powergen plc (now Powergen Limited). As a result, LG&E and KU became indirect subsidiaries of E.ON. E.ON had announced its pre-conditional cash offer of 5.1 billion pounds sterling (\$7.3 billion) for Powergen on April 9, 2001. Following the acquisition, E.ON became a registered holding company under PUHCA.

As contemplated in their regulatory filings in connection with the E.ON acquisition, E.ON, Powergen and LG&E Energy completed an administrative reorganization to move the LG&E Energy group from an indirect Powergen subsidiary to an indirect E.ON subsidiary. This reorganization was effective in March 2003.

RESULTS OF OPERATIONS

Net Income

KU's net income in 2002 decreased \$3.0 million compared to 2001. The decrease resulted primarily from higher transmission operating expenses, an increase in amortization of regulatory assets, and increased property insurance, partially offset by an increase in sales to retail customers and lower interest expenses.

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KU's net income in 2001 was relatively flat as compared to 2000 with an increase of \$.9 million. The increase resulted primarily from decreased depreciation, interest expenses and property and other taxes, partially offset by higher pension related expenses and amortization of regulatory assets.

Revenues

A comparison of operating revenues for the years 2002 and 2001, excluding the provision for rate collections (refunds), with the immediately preceding year reflects both increases and decreases which have been segregated by the following principal causes (in thousands of \$):

Cause	Increase (Decrease) From Prior Period	
	2002	2001
Retail sales:		
Fuel clause adjustments	\$ 18,223	\$ 10,220
KU/LG&E Merger surcredit	(2,641)	(3,856)
Environmental cost recovery surcharge	3,781	1,458
Demand side management	1,570	-
Performance based rate	-	1,747
Electric rate reduction	-	(5,395)
VDT surcredit	(527)	(372)
Variation in sales volumes, and other	46,601	(1,627)
Total retail sales	67,007	2,175
Wholesale sales	(47,178)	24,889
Other	7,132	1,202
Total	\$ 26,961	\$ 28,266

Electric revenues increased in 2002 primarily due to an increase in retail sales due to warmer weather and an increase in the recovery of fuel costs passed through the FAC. Cooling degree days for 2002 increased 26% over 2001. The increase in retail sales was partially offset by a decrease in wholesale sales volumes. The decrease in wholesale sales was due in large part to fewer megawatts available due to increased retail sales. Electric revenues increased in 2001 primarily due to an increase in wholesale activity and an increase in the recovery of fuel costs passed through the FAC partially offset by a rate reduction ordered by Kentucky Commission in 2000 and lower sales volumes.

Expenses

Fuel for electric generation comprises a large component of KU's total operating expenses. KU's Kentucky jurisdictional electric rates are subject to a FAC whereby increases or decreases are reflected in the FAC factor, subject to the approval of the Kentucky Commission. KU's wholesale and Virginia jurisdictional electric rates contain a fuel adjustment clause whereby increases or decreases in the cost of fuel are reflected in rates, subject to the approval of FERC and the Virginia Commission, respectively.

Fuel for electric generation increased \$13.1 million (5.5%) in 2002 because of an increase in the cost of coal burned (\$29.7 million), partially offset by a decrease in generation (\$16.5 million). Fuel for electric generation increased \$17.1 million (7.8%) in 2001 because of an increase in the cost of coal burned (\$21.8 million), partially offset by a decrease in generation (\$4.7 million). The average delivered cost per ton of coal purchased was \$31.44 in 2002, \$27.84 in 2001 and \$25.63 in 2000.

Power purchased expense increased \$13.0 million (11.0%) in 2002 primarily due to an increase in purchases to meet requirements for native load partially offset by a decrease in purchase price. Power purchased expense increased \$10.0 million (9.3%) in 2001 primarily due to an increase in purchases to meet requirements for native load partially offset by a decrease in purchase price.

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Other operation expenses increased \$25.8 million (21.8%) in 2002. The primary cause for the increase was the full year amortization in 2002 of a regulatory asset created as a result of the workforce reduction associated with KU's VDT of \$6.5 million, higher costs for electric transmission primarily resulting from increased MISO costs of \$7.4 million, an increase in property insurance costs of \$2.8 million, an increase in employee benefit costs due to changes in pension assumptions to reflect current market conditions and changes in market value of plan assets at the measurement date of \$1.7 million, and an increase in outside services of \$4.9 million. Other operation expenses increased \$10.3 million (9.5%) in 2001. The primary cause for the increase was the amortization of a regulatory asset as a result of the workforce reduction associated with KU's VDT of \$5.0 million and an increase in pension expense of \$5.5 million.

Maintenance expenses increased \$5.9 million (10.3%) in 2002 primarily due to increases in steam maintenance of \$6.1 million related to

annual outages at the Ghent, Green River, and Tyrone steam facilities. Maintenance expenses for 2001 decreased \$4.6 million (7.5%) primarily due to decreased repairs to steam facilities (\$6.5 million).

Depreciation and amortization increased \$5.2 million (5.7%) in 2002 primarily due to an increase in plant in service. Depreciation and amortization decreased \$8.0 million (8.1%) in 2001 primarily due to a reduction in depreciation rates as a result of a settlement order in December 2001 from the Kentucky Commission. Depreciation expenses decreased by \$6.0 million as a result of the settlement order.

Variations in income tax expense are largely attributable to changes in pre-tax income. The 2002 effective income tax rate decreased to 34.9% from the 35.9% rate in 2001. See Note 7 of KU's Notes to Financial Statements under Item 8.

Property and other taxes increased \$1.1 million (7.6%) in 2002 due to higher property taxes and payroll taxes. Property and other taxes decreased \$3.1 million (18.2%) in 2001 due to decreases in payroll taxes related to fewer employees as a result of workforce reductions and transfers to LG&E Energy Services Company.

Other income-net increased \$1.5 million (16.8%) in 2002 primarily due to a non-recurring increase in earnings from KU's equity earnings in a minority interest of \$5.2 million, partially offset by a gain on disposition of property in 2001, \$1.8 million, lower interest and dividend income from investments, \$0.7 million, and higher benefit and other costs, \$1.4 million. The increased equity earnings in 2002 are due to the gain on the sale of emissions allowances. Other income-net increased \$2.1 million (30.5%) in 2001 due to an increase in the gain on sale of assets.

Interest charges decreased \$8.3 million (24.5%) in 2002 as compared to 2001 due to lower interest rates on variable rate debt and refinancing of long term debt with lower interest rates, \$8.0 million. Interest charges decreased \$5.4 million (13.7%) in 2001 from 2000 due to lower interest rates on variable rate debt, \$4.6 million, the retirement of short-term borrowings, \$1.6 million, lower interest on debt to parent company, \$1.2 million, partially offset by an increase in interest associated with KU's accounts receivable securitization program, \$1.8 million.

KU's weighted average cost of long-term debt, including amortization of debt expense and interest rate swaps, was 3.30% at December 31, 2002 compared to 4.91% at December 31, 2001. See Note 9 of KU's Notes to Financial Statements under Item 8.

The rate of inflation may have a significant impact on KU's operations, its ability to control costs and the need to seek timely and adequate rate adjustments. However, relatively low rates of inflation in the past few years have moderated the impact on current operating results.

CRITICAL ACCOUNTING POLICIES/ESTIMATES

Preparation of financial statements and related disclosures in compliance with generally accepted accounting principles requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied has not changed. Specific risks for these critical accounting policies are described in the following paragraphs. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Events rarely develop exactly as forecast and the best estimates routinely require adjustment. See also Note 1 of KU's Notes to Financial Statements under Item 8.

Unbilled Revenue - At each month end KU prepares a financial estimate that projects electric usage that has been used by customers, but not billed. The estimated usage is based on known weather and days not billed. At December 31, 2002, a 10% change in these estimated quantities would cause revenue and accounts receivable to change by approximately \$4.2 million. See also Note 1 of KU's Notes to Financial Statements under Item 8.

Benefit Plan Accounting - Judgments and uncertainties in benefit plan accounting include future rate of returns on pension plan assets, interest rates used in valuing benefit obligation, healthcare cost trend rates and other actuarial assumptions.

KU's costs of providing defined-benefit pension retirement plans is dependent upon a number of factors, such as the rates of return on plan assets, discount rate, and contributions made to the plan. The market value of KU plan assets has been affected by declines in the equity market since the beginning of the fiscal year. As a result, at December 31, 2002, KU was required to recognize an additional minimum liability as prescribed by SFAS No. 87 Employers' Accounting for Pensions. The liability was recorded as a reduction to other comprehensive income, and did not affect net income for 2002. The amount of the liability depended upon the asset returns experienced in 2002 and contributions made by KU to the plan during 2002. Also, pension cost and cash contributions to the plan could increase in future years without a substantial recovery in the equity market. If the fair value of the plan assets exceeds the accumulated benefit obligation, the recorded liability will be reduced and other comprehensive income will be restored in the consolidated balance sheet.

The combination of poor market performance and a decrease in short-term corporate bond interest rates has created a divergence in the potential value of the pension liability and the actual value of the pension assets. These conditions could result in an increase in KU's funded

accumulated benefit obligation and future pension expense. The primary assumptions that drive the value of the unfunded accumulated benefit obligation are the discount rate and expected return on plan assets.

KU made a contribution to the pension plan of \$3.5 million in January 2003.

A 1% increase or decrease in the assumed discount rate could have an approximate \$26.0 million positive or negative impact to the accumulated benefit obligation of KU.

See also Note 6 of KU's Notes to Financial Statements under Item 8.

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Regulatory Mechanisms - Judgments and uncertainties include future regulatory decisions, the impact of deregulation and competition on the ratemaking process and external regulator decisions.

Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates based upon Kentucky Commission orders. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections based upon orders by the Kentucky Commission. Management believes, based on orders, the existing regulatory assets and liabilities are probable of recovery. This determination reflects the current regulatory climate in the state. If future recovery of costs ceases to be probable the assets would be required to be recognized in current period earnings.

KU has accrued in the financial statements, an estimate of \$13.5 million for 2002 ESM, with collection from customers commencing in April 2003. The ESM is subject to Kentucky Commission approval.

See also Note 3 of KU's Notes to Financial Statements under Item 8.

NEW ACCOUNTING PRONOUNCEMENTS

SFAS No. 143, Accounting for Asset Retirement Obligations was issued in 2001. SFAS No. 143 establishes accounting and reporting standards for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs.

The effective implementation date for SFAS No. 143 is January 1, 2003. Management has calculated the impact of SFAS No. 143 and the recently released FERC NOPR No. RM02-7, Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations. As of January 1, 2003, KU recorded asset retirement obligation (ARO) assets in the amount of \$8.6 million and liabilities in the amount of \$18.5 million. KU also recorded a cumulative effect adjustment in the amount of \$9.9 million to reflect the accumulated depreciation and accretion of ARO assets at the transition date less amounts previously accrued under regulatory depreciation. KU recorded offsetting regulatory assets of \$9.9 million, pursuant to regulatory treatment prescribed under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. Also pursuant to SFAS No. 71, KU recorded regulatory liabilities in the amount of \$888,000 offsetting removal costs previously accrued under regulatory accounting in excess of amounts allowed under SFAS No. 143.

KU also expects to record ARO accretion expense of approximately \$1.2 million, ARO depreciation expense of approximately \$176,000 and an offsetting regulatory credit in the income statement of approximately \$1.4 million in 2003, pursuant to regulatory treatment prescribed under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. The accretion, depreciation and regulatory credit will be annual adjustments. SFAS No. 143 will have no impact on the results of the operation of KU.

KU asset retirement obligations are primarily related to the final retirement of generating units. KU transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under SFAS No. 143, no material asset retirement obligations will be recorded for transmission and distribution assets.

KU adopted EITF No. 98-10, Accounting for Energy Trading and Risk Management Activities, effective January 1, 1999. This pronouncement required that energy trading contracts be marked to market on the balance sheet, with the gains and losses shown net in the income statement.

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The EITF clarified accounting standards related to energy trading activities under EITF Issue 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities. EITF No. 02-03 established the following:

- Rescinded EITF No. 98-10,
- Contracts that do not meet the definition of a derivative under SFAS No.133 should not be marked to fair market value, and
- Revenues should be shown in the income statement net of costs associated with trading activities, whether or not the trades are physically settled.

With the rescission of EITF No. 98-10, energy trading contracts that do not also meet the definition of a derivative under SFAS No. 133 must be accounted for as executory contracts. Contracts previously recorded at fair value under EITF No. 98-10 that are not also derivatives under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, must be restated to historical cost through a cumulative effect adjustment. The rescission of this standard had no impact on financial position or results of operations of KU since all contracts marked to market under EITF No. 98- 10 are also within the scope of SFAS No. 133.

As a result of EITF No. 02-03, KU has netted the power purchased expense for trading activities against electric operating revenue to reflect this accounting change. KU applied this guidance to all prior periods, which had no impact on previously reported net income or common equity.

	2002	2001
Gross electric operating revenues	\$875,192	\$860,426
Less costs reclassified from power purchased	26,555	38,751
Net electric operating revenues reported	\$848,637	\$821,675
Gross power purchased	\$157,955	\$157,161
Less costs reclassified to revenues	26,555	38,751
Net power purchased reported	\$131,400	\$118,410

In January 2003, the Financial Accounting Standards Board issued Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51 (FIN 46). FIN 46 requires certain variable interest entities to be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. FIN 46 is effective immediately for all new variable interest entities created or acquired after January 31, 2003. For variable interest entities created or acquired prior to February 1, 2003, the provisions of FIN 46 must be applied for the first interim or annual period beginning after June 15, 2003. KU does not expect the adoption of this standard to have any impact on the financial position or results of operations.

LIQUIDITY AND CAPITAL RESOURCES

KU uses net cash generated from its operations and external financing to fund construction of plant and equipment and the payment of dividends. KU believes that such sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Operating Activities

Cash provided by operations was \$175.8 million, \$188.1 million and \$176.3 million in 2002, 2001 and 2000, respectively. The 2002 decrease from 2001 of \$12.3 million was primarily the result of a decrease in accrued taxes and changes in accounts receivable. The 2001 increase resulted from sale of accounts receivable through a securitization program. See Note 1 of KU's Notes to Financial Statements under Item 8 for a discussion of accounts receivable securitization.

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Investing Activities

KU's primary use of funds for investing activities continues to be for capital expenditures. Capital expenditures were \$237.9 million, \$142.4 million and \$100.3 million in 2002, 2001 and 2000, respectively. KU expects its capital expenditures for 2003 and 2004 will total approximately \$550.0 million, which consists primarily of construction costs associated with installation of NOx equipment as described in the section titled "Environmental Matters," purchase of jointly owned CTs with LG&E and on going construction for the distribution system.

Net cash used for investment activities increased \$99.0 million in 2002 compared to 2001 and \$38.6 million in 2001 compared to 2000 primarily due to the level of construction expenditures. NOx expenditures increased \$50.6 million and CT expenditures increased \$27.0 million in 2002.

Financing Activities

Net cash inflows from financing activities were \$64.2 million in 2002 and outflows of \$46.2 million and \$82.4 million in 2001 and 2000, respectively. In 2002, short-term debt increased \$72.0 million from 2001. In 2001, short-term debt decreased \$13.4 million from 2000 and KU paid \$32.8 million in dividends.

In May 2002, KU issued \$37.93 million variable rate pollution control Series 12, 13, 14 and 15 due February 1, 2032, and exercised its call option on \$37.93 million, 6.25% pollution control Series 1B, 2B, 3B, and 4B due February 1, 2018.

In September 2002, KU issued \$96 million variable rate pollution control Series 16 due October 1, 2032, and exercised its call option on \$96 million, 7.45% pollution control Series 8 due September 15, 2016.

Future Capital Requirements

Future capital requirements may be affected in varying degrees by factors such as load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, market entry of competing electric power generators, changes in environmental regulations and other regulatory requirements. KU anticipates funding future capital requirements through operating cash flow, debt, and/or infusion of capital from its parent.

KU's debt ratings as of December 31, 2002, were:

	Moody's	S&P	Fitch
First mortgage bonds	A1	A	A+
Preferred stock	Baa1	BBB	A-
Commercial paper	P-1	A-2	F-1

These ratings reflect the views of Moody's, S&P and Fitch. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency.

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Contractual Obligations

The following is provided to summarize KU's contractual cash obligations for periods after December 31, 2002 (in thousands of \$):

Contractual cash Obligations	Payments Due by Period				
	2003	2004-2005	2006-2007	After 2007	Total
Short-term debt (a)	\$119,490	\$ -	\$ -	\$ -	\$ 119,490
Long-term debt (b)	153,930	-	89,000	257,562	500,492
Unconditional purchase obligations (c)	34,317	79,306	79,878	643,946	837,447
Other long-term obligations (d)	128,199	201,249	-	-	329,448
Total contractual cash obligations (e)	\$435,936	\$280,555	\$168,878	\$901,508	\$1,786,877

(a) Represents borrowings from parent company due within one year.

(b) Includes long-term debt of \$91.9 million is classified as a current liability because the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. Maturity dates for the bonds range from 2024 to 2032.

(c) Represents future minimum payments under purchased power agreements through 2020.

(d) Represents construction commitments.

(e) KU does not expect to pay the \$91.9 million of long-term debt classified as a current liability in the consolidated balance sheets in 2003 as explained in (b) above. KU anticipates cash from operations and external financing will be sufficient to fund future obligations. KU anticipates refinancing a portion of its short-term debt with long-term debt in 2003.

Market Risks

KU is exposed to market risks from changes in interest rates and commodity prices. To mitigate changes in cash flows attributable to these exposures, KU uses various financial instruments including derivatives. Derivative positions are monitored using techniques that include market value and sensitivity analysis.

See Notes 1 and 4 of KU's Notes to Financial Statements under Item 8.

Interest Rate Sensitivity

KU has short-term and long-term variable rate debt obligations outstanding. At December 31, 2002, the potential change in interest expense associated with a 1% change in base interest rates of KU's variable rate debt is estimated at \$5.2 million after impact of interest rate swaps.

Interest rate swaps are used to hedge KU's underlying debt obligations. These swaps hedge specific debt issuances and, consistent with management's designation, are accorded hedge accounting treatment.

As of December 31, 2002, KU has swaps with a combined notional value of \$153 million. The swaps exchange fixed-rate interest payments for floating rate interest payments on KU's Series P, R, and PCS-9 Bonds. The potential loss in fair value resulting from a hypothetical 1% adverse

movement in base interest rates is estimated at \$6.9 million as of December 31, 2002. This estimate is derived from third party valuations. Changes in the market value of these swaps if held to maturity, as KU intends to do, will have no effect on KU's net income or cash flow. See Note 4 of KU's Notes to Financial Statements under Item 8.

Commodity Price Sensitivity

KU has limited exposure to market price volatility in prices of fuel and electricity, since its retail tariffs include the FAC commodity price pass-through mechanism. KU is exposed to market price volatility of fuel and electricity in its wholesale activities.

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Energy Trading & Risk Management Activities

KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns, in addition to the wholesale sale of excess asset capacity. Certain energy trading activities are accounted for on a mark-to-market basis in accordance with EITF 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities. Wholesale sales of excess asset capacity and wholesale purchases are treated as normal sales and purchases under SFAS No. 133 and SFAS No. 138 and are not marked-to-market.

The consensus reached by the EITF on EITF No. 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, to rescind EITF 98-10, effective for fiscal years after December 15, 2002, had no impact on KU's energy trading and risk management reporting as all contracts marked to market under EITF 98-10 are also within the scope of SFAS No. 133.

The table below summarizes KU's energy trading and risk management activities for 2002 and 2001(in thousands of \$).

	2002	2001
Fair value of contracts at beginning of period, net liability	\$ (186)	\$ (17)
Fair value of contracts when entered into during the period	(65)	3,441
Contracts realized or otherwise settled during the period	448	(2,894)
Changes in fair values due to changes in assumptions	(353)	(716)
Fair value of contracts at end of period, net liability	\$ (156)	\$ (186)

No changes to valuation techniques for energy trading and risk management activities occurred during 2002. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at December 31, 2002 have a maturity of less than one year and are valued using prices actively quoted for proposed or executed transactions or quoted by brokers.

KU maintains policies intended to minimize credit risk and revalues credit exposures daily to monitor compliance with those policies. At December 31, 2002, 86% of the trading and risk management commitments were with counterparties rated BBB- equivalent or better.

Accounts Receivable Securitization

On February 6, 2001, KU implemented an accounts receivable securitization program. The purpose of this program is to enable KU to accelerate the receipt of cash from the collection of retail accounts receivable, thereby reducing dependence upon more costly sources of working capital. The securitization program allows for a percentage of eligible receivables to be sold. Eligible receivables are generally all receivables associated with retail sales that have standard terms and are not past due. KU is able to terminate this program at any time without penalty. If there is a significant deterioration in the payment record of the receivables by the retail customers or if KU fails to meet certain covenants regarding the program, the program may terminate at the election of the financial institutions. In this case, payments from retail customers would first be used to repay the financial institutions participating in the program, and would then be available for use by KU.

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As part of the program, KU sold retail accounts receivables to a wholly owned subsidiary KU R. Simultaneously, KU R entered into two separate three-year accounts receivable securitization facilities with two financial institutions and their affiliates whereby KU R can sell, on a revolving basis, an undivided interest in certain of their receivables and receive up to \$50 million from an unrelated third party purchaser. The effective cost of the receivables programs is comparable to KU's lowest cost source of capital, and is based on prime rated commercial paper. KU retains servicing rights of the sold receivables through two separate servicing agreements with the third party purchaser. KU has obtained an opinion from independent legal counsel indicating these transactions qualify as a true sale of receivables. As of December 31, 2002, the outstanding program balance was \$49.3 million. KU is considering unwinding the accounts receivable securitization arrangements involving

KU R during 2003.

The allowance for doubtful accounts associated with the eligible securitized receivables was \$520,000 at December 31, 2002. This allowance is based on historical experience of KU. Each securitization facility contains a fully funded reserve for uncollectible receivables.

RATES AND REGULATION

Following the purchase of Powergen by E.ON, E.ON became a registered holding company under PUHCA. As a result, E.ON, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries are subject to extensive regulation by the SEC under PUHCA with respect to issuances and sales of securities, acquisitions and sales of certain utility properties, and intra-system sales of certain goods and services. In addition, PUHCA generally limits the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company. KU believes that it has adequate authority (including financing authority) under existing SEC orders and regulations to conduct its business. KU will seek additional authorization when necessary.

KU is subject to the jurisdiction of the Kentucky Commission, the Virginia Commission and FERC in virtually all matters related to electric utility regulation, and as such, its accounting is subject to SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. Given KU's competitive position in the market and the status of regulation in the states of Kentucky and Virginia, KU has no plans or intentions to discontinue its application of SFAS No. 71. See Note 3 of KU's Notes to Financial Statements under Item 8.

Kentucky Commission Settlement Order - VDT Costs, ESM and Depreciation

During the first quarter 2001, KU recorded a \$64 million charge for a workforce reduction program. Primary components of the charge were separation benefits, enhanced early retirement benefits, and health care benefits. The result of this workforce reduction was the elimination of approximately 300 positions, accomplished primarily through a voluntary enhanced severance program.

On June 1, 2001, KU filed an application (VDT case) with the Kentucky Commission to create a regulatory asset relating to these first quarter 2001 charges. The application requested permission to amortize these costs over a four-year period. The Kentucky Commission also opened a case to review the new depreciation study and resulting depreciation rates implemented in 2001.

KU reached a settlement in the VDT case as well as the other cases involving depreciation rates and ESM with all intervening parties. The settlement agreement was approved by the Kentucky Commission on December 3, 2001. The order allowed KU to set up a regulatory asset of \$54 million for the workforce reduction costs and begin amortizing these costs over a five year period starting in April 2001. The first quarter 2001 charge of \$64 million represented all employees who had accepted a voluntary enhanced severance program. Some employees rescinded their participation in the voluntary enhanced severance program and, along with the non-recurring charge of \$6.9 million for FERC and Virginia jurisdictions, thereby decreasing the original charge of the regulatory asset from \$64 million to \$54 million. The settlement will also reduce revenues approximately \$11 million through a surcredit on future bills to customers over the same five year period. The surcredit represents stipulated net savings KU is expected to realize from implementation of best practices through the VDT. The agreement also established KU's new depreciation rates in effect December 2001, retroactive to January 1, 2001. The new depreciation rates decreased depreciation expense by \$6.0 million in 2001.

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Environmental Cost Recovery

In June 2000, the Kentucky Commission approved KU's application for a CCN to construct up to four SCR NO_x reduction facilities. The construction and subsequent operation of the SCRs is intended to reduce NO_x emission levels to meet the EPA's mandated NO_x emission level of 0.15 lbs./ Mmbtu by May 2004. In its order, the Kentucky Commission ruled that KU's proposed plan for construction was "reasonable, cost-effective and will not result in the wasteful duplication of facilities". In October 2000, KU filed an application with the Kentucky Commission to amend its Environmental Compliance Plan to reflect the addition of the proposed NO_x reduction technology projects and to amend its Environmental Cost Recovery Tariff to include an overall rate of return on capital investments. Approval of KU's application in April 2001, allowed KU to begin to recover the costs associated with these new projects, subject to Kentucky Commission oversight during normal six-month and two-year reviews.

In August 2002, KU filed an application with the Kentucky Commission to amend its compliance plan to allow recovery of the cost of a new and additional environmental compliance facility. The estimated capital cost of the additional facilities is \$17.3 million. The Kentucky Commission conducted a public hearing on the case on December 20, 2002, final briefs were filed on January 15, 2003, and a final order was issued February 11, 2003. The final order approved recovery of the new environmental compliance facility totaling \$17.3 million. Cost recovery through the environmental surcharge of the approved project will begin with bills rendered in April 2003.

ESM

KU's electric rates are subject to an ESM. The ESM, initially in place for three years beginning in 2000, sets an upper and lower point for rate of return on equity, whereby if KU's rate of return for the calendar year falls within the range of 10.5% to 12.5%, no action is necessary. If earnings are above the upper limit, the excess earnings are shared 40% with ratepayers and 60% with shareholders; if earnings are below the

lower limit, the earnings deficiency is recovered 40% from ratepayers and 60% from shareholders. By order of the Kentucky Commission, rate changes prompted by the ESM filing go into effect in April of each year subject to a balancing adjustment in successive periods. KU made its second ESM filing on March 1, 2002 for the calendar year 2001 reporting period. KU is in the process of refunding \$1 million to customers for the 2001 reporting period. KU estimated that the rate of return will fall below the lower limit, subject to Kentucky Commission approval, for the year ended December 31, 2002. The 2002 financial statements include an accrual to reflect the earnings deficiency of \$13.5 million to be recovered from customers commencing in April 2003.

On November 27, 2002, KU filed a revised ESM tariff which proposed continuance of the existing ESM through December 2005. The Kentucky Commission issued an Order suspending the ESM tariff one day making the effective date January 2, 2003. In addition, the Kentucky Commission is conducting a management audit to review the ESM plan and reassess its reasonableness in 2003. KU and interested parties will have the opportunity to provide recommendations for modification and continuance of the ESM or other forms of alternative or incentive regulation.

DSM

In May 2001, the Kentucky Commission approved a plan that would expand LG&E's current DSM programs into the service territory served by KU. The filing included a rate mechanism that provided for concurrent recovery of DSM costs, provided an incentive for implementing DSM programs, and recovered revenues from lost sales associated with the DSM program based on program planning engineering estimates and post-implementation evaluations.

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FAC

KU employs an FAC mechanism, which allows KU to recover from customers the actual fuel costs associated with retail electric sales. In July 1999, the Kentucky Commission issued a series of orders requiring KU to refund approximately \$10.1 million resulting from reviews of the FAC from November 1994 to October 1998. In August 1999, after a rehearing request by KU, the Kentucky Commission issued a final order that reduced the refund obligation to \$ 6.7 million (\$5.8 million on Kentucky jurisdictional basis) from the original order amount of \$10.1 million. KU implemented the refund from October 1999 through September 2000. Both KU and the KIUC appealed the order. Pending a decision on this appeal, a comprehensive settlement was reached by all parties and approved by the Kentucky Commission on May 17, 2002. Thereunder, KU agreed to credit its fuel clause in the amount of \$954,000 (refund made in June and July 2002), and the parties agreed on a prospective interpretation of the state's fuel adjustment clause regulation to ensure consistent and mutually acceptable application on a going-forward basis.

In December 2002, the Kentucky Commission initiated a two year review of the operation of KU's fuel adjustment clause for the period November 2000 through October 2002. Testimony in the review case was filed on January 20, 2003 and a public hearing was held February 18, 2003. Issues addressed at that time included the establishment of the current base fuel factor to be included in KU's base rates, verification of proper treatment of purchased power costs during unit outages, and compliance with fuel procurement policies and practices.

In January 2003, the Kentucky Commission reviewed the FAC of KU for the six month period ended October 31, 2001. The Kentucky Commission ordered KU to reduce its fuel costs for purposes of calculating its FAC by \$673,000. At issue was the purchase of approximately 102,000 tons of coal from Western Kentucky Energy Corporation, a non-regulated affiliate, for use at KU's Ghent Facility. The Kentucky Commission further ordered that an independent audit be conducted to examine operational and management aspects of KU's fuel procurement functions.

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Kentucky Commission Administrative Case for Affiliate Transactions

In December 1997, the Kentucky Commission opened Administrative Case No. 369 to consider Kentucky Commission policy regarding cost allocations, affiliate transactions and codes of conduct governing the relationship between utilities and their non-utility operations and affiliates. The Kentucky Commission intended to address two major areas in the proceedings: the tools and conditions needed to prevent cost shifting and cross- subsidization between regulated and non-utility operations; and whether a code of conduct should be established to assure that non-utility segments of the holding company are not engaged in practices that could result in unfair competition caused by cost shifting from the non-utility affiliate to the utility. During the period September 1998 to February 2000, the Kentucky Commission issued draft codes of conduct and cost allocation guidelines. In early 2000, the Kentucky General Assembly enacted legislation, House Bill 897, which authorized the Kentucky Commission to require utilities that provide nonregulated activities to keep separate accounts and allocate costs in accordance with procedures established by the Kentucky Commission. In the same bill, the General Assembly set forth provisions to govern a utility's activities related to the sharing of information, databases, and resources between its employees or an affiliate involved in the marketing or the provision of nonregulated activities and its employees or an affiliate involved in the provision of regulated services. The legislation became law in July 2000 and KU has been operating pursuant thereto since that time. On February 14, 2001, the Kentucky Commission published notice of their intent to promulgate new administrative regulation under the auspices of the new law. This effort is still on going.

Kentucky Commission Administrative Case for System Adequacy

On June 19, 2001, Kentucky Governor Paul E. Patton issued Executive Order 2001-771, which directed the Kentucky Commission to review and study issues relating to the need for and development of new electric generating capacity in Kentucky. The issues to be considered included the impact of new power plants on the electric supply grid, facility siting issues, and economic development matters, with the goal of ensuring a continued, reliable source of supply of electricity for the citizens of Kentucky and the continued environmental and economic vitality of Kentucky and its communities. In response to that Executive Order, in July 2001 the Kentucky Commission opened Administrative Case No. 387 to review the adequacy of Kentucky's generation capacity and transmission system. Specifically, the items reviewed were the appropriate level of reliance on purchased power, the appropriate reserve margins to meet existing and future electric demand, the impact of spikes in natural gas prices on electric utility planning strategies, and the adequacy of Kentucky's electric transmission facilities. KU, as a party to this proceeding, filed written testimony and responded to two requests for information. Public hearings were held and in October 2001, KU filed a final brief in the case. In December 2001, the Kentucky Commission issued an order in which it noted that KU is responsibly addressing the long-term supply needs of native load customers and that current reserve margins are appropriate. However, due to the rapid pace of change in the industry, the order also requires KU to provide an annual assessment of supply resources, future demand, reserve margin, and the need for new resources.

Regarding the transmission system, the Kentucky Commission concluded that the transmission system within Kentucky can reliably serve native load and a significant portion of the proposed new unregulated power plants. However, it will not be able to handle the volume of transactions envisioned by FERC without future upgrades, the costs of which should be borne by those for whom the upgrades are required.

The Kentucky Commission pledged to continue to monitor all relevant issues and advocate Kentucky's interests at all opportunities.

FERC SMD NOPR

On July 31, 2002, the FERC issued a NOPR in Docket No. RM01-12-000 which would substantially alter the regulations governing the nation's wholesale electricity markets by establishing a common set of rules -- SMD. The SMD NOPR would require each public utility that owns, operates, or controls interstate transmission facilities to become an Independent Transmission Provider (ITP), belong to an RTO that is an ITP, or contract with an ITP for operation of its transmission assets. It would also establish a standardized congestion management system, real-time and day-ahead energy markets, and a single transmission service for network and point-to-point transmission customers. Review of the proposed rulemaking is underway and a final rule is expected during 2003. While it is expected that the SMD final rule will affect KU revenues and expenses, the specific impact of the rulemaking is not known at this time.

MISO

KU is a member of the MISO, which began commercial operations on February 1, 2002. MISO now has operational control over KU's high-voltage transmission facilities (100 kV and greater), while KU continues to control and operate the lower voltage transmission subject to the terms and conditions of the MISO OATT. As a transmission-owning member of MISO, KU also incurs administrative costs of MISO pursuant to Schedule 10 of the MISO OATT.

MISO also proposed to implement a congestion management system. FERC directed the MISO to coordinate its efforts with FERC's Rulemaking on SMD. On September 24, 2002, the MISO filed new rate schedules designated as Schedules 16 and 17, which provide for the collection of costs incurred by the MISO to establish day-ahead and real-time energy markets. The MISO proposed to recover these costs under Schedules 16 and 17 once service commences. If approved by FERC, these schedules will cause KU to incur additional costs. KU opposes the establishment of Schedules 16 and 17. This effort is still on-going and the ultimate impact of the two schedules, if approved, is not known at this time.

Merger Surcredit

As part of the LG&E Energy merger with KU Energy in 1998, LG&E Energy estimated non-fuel savings over a ten-year period following the merger. Costs to achieve these savings for KU of \$42.3 million were recorded in the second quarter of 1998, \$20.5 million of which was deferred and amortized over a five-year period pursuant to regulatory orders. Primary components of the merger costs were separation benefits, relocation costs, and transaction fees, the majority of which were paid by December 31, 1998. KU expensed the remaining costs associated with the merger (\$21.8 million) in the second quarter of 1998.

In approving the merger, the Kentucky Commission adopted KU's proposal to reduce its retail customers' bills based on one-half of the estimated merger-related savings, net of deferred and amortized amounts, over a five-year period. The surcredit mechanism provides that 50% of the net non-fuel cost savings estimated to be achieved from the merger be provided to ratepayers through a monthly bill credit, and 50% be retained by the Companies, over a five-year period. The surcredit was allocated 53% to KU and 47% to LG&E. In that same order, the Commission required LG&E and KU, after the end of the five-year period, to present a plan for sharing with customers the then-projected non-fuel savings associated with the merger. The Companies submitted this filing on January 13, 2003, proposing to continue to share with customers, on a 50%/50% basis, the estimated fifth-year gross level of non-fuel savings associated with the merger. The filing is currently under review.

Any fuel cost savings are passed to Kentucky customers through the fuel adjustment clause. See FAC above.

Environmental Matters

The Clean Air Act imposed stringent new SO₂ and NO_x emission limits on electric generating units. KU met its Phase I SO₂ requirements primarily through installation of a scrubber on Ghent Unit 1. KU's strategy for Phase II SO₂ reductions, which commenced January 1, 2000, is to use accumulated emissions allowances to delay additional capital expenditures and may also include fuel switching or the installation of additional scrubbers. KU met the NO_x emission requirements of the Act through installation of low-NO_x burner systems. KU's compliance plans are subject to many factors including developments in the emission allowance and fuel markets, future regulatory and legislative initiatives, and advances in clean air control technology. KU will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner.

In September 1998, the EPA announced its final "NO_x SIP Call" rule requiring states to impose significant additional reductions in NO_x emissions by May 2003, in order to mitigate alleged ozone transport impacts on the Northeast region. The Commonwealth of Kentucky is currently in the process of revising its SIP to require reductions in NO_x emissions from coal-fired generating units to the 0.15 lb./Mmbtu level on a system-wide basis. In related proceedings in response to petitions filed by various Northeast states, in December 1999, EPA issued a final rule pursuant to Section 126 of the Clean Air Act directing similar NO_x reductions from a number of specifically targeted generating units including all KU units in the eastern half of Kentucky. Additional petitions currently pending before EPA may potentially result in rules encompassing KU's remaining generating units. As a result of appeals to both rules, the compliance date was extended to May 2004. All KU generating units are subject to the May 2004 compliance date under these NO_x emissions reduction rules.

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KU is currently implementing a plan for adding significant additional NO_x controls to its generating units. Installation of additional NO_x controls will proceed on a phased basis, with installation of controls commencing in late 2000 and continuing through the final compliance date. KU estimates that it will incur total capital costs of approximately \$232 million to reduce its NO_x emissions to the 0.15 lb./Mmbtu level on a company-wide basis. In addition, KU will incur additional operating and maintenance costs in operating new NO_x controls. KU believes its costs in this regard to be comparable to those of similarly situated utilities with like generation assets. KU had anticipated that such capital and operating costs are the type of costs that are eligible for recovery from customers under its environmental surcharge mechanism and believed that a significant portion of such costs could be recovered. In April 2001, the Kentucky Commission granted recovery of these costs for KU.

KU is also monitoring several other air quality issues which may potentially impact coal-fired power plants, including the appeal of the D.C. Circuit's remand of the EPA's revised air quality standards for ozone and particulate matter, measures to implement EPA's regional haze rule, and EPA's December 2000 determination to regulate mercury emissions from power plants.

KU owns or formerly owned several properties that contained past MGP operations. Various contaminants are typically found at such former MGP sites and environmental remediation measures are frequently required. KU has completed the cleanup of a site owned by KU. With respect to other former MGP sites no longer owned by KU, KU is unaware of what, if any, additional exposure or liability it may have.

In October 1999, approximately 38,000 gallons of diesel fuel leaked from a cracked valve in an underground pipeline at KU's E.W. Brown Station. Under the oversight of EPA and state officials, KU commenced immediate spill containment and recovery measures which prevented the spill from reaching the Kentucky River. KU ultimately recovered approximately 34,000 gallons of diesel fuel. In November 1999, the Kentucky Division of Water issued a notice of violation for the incident. KU is currently negotiating with the state in an effort to reach a complete resolution of this matter. KU incurred costs of approximately \$1.8 million and received insurance reimbursement of \$1.2 million. In December 2002, the Department of Justice (DOJ) sent correspondence to KU regarding a potential per-day fine for failure to timely submit a spill control plan and a per-gallon fine for the amount of oil discharged. KU and the DOJ have commenced settlement discussions using existing DOJ settlement guidelines on this matter.

In April 2002, the EPA sent correspondence to KU regarding potential exposure in connection with \$1.5 million in completed remediation costs associated with a transformer scrap-yard. KU believes it is one of the more remote among a number of potentially responsible parties and has entered into settlement discussions with the EPA on this matter.

See Note 11 of KU's Notes to Financial Statements under Item 8 for an additional discussion of environmental issues.

Deferred Income Taxes

KU expects to have adequate levels of taxable income to realize its recorded deferred tax assets. At December 31, 2002, deferred tax assets totaled \$61 million and were principally related to expenses attributable to KU's pension plans and post retirement benefit obligations.

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FUTURE OUTLOOK

Competition and Customer Choice

KU has moved aggressively over the past decade to be positioned for the energy industry's shift to customer choice and a competitive market for energy services. Specifically, KU has taken many steps to prepare for the expected increase in competition in its business, including support for PBR structures, aggressive cost reduction activities; strategic acquisitions, dispositions and growth initiatives; write-offs of previously deferred expenses; an increase in focus on commercial and industrial customers; an increase in employee training; and necessary corporate and business unit realignments.

In December 1997, the Kentucky Commission issued a set of principles which was intended to serve as its guide in consideration of issues relating to industry restructuring. Among the issues addressed by these principles are: consumer protection and benefit, system reliability, universal service, environmental responsibility, cost allocation, stranded costs and codes of conduct. During 1998, the Kentucky Commission and a task force of the Kentucky General Assembly each initiated proceedings, including meetings with representatives of utilities, consumers, state agencies and other groups in Kentucky, to discuss the possible structure and effects of energy industry restructuring in Kentucky.

In November 1999, the task force issued a report to the Governor of Kentucky and a legislative agency recommending no general electric industry restructuring actions during the 2000 legislative session. No general industry restructuring actions have been taken to date by the legislature.

Thus, at the time of this report, neither the Kentucky General Assembly nor the Kentucky Commission has adopted or approved a plan or timetable for retail electric industry competition in Kentucky. The nature or timing of the ultimate legislative or regulatory actions regarding industry restructuring and their impact on KU, which may be significant, cannot currently be predicted.

While many states have moved forward in providing retail choice, many others have not. Some are reconsidering their initiatives and have even delayed implementation.

Virginia has enacted a phase-in of customer choice through the Virginia Electric Restructuring Act. The Virginia Commission is promulgating regulations to govern the various activities required by the Act. KU filed unbundled rates that became effective January 1, 2002. KU was granted a waiver from the Virginia Commission on October 29, 2002, exempting KU from retail choice through December 31, 2004. KU is also seeking a permanent legislative exemption to the Virginia Electric Restructuring Act. The outcome of such legislative initiatives will not be known until mid-2003.

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Exhibit 99(d)

ITEM 8. Financial Statements and Supplementary Data.

INDEX OF ABBREVIATIONS

Capital Corp.	LG&E Capital Corp.
Clean Air Act	The Clean Air Act, as amended in 1990
CCN	Certificate of Public Convenience and Necessity
CT	Combustion Turbines
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
EITF	Emerging Issues Task Force Issue
E.ON	E.ON AG
EPA	U.S. Environmental Protection Agency
ESM	Earnings Sharing Mechanism
F	Fahrenheit
FAC	Fuel Adjustment Clause
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FT and FT-A	Firm Transportation
GSC	Gas Supply Clause
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
KU Energy	KU Energy Corporation
KU R	KU Receivables LLC
kV	Kilovolts
Kva	Kilovolt-ampere
KW	Kilowatts
Kwh	Kilowatt hours
LEM	LG&E Energy Marketing Inc.
LG&E	Louisville Gas and Electric Company

LG&E Energy	LG&E Energy Corp.
LG&E R	LG&E Receivables LLC
LG&E Services	LG&E Energy Services Inc.
Mcf	Thousand Cubic Feet
MGP	Manufactured Gas Plant
MISO	Midwest Independent System Operator
Mmbtu	Million British thermal units
Moody's	Moody's Investor Services, Inc.
Mw	Megawatts
Mwh	Megawatt hours
NNS	No-Notice Service
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen Oxide
OATT	Open Access Transmission Tariff
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PBR	Performance-Based Ratemaking
PJM	Pennsylvania, New Jersey, Maryland Interconnection
Powergen	Powergen Limited (formerly Powergen plc)
PUHCA	Public Utility Holding Company Act of 1935
ROE	Return on Equity

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RTO	Regional Transmission Organization
S&P	Standard & Poor's Rating Services
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission
SERP	Supplemental Employee Retirement Plan
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SMD	Standard Market Design
SO2	Sulfur Dioxide
Tennessee Gas	Tennessee Gas Pipeline Company
Texas Gas	Texas Gas Transmission Corporation
TRA	Tennessee Regulatory Authority
Trimble County	LG&E's Trimble County Unit 1
USWA	United Steelworkers of America

Utility Operations Operations of LG&E and KU VDT Value Delivery Team Process Virginia Commission Virginia State Corporation
Commission Virginia Staff Virginia State Corporation Commission Staff

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Louisville Gas and Electric Company and Subsidiary Consolidated Statements of Income

(Thousands of \$)

Years Ended December 31
2002 2001

OPERATING REVENUES:

Electric	\$ 723,775	\$ 674,492
Gas	267,693	290,775
Provision for rate collections (refunds) (Note 3)	12,267	(720)
Total operating revenues (Note 1)	1,003,735	964,547
OPERATING EXPENSES:		
Fuel for electric generation	194,900	159,231
Power purchased	61,881	49,322
Gas supply expenses	182,108	206,165
Other operation expenses	208,322	167,818
Maintenance	60,210	58,687
Depreciation and amortization (Note 1)	105,906	100,356
Federal and state income taxes (Note 7)	55,035	63,452
Property and other taxes	17,459	17,743
Total operating expenses	885,821	822,774
Net operating income	117,914	141,773
Other income - net (Note 8)	820	2,930
Interest charges	29,805	37,922

Net income	88,929	106,781
Preferred stock dividends	4,246	4,739
Net income available for common stock	\$ 84,683	\$ 102,042

Consolidated Statements of Retained Earnings
(Thousands of \$)

	Years Ended 2002	December 31 2001
Balance January 1	\$393,636	\$314,594
Add net income	88,929	106,781
	482,565	421,375
Deduct: Cash dividends declared on stock:		
5% cumulative preferred	1,075	1,075
Auction rate cumulative preferred	1,702	2,195
\$5.875 cumulative preferred	1,469	1,469
Common	69,000	23,000
	73,246	27,739
Balance December 31	\$409,319	\$393,636

The accompanying notes are an integral part of these consolidated financial statements.

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Louisville Gas and Electric Company and Subsidiary Consolidated Statements of Comprehensive Income

(Thousands of \$)

	Years Ended 2002	December 31 2001
Net income	\$88,929	\$106,781
Cumulative effect of change in accounting principle - Accounting for derivative instruments and hedging activities	-	(5,998)
Losses on derivative instruments and hedging activities (Note 1)	(8,511)	(2,606)
Additional minimum pension liability adjustment (Note 6)	(25,999)	(24,712)
Income tax benefit related to items of other comprehensive income	13,898	13,416
Other comprehensive loss, net of tax	(20,612)	(19,900)
Comprehensive income	\$68,317	\$86,881

The accompanying notes are an integral part of these consolidated financial statements.

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Louisville Gas and Electric Company and Subsidiary Consolidated Balance Sheets

(Thousands of \$)

	December 31	
	2002	2001
ASSETS:		
Utility plant, at original cost (Note 1):		
Electric	\$2,717,187	\$2,598,152
Gas	435,235	409,994

Common	169,577	159,817
	3,321,999	3,167,963
Less: reserve for depreciation	1,463,674	1,381,874
	1,858,325	1,786,089
Construction work in progress	300,986	255,074
	2,159,311	2,041,163
Other property and investments - less reserve of \$63 in 2002 and 2001	764	1,176
Current assets:		
Cash	17,015	2,112
Accounts receivable - less reserve of \$2,125 in 2002 and \$1,575 in 2001	68,440	85,667
Materials and supplies - at average cost:		
Fuel (predominantly coal) (Note 1)	36,600	22,024
Gas stored underground (Note 1)	50,266	46,395
Other	25,651	29,050
Prepayments and other	5,298	4,688
	203,270	189,936
Deferred debits and other assets:		
Unamortized debt expense (Note 1)	6,532	5,921
Regulatory assets (Note 3)	153,446	197,142
Other	37,755	13,016
	197,733	216,079
	\$2,561,078	\$2,448,354

CAPITAL AND LIABILITIES:

Capitalization (see statements of capitalization):

Common equity	\$ 833,141	\$ 838,070
Cumulative preferred stock	95,140	95,140
Long-term debt (Note 9)	328,104	370,704
	1,256,385	1,303,914
Current liabilities:		
Current portion of long-term debt (Note 9)	288,800	246,200
Notes payable (Note 10)	193,053	94,197
Accounts payable	122,771	149,070
Accrued taxes	1,450	20,257
Other	19,536	18,658
	625,610	528,382
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Notes 1 and 7)	313,225	298,143
Investment tax credit, in process of amortization	54,536	58,689
Accumulated provision for pensions and related benefits (Note 6)	224,703	167,526
Regulatory liabilities (Note 3)	52,424	65,349
Other	34,195	26,351
	679,083	616,058
Commitments and contingencies (Note 11)	\$2,561,078	\$2,448,354

The accompanying notes are an integral part of these consolidated financial statements.

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Louisville Gas and Electric Company and Subsidiary Consolidated Statements of Cash Flows

(Thousands of \$)

Years Ended December 31
2002 2001

CASH FLOWS FROM OPERATING ACTIVITIES:

Net income	\$ 88,929	\$ 106,781
Items not requiring cash currently:		
Depreciation and amortization	105,906	100,356
Deferred income taxes - net	11,915	3,021
Investment tax credit - net	(4,153)	(4,290)

Other	37,260	(528)
Change in certain net current assets:		
Accounts receivable	(3,973)	43,185
Materials and supplies	(15,048)	(2,018)
Accounts payable	(26,299)	14,678
Accrued taxes	(18,807)	12,184
Prepayments and other	321	(10,500)
Sale of accounts receivable (Note 1)	21,200	42,000
Other	15,130	(17,806)
Net cash flows from operating activities	212,381	287,063
CASH FLOWS FROM INVESTING ACTIVITIES:		
Purchases of securities	-	-
Proceeds from sales of securities	412	4,237
Construction expenditures	(220,416)	(252,958)
Net cash flows from investing activities	(220,004)	(248,721)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Short-term borrowings and repayments	98,856	(20,392)
Issuance of pollution control bonds	158,635	9,662
Retirement of first mortgage bonds and pollution control bonds	(161,665)	-
Additional paid-in capital	-	-
Payment of dividends	(73,300)	(27,995)
Net cash flows from financing activities	22,526	(38,725)
Change in cash and temporary cash investments	14,903	(383)
Cash and temporary cash investments at beginning of year	2,112	2,495
Cash and temporary cash investments at end of year	\$ 17,015	\$ 2,112
Supplemental disclosures of cash flow information:		
Cash paid during the year for:		
Income taxes	\$51,540	\$ 35,546
Interest on borrowed money	25,673	30,989

The accompanying notes are an integral part of these consolidated financial statements.

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Louisville Gas and Electric Company and Subsidiary Consolidated Statements of Capitalization

(Thousands of \$)

	December 31	
	2002	2001
COMMON EQUITY:		
Common stock, without par value -		
Authorized 75,000,000 shares,		
outstanding 21,294,223 shares	\$ 425,170	\$ 425,170
Common stock expense	(836)	(836)
Additional paid-in capital	40,000	40,000
Accumulated other comprehensive income	(40,512)	(19,900)
Retained earnings	409,319	393,636
	833,141	838,070
CUMULATIVE PREFERRED STOCK:		
	Shares	Current
	Outstanding	Redemption Price
\$25 par value,		
1,720,000 shares		
authorized - 5% series	860,287	\$28.00
Without par value,		
6,750,000 shares authorized -		
Auction rate	500,000	100.00
\$5.875 series	250,000	101.18
Preferred stock expense		(1,367)
		(1,367)
		95,140
		95,140
LONG-TERM DEBT (Note 9):		
First mortgage bonds -		
Series due August 15, 2003, 6%	42,600	42,600
Pollution control series:		

R due November 1, 2020, 6.55 %	-	41,665
S due September 1, 2017, variable %	31,000	31,000
T due September 1, 2017, variable %	60,000	60,000
U due August 15, 2013, variable %	35,200	35,200
V due August 15, 2019, 5.625%	102,000	102,000
W due October 15, 2020, 5.45%	26,000	26,000
X due April 15, 2023, 5.90%	40,000	40,000
Y due May 1, 2027, variable %	25,000	25,000
Z due August 1, 2030, variable %	83,335	83,335
AA due September 1, 2027, variable %	10,104	10,104
BB due September 1, 2026, variable %	22,500	-
CC due September 1, 2026, variable %	27,500	-
DD due November 1, 2027, variable %	35,000	-
EE due November 1, 2027, variable %	35,000	-
FF due October 1, 2032, variable %	41,665	-
Total first mortgage bonds	616,904	496,904
Pollution control bonds (unsecured) -		
Series due September 1, 2026, variable %	-	22,500
Series due September 1, 2026, variable %	-	27,500
Series due November 1, 2027, variable %	-	35,000
Series due November 1, 2027, variable %	-	35,000
Total unsecured pollution control bonds	-	120,000
Total bonds outstanding	616,904	616,904
Less current portion of long-term debt	288,800	246,200
Long-term debt	328,104	370,704
Total capitalization	\$1,256,385	\$1,303,914

The accompanying notes are an integral part of these consolidated financial statements.

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Louisville Gas and Electric Company and Subsidiary

Notes to Consolidated Financial Statements

Note 1 - Summary of Significant Accounting Policies

LG&E, a subsidiary of LG&E Energy and an indirect subsidiary of Powergen and E.ON, is a regulated public utility engaged in the generation, transmission, distribution, and sale of electric energy and the storage, distribution, and sale of natural gas in Louisville and adjacent areas in Kentucky. LG&E Energy is an exempt public utility holding company with wholly owned subsidiaries including LG&E, KU, Capital Corp., LEM, and LG&E Services. All of LG&E's Common Stock is held by LG&E Energy. LG&E has one wholly owned consolidated subsidiary, LG&E R.

On December 11, 2000, LG&E Energy was acquired by Powergen. On July 1, 2002, E.ON, a German company, completed its acquisition of Powergen plc (now Powergen Limited). E.ON had announced its pre-conditional cash offer of 5.1 billion pounds sterling (\$7.3 billion) for Powergen on April 9, 2001. E.ON and Powergen are registered public utility holding companies under PUHCA. No costs associated with these acquisitions nor any of the effects of purchase accounting have been reflected in the financial statements of LG&E.

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2002 presentation with no impact on the balance sheet totals or previously reported income.

Utility Plant. LG&E's utility plant is stated at original cost, which includes payroll-related costs such as taxes, fringe benefits, and administrative and general costs. Construction work in progress has been included in the rate base for determining retail customer rates. LG&E has not recorded any allowance for funds used during construction.

The cost of plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost, plus removal expense less salvage value, is charged to the reserve for depreciation. When complete operating units are disposed of, appropriate adjustments are made to the reserve for depreciation and gains and losses, if any, are recognized.

Depreciation and Amortization. Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. Pursuant to a final order of the Kentucky Commission dated December 3, 2001, LG&E implemented new depreciation rates effective January 1, 2001. The amounts provided were approximately 3.1% in 2002 (2.9% electric, 2.8% gas and 6.6% common) and 3.0% for 2001 (2.9% electric, 2.9% gas and 5.7% common), of average depreciable plant. Of the amount provided for depreciation, at December 31, 2002 and 2001, respectively, approximately 0.4 % electric, 0.9 % gas and 0.04% common were related to the retirement, removal and disposal costs of long lived assets.

Fuel Inventory. Fuel inventories of \$36.6 million and \$22.0 million at December 31, 2002, and 2001, respectively, are included in Fuel in the balance sheet. The inventory is accounted for using the average-cost method.

Gas Stored Underground. Gas inventories of \$50.3 million and \$46.4 million at December 31, 2002, and 2001, respectively, are included in gas stored underground in the balance sheet. The inventory is accounted for using the average-cost method.

Financial Instruments. LG&E uses over-the-counter interest-rate swap agreements to hedge its exposure to fluctuations in the interest rates it pays on variable-rate debt. Gains and losses on interest-rate swaps used to hedge interest rate risk are reflected in other comprehensive income. See Note 4- Financial Instruments.

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Unamortized Debt Expense. Debt expense is capitalized in deferred debits and amortized over the lives of the related bond issues, consistent with regulatory practices.

Deferred Income Taxes. Deferred income taxes are recognized at currently enacted tax rates for all material temporary differences between the financial reporting and income tax basis of assets and liabilities.

Investment Tax Credits. Investment tax credits resulted from provisions of the tax law that permitted a reduction of LG&E's tax liability based on credits for certain construction expenditures. Deferred investment tax credits are being amortized to income over the estimated lives of the related property that gave rise to the credits.

Revenue Recognition. Revenues are recorded based on service rendered to customers through month-end. LG&E accrues an estimate for unbilled revenues from each meter reading date to the end of the accounting period. The unbilled revenue estimates included in accounts receivable were approximately \$40.7 million and \$37.3 million, at December 31, 2002 and 2001, respectively. See Note 3, Rates and Regulatory Matters. LG&E recorded electric revenues that resulted from sales to a related party, KU, of \$46.5 million and \$28.5 million for years ended December 31, 2002 and 2001, respectively.

With the adoption of EITF 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, revenues on the income statement are shown net of cost associated with trading activities. As a result LG&E has netted the power purchased expense for trading activities against operating revenue for all years presented.

Fuel and Gas Costs. The cost of fuel for electric generation is charged to expense as used, and the cost of gas supply is charged to expense as delivered to the distribution system. LG&E implemented a Kentucky Commission-approved performance-based ratemaking mechanism related to gas procurement and off-system gas sales activity. See Note 3, Rates and Regulatory Matters.

Management's Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent items at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. See Note 11, Commitments and Contingencies, for a further discussion.

Accounts Receivable Securitization. SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, revises the standards for accounting for securitizations and other transfers of financial assets and collateral and requires certain disclosures, and provides accounting and reporting standards for transfers and servicing of financial assets and extinguishments of liabilities. SFAS No. 140 was adopted in the first quarter of 2001, when LG&E entered into an accounts receivable securitization transaction.

On February 6, 2001, LG&E implemented an accounts receivable securitization program. The purpose of this program is to enable LG&E to accelerate the receipt of cash from the collection of retail accounts receivable, thereby reducing dependence upon more costly sources of working capital. The securitization program allows for a percentage of eligible receivables to be sold. Eligible receivables are generally all receivables associated with retail sales that have standard terms and are not past due. LG&E is able to terminate this program at any time without penalty. If there is a significant deterioration in the payment record of the receivables by the retail customers or if LG&E fails to meet certain covenants regarding the program, the program may terminate at the election of the financial institutions. In this case, payments from retail customers would first be used to repay the financial institutions participating in the program, and would then be available for use by LG&E.

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As part of the program, LG&E sold retail accounts receivables to a wholly owned subsidiary, LG&E R. Simultaneously, LG&E R entered into two separate three-year accounts receivable securitization facilities with two financial institutions and their affiliates whereby LG&E R can sell, on a revolving basis, an undivided interest in certain of its receivables and receive up to \$75 million from an unrelated third party purchaser. The effective cost of the receivables programs is comparable to LG&E's lowest cost source of capital, and is based on prime rated commercial paper. LG&E retains servicing rights of the sold receivables through two separate servicing agreements with the third party purchaser. LG&E has obtained an opinion from independent legal counsel indicating these transactions qualify as true sale of receivables. As of December 31, 2002, the outstanding program balance was \$63.2 million. LG&E is considering unwinding its accounts receivable securitization

arrangements involving LG&E R during 2003.

The allowance for doubtful accounts associated with the eligible securitized receivables was \$2.125 million at December 31, 2002. This allowance is based on historical experience of LG&E. Each securitization facility contains a fully funded reserve for uncollectible receivables.

New Accounting Pronouncements.

SFAS No. 143, Accounting for Asset Retirement Obligations was issued in 2001. SFAS No. 143 establishes accounting and reporting standards for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs.

The effective implementation date for SFAS No. 143 is January 1, 2003. Management has calculated the impact of SFAS No. 143 and the recently released FERC NOPR No. RM02-7, Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations. As of January 1, 2003, LG&E recorded asset retirement obligation (ARO) assets in the amount of \$4.6 million and liabilities in the amount of \$9.3 million. LG&E also recorded a cumulative effect adjustment in the amount of \$5.3 million to reflect the accumulated depreciation and accretion of ARO assets at the transition date less amounts previously accrued under regulatory depreciation. LG&E recorded offsetting regulatory assets of \$5.3 million, pursuant to regulatory treatment prescribed under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. Also pursuant to SFAS No. 71, LG&E recorded regulatory liabilities in the amount of \$60,000 offsetting removal costs previously accrued under regulatory accounting in excess of amounts allowed under SFAS No. 143.

LG&E also expects to record ARO accretion expense of approximately \$617,000, ARO depreciation expense of approximately \$117,000 and an offsetting regulatory credit in the income statement of approximately \$734,000 in 2003, pursuant to regulatory treatment prescribed under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. The accretion, depreciation and regulatory credit will be annual adjustments. SFAS No. 143 will have no impact on the results of the operation of LG&E.

LG&E asset retirement obligations are primarily related to the final retirement of generating units. LG&E transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under SFAS No. 143, no material asset retirement obligations will be recorded for transmission and distribution assets.

LG&E adopted EITF No. 98-10, Accounting for Energy Trading and Risk Management Activities, effective January 1, 1999. This pronouncement required that energy trading contracts be marked to market on the balance sheet, with the gains and losses shown net in the income statement.

The EITF clarified accounting standards related to energy trading activities under EITF Issue 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in

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Energy Trading and Risk Management Activities. EITF No. 02-03 established the following:

- Rescinded EITF No. 98-10,
- Contracts that do not meet the definition of a derivative under SFAS No.133 should not be marked to fair market value, and
- Revenues should be shown in the income statement net of costs associated with trading activities, whether or not the trades are physically settled.

With the rescission of EITF No. 98-10, energy trading contracts that do not also meet the definition of a derivative under SFAS No. 133 must be accounted for as executory contracts. Contracts previously recorded at fair value under EITF No. 98-10 that are not also derivatives under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, must be restated to historical cost through a cumulative effect adjustment. The rescission of this standard had no impact on financial position or results of operations of LG&E since all contracts marked to market under EITF No. 98-10 are also within the scope of SFAS No. 133.

As a result of EITF No. 02-03, LG&E has netted the power purchased expense for trading activities against electric operating revenue to reflect this accounting change. LG&E applied this guidance to all prior periods, which had no impact on previously reported net income or common equity.

	2002	2001
Gross electric operating revenues	\$746,224	\$706,645
Less costs reclassified from power purchased	22,449	32,153
Net electric operating revenues reported	\$723,775	\$674,492
Gross power purchased	\$ 84,330	\$ 81,475
Less costs reclassified to revenues	22,449	32,153
Net power purchased reported	\$ 61,881	\$ 49,332

In January 2003, the Financial Accounting Standards Board issued Financial Accounting Standards Board Interpretation No. 46, Consolidation

of Variable Interest Entities, an Interpretation of ARB No. 51 (FIN 46). FIN 46 requires certain variable interest entities to be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. FIN 46 is effective immediately for all new variable interest entities created or acquired after January 31, 2003. For variable interest entities created or acquired prior to February 1, 2003, the provisions of FIN 46 must be applied for the first interim or annual period beginning after June 15, 2003. LG&E does not expect the adoption of this standard to have any impact on the financial position or results of operations.

Note 2 - Mergers and Acquisitions

On July 1, 2002, E.ON completed its acquisition of Powergen, including LG&E Energy, for approximately 5.1 billion pounds sterling (\$7.3 billion). As a result of the acquisition, LG&E Energy became a wholly owned subsidiary (through Powergen) of E.ON and, as a result, LG&E also became an indirect subsidiary of E.ON. LG&E has continued its separate identity and serves customers in Kentucky under its existing name. The preferred stock and debt securities of LG&E were not affected by this transaction and the utilities continue to file SEC reports. Following the acquisition, E.ON became, and Powergen remained, a registered holding company under PUHCA. LG&E, as a subsidiary of a registered holding company, is subject to additional regulations under PUHCA. As contemplated in their regulatory filings in connection with the E.ON acquisition, E.ON, Powergen and LG&E Energy completed an administrative reorganization to move the LG&E Energy group from an indirect Powergen subsidiary to an indirect E.ON subsidiary. This reorganization was effective in March 2003.

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LG&E Energy and KU Energy merged on May 4, 1998, with LG&E Energy as the surviving corporation. Management accounted for the merger as a pooling of interests and as a tax-free reorganization under the Internal Revenue Code. Following the acquisition, LG&E has continued to maintain its separate corporate identity and serve customers in Kentucky under its present name.

Note 3 - Rates and Regulatory Matters

Accounting for the regulated utility business conforms with generally accepted accounting principles as applied to regulated public utilities and as prescribed by FERC and the Kentucky Commission. LG&E is subject to SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, under which certain costs that would otherwise be charged to expense are deferred as regulatory assets based on expected recovery from customers in future rates. Likewise, certain credits that would otherwise be reflected as income are deferred as regulatory liabilities based on expected return to customers in future rates. LG&E's current or expected recovery of deferred costs and expected return of deferred credits is generally based on specific ratemaking decisions or precedent for each item. The following regulatory assets and liabilities were included in LG&E's balance sheets as of December 31 (in thousands of \$):

	2002	2001
VDT Costs	\$ 98,044	\$127,529
Gas supply adjustments due from customers	13,714	30,135
Unamortized loss on bonds	18,843	17,902
ESM provision	12,500	-
LGE/KU merger costs	1,815	5,444
Manufactured gas sites	1,757	2,062
One utility costs	954	3,643
Other	5,819	10,427
Total regulatory assets	153,446	197,142
Deferred income taxes - net	(45,536)	(48,703)
Gas supply adjustments due to customers	(3,154)	(15,702)
Other	(3,734)	(944)
Total regulatory liabilities	(52,424)	(65,349)
Regulatory assets - net	\$101,022	\$131,793

Kentucky Commission Settlement - VDT Costs. During the first quarter 2001, LG&E recorded a \$144 million charge for a workforce reduction program. Primary components of the charge were separation benefits, enhanced early retirement benefits, and health care benefits. The result of this workforce reduction was the elimination of approximately 700 positions, accomplished primarily through a voluntary enhanced severance program.

On June 1, 2001, LG&E filed an application (VDT case) with the Kentucky Commission to create a regulatory asset relating to these first quarter 2001 charges. The application requested permission to amortize these costs over a four-year period. The Kentucky Commission also opened a case to review a new depreciation study and resulting depreciation rates implemented in 2001.

LG&E reached a settlement in the VDT case as well as the other cases involving depreciation rates and ESM with all intervening parties. The settlement agreement was approved by the Kentucky Commission on December 3, 2001. The order allowed LG&E to set up a regulatory asset of \$141 million for the workforce reduction costs and begin amortizing these costs over a five year period starting in April 2001. The first quarter 2001 charge of \$144 million represented all employees who had accepted a voluntary enhanced severance program. Some employees rescinded their participation in the voluntary enhanced severance program, thereby decreasing the

original charge from \$144 million to \$141 million. The settlement will also reduce revenues approximately \$26 million through a surcredit on future bills to customers over the same five year period. The surcredit represents net savings stipulated by LG&E. The agreement also established LG&E's new depreciation rates in effect December 2001, retroactive to January 1, 2001. The new depreciation rates decreased depreciation expense by \$5.6 million in 2001.

PUHCA. LG&E Energy was purchased by Powergen on December 11, 2000. Effective July 1, 2002, Powergen was acquired by E.ON, which became a registered holding company under PUHCA. As a result, E.ON, its utility subsidiaries, including LG&E, and certain of its non-utility subsidiaries are subject to extensive regulation by the SEC under PUHCA with respect to issuances and sales of securities, acquisitions and sales of certain utility properties, and intra-system sales of certain goods and services. In addition, PUHCA generally limits the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company. LG&E believes that it has adequate authority (including financing authority) under existing SEC orders and regulations to conduct its business. LG&E will seek additional authorization when necessary.

Environmental Cost Recovery. In June 2000, the Kentucky Commission approved LG&E's application for a CCN to construct up to three SCR NOx reduction facilities. The construction and subsequent operation of the SCRs is intended to reduce NOx emission levels to meet the EPA's mandated NOx emission level of 0.15 lbs./ Mmbtu by May 2004. In its order, the Kentucky Commission ruled that LG&E's proposed plan for construction was "reasonable, cost-effective and will not result in the wasteful duplication of facilities." In October 2000, LG&E filed an application with the Kentucky Commission to amend its Environmental Compliance Plan to reflect the addition of the proposed NOx reduction technology projects and to amend its ECR Tariff to include an overall rate of return on capital investments. Approval of LG&E's application in April 2001 allowed LG&E to begin to recover the costs associated with these new projects, subject to Kentucky Commission oversight during normal six-month and two-year reviews.

In August 2002, LG&E filed an application with the Kentucky Commission to amend its compliance plan to allow recovery of the cost of new and additional environmental compliance facilities. The estimated capital cost of the additional facilities is \$71.1 million. The Kentucky Commission conducted a public hearing on the case on December 20, 2002, final briefs were filed on January 15, 2003, and a final order was issued February 11, 2003. The final order approved recovery of four new environmental compliance facilities totaling \$43.1 million. A fifth project, expansion of the land fill facility at the Mill Creek Station, was denied without prejudice with an invitation to reapply for recovery when required construction permits are approved. Cost recovery through the environmental surcharge of the four approved projects will begin with the bills rendered in April 2003.

ESM. LG&E's electric rates are subject to an ESM. The ESM, initially in place for three years beginning in 2000, sets an upper and lower point for rate of return on equity, whereby if LG&E's rate of return for the calendar year falls within the range of 10.5% to 12.5%, no action is necessary. If earnings are above the upper limit, the excess earnings are shared 40% with ratepayers and 60% with shareholders; if earnings are below the lower limit, the earnings deficiency is recovered 40% from ratepayers and 60% from shareholders. By order of the Kentucky Commission, rate changes prompted by the ESM filing go into effect in April of each year subject to a balancing adjustment in successive periods. LG&E made its second ESM filing on March 1, 2002 for the calendar year 2001 reporting period. LG&E is in the process of refunding \$441,000 to customers for the 2001 reporting period. LG&E estimated that the rate of return will fall below the lower limit, subject to Kentucky Commission approval, for the year ended December 31, 2002. The 2002 financial statements include an accrual to reflect the earnings deficiency of \$12.5 million to be recovered from customers commencing in April 2003.

On November 27, 2002, LG&E filed a revised ESM tariff which proposed continuance of the existing ESM through December 2005. The Kentucky Commission issued an Order suspending the ESM tariff one day making the

effective date January 2, 2003. In addition, the Kentucky Commission is conducting a management audit to review the ESM plan and reassess its reasonableness in 2003. LG&E and interested parties will have the opportunity to provide recommendations for modification and continuance of the ESM or other forms of alternative or incentive regulation.

DSM. LG&E's rates contain a DSM provision. The provision includes a rate mechanism that provides concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. This program had allowed LG&E to recover revenues from lost sales associated with the DSM program. In May 2001, the Kentucky Commission approved LG&E's plan to continue DSM programs. This filing called for the expansion of the DSM programs into the service territory served by KU and proposed a mechanism to recover revenues from lost sales associated with DSM programs based on program planning engineering estimates and post-implementation evaluation.

Gas PBR. Since November 1, 1997, LG&E has operated under an experimental PBR mechanism related to its gas procurement activities. For each of the last five years, LG&E's rates have been adjusted to recover its portion of the savings (or expenses) incurred during each of the five 12-month periods beginning November 1 and ending October 31. Since its implementation on November 1, 1997, through October 31, 2001, LG&E has achieved \$38.1 million in savings. Of the total savings, LG&E has retained \$16.5 million, and the remaining portion of \$21.6 million has been distributed to customers. In December 2000, LG&E filed an application reporting on the operation of the experimental PBR and requested the Kentucky Commission to extend the PBR as a result of the benefits provided to both LG&E and its customers during the experimental period. Following the discovery and hearing process, the Kentucky Commission issued an order effective November 1, 2001, extending the experimental PBR program for an additional four years, and making other modifications, including changes to the sharing levels

applicable to savings or expenses incurred under the PBR. Specifically, the Kentucky Commission modified the savings mechanism to a 25%/75% Company/Customer sharing for all savings (and expenses) up to 4.5% of the benchmarked gas costs. Savings (and expenses) in excess of 4.5% of the benchmarked gas costs are shared at a 50%/50% level.

FAC. Prior to implementation of the electric PBR in July 1999, and following its termination in March 2000, LG&E employed an FAC mechanism, which under Kentucky law allowed LG&E to recover from customers the actual fuel costs associated with retail electric sales. In February 1999, LG&E received orders from the Kentucky Commission requiring a refund to retail electric customers of approximately \$3.9 million resulting from reviews of the FAC from November 1994, through April 1998. While legal challenges to the Kentucky Commission order were pending, a comprehensive settlement was reached by all parties and approved by the Kentucky Commission on May 17, 2002. Thereunder, LG&E agreed to credit its fuel clause in the amount of \$720,000 (such credit provided over the course of June and July 2002), and the parties agreed on a prospective interpretation of the state's FAC regulation to ensure consistent and mutually acceptable application on a going-forward basis.

In December 2002, the Kentucky Commission initiated a two year review of the operation of LG&E's FAC for the period November 2000 through October 2002. Testimony in the review case was filed on January 20, 2003 and a public hearing was held February 18, 2003. Issues addressed at that time included the establishment of the current base fuel factor to be included in LG&E's base rates, verification of proper treatment of purchased power costs during unit outages, and compliance with fuel procurement policies and practices.

Gas Rate Case. In March 2000, LG&E filed an application with the Kentucky Commission requesting an adjustment in LG&E's gas rates. In September 2000, the Kentucky Commission granted LG&E an annual increase in its base gas revenues of \$20.2 million effective September 28, 2000. The Kentucky Commission authorized a return on equity of 11.25%. The Kentucky Commission approved LG&E's proposal for a weather normalization billing adjustment mechanism that will normalize the effect of weather on base gas revenues from gas sales.

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Wholesale Natural Gas Prices. On September 12, 2000, the Kentucky Commission issued an order establishing Administrative Case No. 384 - "An Investigation of Increasing Wholesale Natural Gas Prices and the Impacts of such Increase on the Retail Customers Served by Kentucky's Jurisdictional Natural Gas Distribution Companies". The impetus for this administrative proceeding was the escalation of wholesale natural gas prices during the summer of 2000.

The Kentucky Commission directed Kentucky's natural gas distribution companies, including LG&E, to file selected information regarding the individual companies' natural gas purchasing practices, expectations for the then-approaching winter heating season of 2000-2001, and potential actions which these companies might take to mitigate price volatility. On July 17, 2001, the Kentucky Commission issued an order encouraging the natural gas distribution companies in Kentucky to take various actions, among them to propose a natural gas hedge plan, consider performance-based ratemaking mechanisms, and to increase the use of storage.

In April 2002, in Case No. 2002-00136, LG&E proposed a hedging plan for the 2002/2003 winter heating season with three alternatives, the first two using a combination of storage and financial hedge instruments and the third relying upon storage alone. LG&E and the Attorney General, who represents Kentucky consumers, entered into a settlement which selected the third option. In August 2002, the Kentucky Commission approved the plan contemplated in the settlement. The Kentucky Commission validated the effectiveness of storage to mitigate potentially high winter gas prices by approving this natural gas hedging plan.

The Kentucky Commission also decided in Administrative Case No. 384 to engage a consultant to conduct a forward-looking audit of the gas procurement and supply procedures of Kentucky's largest natural gas distribution companies. The Kentucky Commission completed its audit in late 2002. The audit recognized LG&E as "efficient and effective [in the] procurement and management of significant quantities of natural gas supplies." The auditors also recognized that "the Company's residential gas prices have long been below averages for the U. S. and for the Commonwealth of Kentucky" which "demonstrates [LG&E's] effectiveness in [the] procurement and management of natural gas supplies." The audit also stated that the "Company's very impressive record in keeping its rates down provides sound evidence on the excellent job done in the area of gas supply procurement and management."

Kentucky Commission Administrative Case for Affiliate Transactions. In December 1997, the Kentucky Commission opened Administrative Case No. 369 to consider Kentucky Commission policy regarding cost allocations, affiliate transactions and codes of conduct governing the relationship between utilities and their non-utility operations and affiliates. The Kentucky Commission intended to address two major areas in the proceedings:

the tools and conditions needed to prevent cost shifting and cross- subsidization between regulated and non-utility operations; and whether a code of conduct should be established to assure that non-utility segments of the holding company are not engaged in practices that could result in unfair competition caused by cost shifting from the non-utility affiliate to the utility. During the period September 1998 to February 2000, the Kentucky Commission issued draft codes of conduct and cost allocation guidelines. In early 2000, the Kentucky General Assembly enacted legislation, House Bill 897, which authorized the Kentucky Commission to require utilities that provide nonregulated activities to keep separate accounts and allocate costs in accordance with procedures established by the Kentucky Commission. In the same bill, the General Assembly set forth provisions to govern a utility's activities related to the sharing of information, databases, and resources between its employees or an affiliate involved in the marketing or the provision of nonregulated activities and its employees or an affiliate involved in the provision of regulated services. The legislation became law in July 2000 and LG&E has been operating pursuant thereto since that time. On February 14, 2001, the Kentucky Commission published notice of its intent to promulgate new administrative regulations under the auspices of this new law. This effort is still on going.

which directed the Kentucky Commission to review and study issues relating to the need for and development of new electric generating capacity in Kentucky. The issues to be considered included the impact of new power plants on the electric supply grid, facility citing issues, and economic development matters, with the goal of ensuring a continued, reliable source of supply of electricity for the citizens of Kentucky and the continued environmental and economic vitality of Kentucky and its communities. In response to that Executive Order, in July 2001 the Kentucky Commission opened Administrative Case No. 387 to review the adequacy of Kentucky's generation capacity and transmission system. Specifically, the items reviewed were the appropriate level of reliance on purchased power, the appropriate reserve margins to meet existing and future electric demand, the impact of spikes in natural gas prices on electric utility planning strategies, and the adequacy of Kentucky's electric transmission facilities. LG&E, as a party to this proceeding, filed written testimony and responded to two requests for information. Public hearings were held and in October 2001, LG&E filed a final brief in the case. In December 2001, the Kentucky Commission issued an order in which it noted that LG&E is responsibly addressing the long-term supply needs of native load customers and that current reserve margins are appropriate. However, due to the rapid pace of change in the industry, the order also requires LG&E to provide an annual assessment of supply resources, future demand, reserve margin, and the need for new resources.

Regarding the transmission system, the Kentucky Commission concluded that the transmission system within Kentucky can reliably serve native load and a significant portion of the proposed new unregulated power plants. However, it will not be able to handle the volume of transactions envisioned by FERC without future upgrades, the costs of which should be borne by those for whom the upgrades are required.

The Kentucky Commission pledged to continue to monitor all relevant issues and advocate Kentucky's interests at all opportunities.

FERC SMD NOPR. On July 31, 2002, FERC issued a NOPR in Docket No. RM01-12-000 which would substantially alter the regulations governing the nation's wholesale electricity markets by establishing a common set of rules -- SMD. The SMD NOPR would require each public utility that owns, operates, or controls interstate transmission facilities to become an Independent Transmission Provider (ITP), belong to an RTO that is an ITP, or contract with an ITP for operation of its transmission assets. It would also establish a standardized congestion management system, real-time and day-ahead energy markets, and a single transmission service for network and point-to-point transmission customers. Review of the proposed rulemaking is underway and a final rule is expected during 2003. While it is expected that the SMD final rule will affect LG&E revenues and expenses, the specific impact of the rulemaking is not known at this time.

MISO. LG&E is a member of the MISO, which began commercial operations on February 1, 2002. MISO now has operational control over LG&E's high-voltage transmission facilities (100 kV and greater), while LG&E continues to control and operate the lower voltage transmission subject to the terms and conditions of the MISO OATT. As a transmission-owning member of MISO, LG&E also incurs administrative costs of MISO pursuant to Schedule 10 of the MISO OATT.

MISO also proposed to implement a congestion management system. FERC directed the MISO to coordinate its efforts with FERC's Rulemaking on SMD. On September 24, 2002, the MISO filed new rate schedules designated as Schedules 16 and 17, which provide for the collection of costs incurred by the MISO to establish day-ahead and real-time energy markets. The MISO proposed to recover these costs under Schedules 16 and 17 once service commences. If approved by FERC, these schedules will cause LG&E to incur additional costs. LG&E opposes the establishment of Schedules 16 and 17. This effort is still on-going and the ultimate impact of the two schedules, if approved, is not known at this time.

ARO. In 2003, LG&E expects to record approximately \$6.0 million in regulatory assets and approximately \$60,000 in regulatory liabilities related to SFAS No. 143, Accounting for Asset Retirement Obligations.

Merger Surcredit. As part of the LG&E Energy merger with KU Energy in 1998, LG&E Energy estimated non-fuel savings over a ten-year period following the merger. Costs to achieve these savings for LG&E of \$50.2 million were recorded in the second quarter of 1998, \$18.1 million of which was deferred and amortized over a five-year period pursuant to regulatory orders. Primary components of the merger costs were separation benefits, relocation costs, and transaction fees, the majority of which were paid by December 31, 1998. LG&E expensed the remaining costs associated with the merger (\$32.1 million) in the second quarter of 1998.

In approving the merger, the Kentucky Commission adopted LG&E's proposal to reduce its retail customers' bills based on one-half of the estimated merger-related savings, net of deferred and amortized amounts, over a five-year period. The surcredit mechanism provides that 50% of the net non-fuel cost savings estimated to be achieved from the merger be provided to ratepayers through a monthly bill credit, and 50% be retained by the Companies, over a five-year period. The surcredit was allocated 53% to KU and 47% to LG&E. In that same order, the Commission required LG&E and KU, after the end of the five-year period, to present a plan for sharing with customers the then-projected non-fuel savings associated with the merger. The Companies submitted this filing on January 13, 2003, proposing to continue to share with customers, on a 50%/50% basis, the estimated fifth-year gross level of non-fuel savings associated with the merger. The filing is currently under review.

Any fuel cost savings are passed to Kentucky customers through the fuel adjustment clause. See FAC above.

Note 4 - Financial Instruments

The cost and estimated fair values of LG&E's non-trading financial instruments as of December 31, 2002, and 2001 follow (in thousands of \$):

	2002		2001	
	Cost	Fair Value	Cost	Fair Value
Preferred stock subject to mandatory redemption	\$ 25,000	\$ 25,188	\$ 25,000	\$ 25,125
Long-term debt (including current portion)	616,904	623,325	616,904	620,504

Interest-rate swaps - (17,115) - (8,604)

All of the above valuations reflect prices quoted by exchanges except for the swaps. The fair values of the swaps reflect price quotes from dealers or amounts calculated using accepted pricing models.

Interest Rate Swaps. LG&E uses interest rate swaps to hedge exposure to market fluctuations in certain of its debt instruments. Pursuant to policy, use of these financial instruments is intended to mitigate risk and earnings volatility and is not speculative in nature. Management has designated all of the interest rate swaps as hedge instruments. Financial instruments designated as cash flow hedges have resulting gains and losses recorded within other comprehensive income and stockholders' equity. To the extent a financial instrument or the underlying item being hedged is prematurely terminated or the hedge becomes ineffective, the resulting gains or losses are reclassified from other comprehensive income to net income. Financial instruments designated as fair value hedges are periodically marked to market with the resulting gains and losses recorded directly into net income to correspond with income or expense recognized from changes in market value of the items being hedged.

As of December 31, 2002 and 2001, LG&E was party to various interest rate swap agreements with aggregate notional amounts of \$117.3 million. Under these swap agreements, LG&E paid fixed rates averaging 5.13% and received variable rates based on the Bond Market Association's municipal swap index

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averaging 1.52% and 1.61% at December 31, 2002 and 2001, respectively. The swap agreements in effect at December 31, 2002 have been designated as cash flow hedges and mature on dates ranging from 2003 to 2020. The hedges have been deemed to be fully effective resulting in a pretax loss of \$8.5 million for 2002, recorded in other comprehensive income. Upon expiration of these hedges, the amount recorded in other comprehensive income will be reclassified into earnings. The amounts expected to be reclassified from other comprehensive income to earnings in the next twelve months is immaterial.

Energy Trading & Risk Management Activities. LG&E conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns, in addition to the wholesale sale of excess asset capacity. Certain energy trading activities are accounted for on a mark-to-market basis in accordance with EITF 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities. Wholesale sales of excess asset capacity and wholesale purchases are treated as normal sales and purchases under SFAS No. 133 and SFAS No. 138 and are not marked-to-market.

The consensus reached by the EITF on EITF No. 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, to rescind EITF 98-10, effective for fiscal years after December 15, 2002, had no impact on LG&E's energy trading and risk management reporting as all contracts marked to market under EITF 98-10 are also within the scope of SFAS No. 133.

The table below summarizes LG&E's energy trading and risk management activities for 2002 and 2001 (in thousands of \$).

	2002	2001
Fair value of contracts at beginning of period, net liability	\$ (186)	\$ (17)
Fair value of contracts when entered into during the period	(65)	3,441
Contracts realized or otherwise settled during the period	448	(2,894)
Changes in fair values due to changes in assumptions	(353)	(716)
Fair value of contracts at end of period, net liability	\$ (156)	\$ (186)

No changes to valuation techniques for energy trading and risk management activities occurred during 2002. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at December 31, 2002, have a maturity of less than one year and are valued using prices actively quoted for proposed or executed transactions or quoted by brokers.

LG&E maintains policies intended to minimize credit risk and revalues credit exposures daily to monitor compliance with those policies. At December 31, 2002, 86% of the trading and risk management commitments were with counterparties rated BBB- equivalent or better.

Note 5 - Concentrations of Credit and Other Risk

Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed to perform as contracted. Concentrations of credit risk (whether on- or off-balance sheet) relate to groups of customers or counterparties that have similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

LG&E's customer receivables and gas and electric revenues arise from deliveries of natural gas to approximately 310,000 customers and electricity to approximately 382,000 customers in Louisville and adjacent areas in Kentucky. For the year ended December 31, 2002, 73% of total revenue was derived from electric operations and 27% from gas operations.

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In November 2001, LG&E and IBEW Local 2100 employees, which represent approximately 70% of LG&E's workforce, entered into a four-year collective bargaining agreement.

Note 6 - Pension Plans and Retirement Benefits

LG&E sponsors several qualified and non-qualified pension plans and other postretirement benefit plans for its employees. The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2002, and a statement of the funded status as of December 31 for each of the last two years (in thousands of \$):

	2002	2001
Pension Plans:		
Change in benefit obligation		
Benefit obligation at beginning of year	\$ 356,293	\$ 310,822
Service cost	1,484	1,311
Interest cost	24,512	25,361
Plan amendments	576	1,550
Curtailment loss	-	24,563
Special termination benefits	-	53,610
Benefits paid	(34,823)	(53,292)
Actuarial (gain) or loss and other	16,752	(7,632)
Benefit obligation at end of year	\$ 364,794	\$ 356,293
Change in plan assets		
Fair value of plan assets at beginning of year	\$ 233,944	\$ 333,378
Actual return on plan assets	(15,648)	(27,589)
Employer contributions and plan transfers	14,150	(17,134)
Benefits paid	(34,824)	(53,292)
Administrative expenses	(1,308)	(1,419)
Fair value of plan assets at end of year	\$ 196,314	\$ 233,944
Reconciliation of funded status		
Funded status	\$(168,480)	\$(122,349)
Unrecognized actuarial (gain) or loss	60,313	18,800
Unrecognized transition (asset) or obligation	(3,199)	(4,215)
Unrecognized prior service cost	32,265	35,435
Net amount recognized at end of year	\$ (79,101)	\$ (72,329)
Other Benefits:		
Change in benefit obligation		
Benefit obligation at beginning of year	\$ 89,946	\$ 56,981
Service cost	444	358
Interest cost	5,956	5,865
Plan amendments	-	1,487
Curtailment loss	-	8,645
Special termination benefits	-	18,089
Benefits paid	(4,988)	(4,877)
Actuarial (gain) or loss	1,875	3,398
Benefit obligation at end of year	\$ 93,233	\$ 89,946
Change in plan assets		
Fair value of plan assets at beginning of year	\$ 2,802	\$ 7,166

Actual return on plan assets	(533)	(765)
Employer contributions and plan transfers	4,213	1,282
Benefits paid	(5,004)	(4,881)
Fair value of plan assets at end of year	\$ 1,478	\$ 2,802

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Reconciliation of funded status		
Funded status	\$(91,755)	\$(87,144)
Unrecognized actuarial (gain) or loss	16,971	15,947
Unrecognized transition (asset) or obligation	6,697	7,346
Unrecognized prior service cost	5,995	5,302
Net amount recognized at end of year	\$(62,092)	\$(58,549)

There are no plan assets in the nonqualified plans due to the nature of the plans.

LG&E made a contribution to the pension plan of \$83.1 million in January 2003.

The following tables provide the amounts recognized in the balance sheet and information for plans with benefit obligations in excess of plan assets as of December 31, 2002 and 2001 (in thousands of \$):

	2002	2001
Pension Plans:		
Amounts recognized in the balance sheet consisted of:		
Prepaid benefits cost	\$ -	\$ -
Accrued benefit liability	(162,611)	(108,977)
Intangible asset	32,799	11,936
Accumulated other comprehensive income	50,711	24,712
Net amount recognized at year-end	\$(79,101)	\$(72,329)
Additional year-end information for plans with accumulated benefit obligations in excess of plan assets (1):		
Projected benefit obligation	\$ 364,794	\$ 356,293
Accumulated benefit obligation	358,956	352,477
Fair value of plan assets	196,314	233,944

(1) 2002 and 2001 includes all plans.

Other Benefits:		
Amounts recognized in the balance sheet consisted of:		
Accrued benefit liability	\$ (62,092)	\$ (58,549)
Additional year-end information for plans with benefit obligations in excess of plan assets:		
Projected benefit obligation	\$ 93,233	\$ 89,946
Fair value of plan assets	1,478	2,802

The following table provides the components of net periodic benefit cost for the plans for 2002 and 2001 (in thousands of \$):

2002 2001 Pension Plans:
Components of net periodic benefit cost

Service cost	\$ 1,484	\$ 1,311
Interest cost	24,512	25,361
Expected return on plan assets	(21,639)	(26,360)
Amortization of prior service cost	3,777	3,861
Amortization of transition (asset) or obligation	(1,016)	(1,000)
Recognized actuarial (gain) or loss	21	(777)
Net periodic benefit cost	\$ 7,139	\$ 2,396

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Special charges		
Prior service cost recognized	\$ -	\$ 10,237
Special termination benefits	-	53,610
Settlement loss	-	(2,244)
Total charges	\$ -	\$ 61,603
Other Benefits:		
Components of net periodic benefit cost		
Service cost	\$ 444	\$ 358
Interest cost	5,956	5,865

Expected return on plan assets	(204)	(420)
Amortization of prior service cost	920	951
Amortization of transition (asset) or obligation	650	719
Recognized actuarial (gain) or loss	116	(32)
Net periodic benefit cost	\$ 7,882	\$ 7,441
Special charges		
Curtailment loss	\$ -	\$ 6,671
Prior service cost recognized	-	2,391
Transition obligation recognized	-	4,743
Special termination benefits	-	18,089
Total charges	\$ -	\$ 31,894

The assumptions used in the measurement of LG&E's pension benefit obligation are shown in the following table:

	2002	2001
Weighted-average assumptions as of December 31:		
Discount rate	6.75%	7.25%
Expected long-term rate of return on plan assets	9.00%	9.50%
Rate of compensation increase	3.75%	4.25%

For measurement purposes, a 12.00% annual increase in the per capita cost of covered health care benefits was assumed for 2003. The rate was assumed to decrease gradually to 5.00% for 2014 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in assumed health care cost trend rates would have the following effects (in thousands of \$):

	1% Decrease	1% Increase
Effect on total of service and interest cost components for 2002	(201)	227
Effect on year-end 2002 postretirement benefit obligations	(3,001)	3,347

Thrift Savings Plans. LG&E has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under the plan, eligible employees may defer and contribute to the plan a portion of current compensation in order to provide future retirement benefits. LG&E makes contributions to the plan by matching a portion of the employee contributions. The costs of this matching were approximately \$1.7 million for 2002 and \$1.2 million for 2001.

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Note 7 - Income Taxes

Components of income tax expense are shown in the table below (in thousands of \$):

2002 2001

Included in operating expenses:

Current	- federal	\$26,231	\$42,997
	- state	8,083	8,668
Deferred	- federal - net	20,464	12,310
	- state - net	4,410	3,767
Amortization of investment tax credit		(4,153)	(4,290)
Total		55,035	63,452
Included in other income - net:			
Current	- federal	(1,667)	(1,870)
	- state	(430)	(483)
Deferred	- federal - net	(206)	285
	- state - net	(53)	73
Total		(2,356)	(1,995)
Total income tax expense		\$52,679	\$61,457

Components of net deferred tax liabilities included in the balance sheet are shown below (in thousands of \$):

	2002	2001
Deferred tax liabilities:		

Depreciation and other plant-related items	\$346,737	\$334,914
Other liabilities	64,734	77,611
	411,471	412,525
Deferred tax assets:		
Investment tax credit	22,012	23,713
Income taxes due to customers	18,431	19,709
Pensions	21,056	6,621
Accrued liabilities not currently deductible and other	36,747	64,339
	98,246	114,382
Net deferred income tax liability	\$313,225	\$298,143

A reconciliation of differences between the statutory U.S. federal income tax rate and LG&E's effective income tax rate follows:

	2002	2001
Statutory federal income tax rate	35.0%	35.0%
State income taxes, net of federal benefit	5.6	4.7
Amortization of investment tax credit	(2.9)	(2.6)
Other differences - net	(0.5)	(0.6)
Effective income tax rate	37.2%	36.5%

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Note 8 - Other Income - net

Other income - net consisted of the following at December 31 (in thousands of \$):

	2002	2001
Interest and dividend income	\$457	\$ 748
Gains on fixed asset disposals	421	1,217
Income taxes and other	(58)	965
Other income - net	\$820	\$2,930

Note 9 - First Mortgage Bonds and Pollution Control Bonds

Long-term debt and the current portion of long-term debt, summarized below (in thousands of \$), consists primarily of first mortgage bonds and pollution control bonds. Interest rates and maturities in the table below are for the amounts outstanding at December 31, 2002.

	Stated Interest Rates	Weighted Average Interest Rate	Maturities	Principal Amounts
Noncurrent portion	Variable - 5.90%	3.53%	2019-2032	\$ 328,104

Current portion Variable - 6.00% 2.08% 2003-2027 288,800

Under the provisions for some of LG&E's variable-rate pollution control bonds, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events, causing the bonds to be classified as current portion of long-term debt in the consolidated balance sheets. The average annualized interest rate for these bonds during 2002 was 1.61%.

LG&E's First Mortgage Bond, 6% Series of \$42.6 million is scheduled to mature in 2003. There are no other scheduled maturities of pollution control bonds for the five years subsequent to December 31, 2002.

In October 2002, LG&E issued \$41.7 million variable rate pollution bonds due October 1, 2032, and exercised its call option on \$41.7 million, 6.55% pollution control bonds due November 1, 2020.

In March 2002, LG&E refinanced four unsecured pollution control bonds with an aggregate principal balance of \$120 million and replaced them with secured pollution control bonds. The new bonds and the previous bonds were all variable rate bonds, and the maturity dates remained unchanged.

In September 2001, LG&E issued \$10.1 million variable rate tax-exempt environmental facility revenue bonds due September 1, 2027.

Annual requirements for the sinking funds of LG&E's First Mortgage Bonds (other than the First Mortgage Bonds issued in connection with

certain Pollution Control Bonds) are the amounts necessary to redeem 1% of the highest principal amount of each series of bonds at any time outstanding. Property additions (166 2/3% of principal amounts of bonds otherwise required to be so redeemed) have been applied in lieu of cash.

Substantially all of LG&E's utility plants are pledged as security for its first mortgage bonds. LG&E's indenture, as supplemented, provides that portions of retained earnings will not be available for the payment of dividends on common stock, under certain specified conditions. No portion of retained earnings is restricted by this provision as of December 31, 2002.

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Note 10 - Notes Payable

LG&E participates in an intercompany money pool agreement wherein LG&E Energy can make funds available to LG&E at market based rates up to \$400 million. The balance of the money pool loan from LG&E Energy was \$193.1 million at a rate of 1.61% and \$64.2 million at an average rate of 2.37%, at December 31, 2002 and 2001, respectively. LG&E also had outstanding commercial paper of \$30 million at an average rate of 2.54% at December 31, 2001. The remaining money pool availability at December 31, 2002, was \$206.9 million. LG&E Energy maintains facilities of \$450 million with affiliates to ensure funding availability for the money pool. The outstanding balance under these facilities as of December 31, 2002 was \$230 million, and availability of \$220 million remained.

Note 11 - Commitments and Contingencies

Construction Program. LG&E had approximately \$15.1 million of commitments in connection with its construction program at December 31, 2002. Construction expenditures for the years 2003 and 2004 are estimated to total approximately \$340.0 million, although all of this amount is not currently committed, including the purchase of four jointly owned CTs, \$89.0 million, and construction of NOx equipment, \$34.0 million.

Operating Lease. LG&E leases office space and accounts for its office space lease as an operating lease. Total lease expense for 2002 and 2001 less amounts contributed by the parent company, was \$1.6 million and \$1.1 million, respectively. The future minimum annual lease payments under this lease agreement for years subsequent to December 31, 2002, are as follows (in thousands of \$):

2003	\$ 3,371
2004	3,399
2005	3,467
2006	3,536
2007	3,607
Thereafter	29,794
Total	\$47,174

Environmental. The Clean Air Act imposed stringent new SO₂ and NO_x

emission limits on electric generating units. LG&E previously had installed scrubbers on all of its generating units. LG&E's strategy for Phase II SO₂ reductions, which commenced January 1, 2000, is to increase scrubber removal efficiency to delay additional capital expenditures and may also include fuel switching or upgrading scrubbers. LG&E met the NO_x emission requirements of the Act through installation of low-NO_x burner systems. LG&E's compliance plans are subject to many factors including developments in the emission allowance and fuel markets, future regulatory and legislative initiatives, and advances in clean air control technology. LG&E will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner.

In September 1998, the EPA announced its final "NO_x SIP Call" rule requiring states to impose significant additional reductions in NO_x emissions by May 2003, in order to mitigate alleged ozone transport impacts on the Northeast region. The Commonwealth of Kentucky is currently in the process of revising its SIP to require reductions in NO_x emissions from coal-fired generating units to the 0.15 lb./Mmbtu level on a system-wide basis. In related proceedings in response to petitions filed by various Northeast states, in December 1999, EPA issued a final rule pursuant to

Section 126 of the Clean Air Act directing similar NO_x reductions from a number of specifically targeted generating units including all LG&E units. As a result of appeals to both rules, the compliance date was extended to May 2004. All LG&E generating units are subject to the May 2004 compliance date under these NO_x emissions reduction rules.

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LG&E is currently implementing a plan for adding significant additional NO_x controls to its generating units. Installation of additional NO_x controls will proceed on a phased basis, with installation of controls commencing in late 2000 and continuing through the final compliance date. In addition, LG&E will incur additional operation and maintenance costs in operating new NO_x controls. LG&E believes its costs in this regard to be comparable to those of similarly situated utilities with like generation assets. LG&E had anticipated that such capital and operating costs are the type of costs that are eligible for recovery from customers under its environmental surcharge mechanism and believed that a significant portion of such costs could be recovered. In April 2001, the Kentucky Commission granted recovery of these costs for LG&E.

LG&E is also monitoring several other air quality issues which may potentially impact coal-fired power plants, including the appeal of the D.C.

Circuit's remand of the EPA's revised air quality standards for ozone and particulate matter, measures to implement EPA's regional haze rule, and EPA's December 2000 determination to regulate mercury emissions from power plants. In addition, LG&E is currently working with local regulatory authorities to review the effectiveness of remedial measures aimed at controlling particulate matter emissions from its Mill Creek Station. LG&E previously settled a number of property damage claims from adjacent residents and completed significant remedial measures as part of its ongoing capital construction program. LG&E is in the process of converting the Mill Creek Station to wet stack operation in an effort to resolve all outstanding issues related to particulate matter emissions.

LG&E owns or formerly owned three properties which are the location of past MGP operations. Various contaminants are typically found at such former MGP sites and environmental remediation measures are frequently required. With respect to the sites, LG&E has completed cleanups, obtained regulatory approval of site management plans, or reached agreements for other parties to assume responsibility for cleanup. Based on currently available information, management estimates that it will incur additional costs of \$400,000. Accordingly, an accrual of \$400,000 has been recorded in the accompanying financial statements at December 31, 2002 and 2001.

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Purchased Power. LG&E has a contract for purchased power with OVEC for various Mw capacities. The estimated future minimum annual payments under purchased power agreements for the years subsequent to December 31, 2002, are as follows (in thousands of \$):

2003	\$ 10,773
2004	10,116
2005	10,152
2006	10,816
2007	10,816
Thereafter	184,544
Total	\$237,217

Note 12 - Jointly Owned Electric Utility Plant

LG&E owns a 75% undivided interest in Trimble County Unit 1 which the Kentucky Commission has allowed to be reflected in customer rates.

Of the remaining 25% of the Unit, IMEA owns a 12.12% undivided interest, and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate ownership share of fuel cost, operation and maintenance expenses, and incremental assets.

The following data represent shares of the jointly owned property:

	LG&E	IMPA	IMEA	Total
Ownership interest	75%	12.88%	12.12%	100%
Mw capacity	386.2	66.4	62.4	515.0
LG&E's 75% ownership (in thousands of \$):				
Cost	\$595,747			
Accumulated depreciation	182,711			
Net book value	\$413,036			

Construction work in progress
(included above) \$12,867

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LG&E and KU jointly own the following combustion turbines (in thousands of \$):

	LG&E	KU	Total
Paddy's Run 13	Ownership %	53%	47%
	Mw capacity	84	74
	Cost	\$33,919	\$29,973
	Depreciation	1,711	1,499
	Net book value	\$32,208	\$28,474
E.W. Brown 5	Ownership %	53%	47%
	Mw capacity	71	63
	Cost	\$23,973	\$21,106
	Depreciation	1,206	1,052
	Net book value	\$22,767	\$20,054
E.W. Brown 6	Ownership %	38%	62%
	Mw capacity	59	95

	Cost	\$23,696	\$36,957	\$60,653
	Depreciation	1,770	4,201	5,971
	Net book value	\$21,926	\$32,756	\$54,682
E.W. Brown 7	Ownership %	38%	62%	100%
	Mw capacity	59	95	154
	Cost	\$23,607	\$44,792	\$68,399
	Depreciation	4,054	4,502	8,556
	Net book value	\$19,553	\$40,290	\$59,843
Trimble 5	Ownership %	29%	71%	100%
	Mw capacity	45	110	155
	Cost	\$15,970	\$39,045	\$55,015
	Depreciation	251	614	865
	Net book value	\$15,719	\$38,431	\$54,150
Trimble 6	Ownership %	29%	71%	100%
	Mw capacity	45	110	155
	Cost	\$15,961	\$39,025	\$54,986
	Depreciation	251	614	865
	Net book value	\$15,710	\$38,411	\$54,121
Trimble CT Pipeline	Ownership %	29%	71%	100%
	Cost	\$1,835	\$4,475	\$6,310
	Depreciation	39	96	135
	Net book value	\$1,796	\$4,379	\$6,175

See also Note 11, Construction Program, for LG&E's planned purchase of four jointly owned CTs in 2004.

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Note 13 - Segments of Business and Related Information

Effective December 31, 1998, LG&E adopted SFAS No. 131, Disclosure About Segments of an Enterprise and Related Information. LG&E is a regulated public utility engaged in the generation, transmission, distribution, and sale of electricity and the storage, distribution, and sale of natural gas. Financial data for business segments, follow (in thousands of \$):

	Electric	Gas	Total
2002			
Operating revenues	\$736,042 (a)	\$267,693	\$1,003,735
Depreciation and amortization	90,248	15,658	105,906
Interest income	381	76	457
Interest expense	24,837	4,968	29,805
Operating income taxes	49,010	6,025	55,035
Net income	79,246	9,683	88,929
Total assets	2,105,956	455,122	2,561,078
Construction expenditures	195,662	24,754	220,416
2001			
Operating revenues	\$673,772 (b)	\$290,775	\$964,547
Depreciation and amortization	85,572	14,784	100,356
Interest income	616	132	748
Interest expense	31,295	6,627	37,922
Operating income taxes	55,527	7,925	63,452
Net income	95,103	11,768	106,781
Total assets	1,985,252	463,102	2,448,354
Construction expenditures	227,107	25,851	252,958

(a) Net of provision for rate collections of \$12.3 million.

(b) Net of provision for rate refunds of \$.7 million.

Note 14 - Selected Quarterly Data (Unaudited)

Selected financial data for the four quarters of 2002 and 2001 are shown below. Because of seasonal fluctuations in temperature and other factors, results for quarters may fluctuate throughout the year.

	March	Quarters Ended		
		June	September	December
(Thousands of \$)				
2002				
Operating revenues	\$278,005	\$216,163	\$243,074	\$266,493
Net operating income	28,748	22,410	41,652	25,104
Net income	20,943	15,256	34,204	18,526
Net income available				

for common stock	19,878	14,207	33,129	17,469
2001				
Operating revenues	\$308,929	\$212,918	\$229,848	\$212,852
Net operating income				
(loss) (a)	(43,732)	37,624	49,092	98,789
Net income (loss) (a)	(54,115)	28,467	40,270	92,159
Net income (loss)				
available for				
common stock (a)	(55,413)	27,247	39,160	91,048

(a) Loss resulted from the VDT pre-tax charge of \$144.0 million in March 2001, which was reversed in December 2001. See Note 3.

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Note 15 - Subsequent Events

LG&E made a contribution to the pension plan of \$83.1 million in January 2003.

On March 18, 2003, the Kentucky Commission approved LG&E and KU's joint application for the acquisition of four CTs from an unregulated affiliate, LG&E Capital Corp. The total projected construction cost for the turbines, expected to be available for June 2004 in-service, is \$227.4 million. The requested ownership share of the turbines is 63% for KU and 37% for LG&E.

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Louisville Gas and Electric Company REPORT OF MANAGEMENT

The management of Louisville Gas and Electric Company is responsible for the preparation and integrity of the financial statements and related information. These statements have been prepared in accordance with accounting principles generally accepted in the United States applied on a consistent basis and, necessarily, include amounts that reflect the best estimates and judgment of management.

LG&E's 2002 and 2001 financial statements have been audited by PricewaterhouseCoopers LLP, independent accountants. Management made available to PricewaterhouseCoopers LLP all LG&E's financial records and related data as well as the minutes of shareholders' and directors' meetings.

Management has established and maintains a system of internal controls that provides reasonable assurance that transactions are completed in accordance with management's authorization, that assets are safeguarded and that financial statements are prepared in conformity with generally accepted accounting principles. Management believes that an adequate system of internal controls is maintained through the selection and training of personnel, appropriate division of responsibility, establishment and communication of policies and procedures and by regular reviews of internal accounting controls by LG&E's internal auditors. Management reviews and modifies its system of internal controls in light of changes in conditions and operations, as well as in response to recommendations from the internal and external auditors. These recommendations for the year ended December 31, 2002, did not identify any material weaknesses in the design and operation of LG&E's internal control structure.

In carrying out its oversight role for the financial reporting and internal controls of LG&E, the Board of Directors meets regularly with LG&E's independent public accountants, internal auditors and management. The Board of Directors reviews the results of the independent accountants' audit of the financial statements and their audit procedures, and discusses the adequacy of internal accounting controls. The Board of Directors also approves the annual internal auditing program and reviews the activities and results of the internal auditing function. Both the independent public accountants and the internal auditors have access to the Board of Directors at any time.

Louisville Gas and Electric Company maintains and internally communicates a written code of business conduct that addresses, among other items, potential conflicts of interest, compliance with laws, including those relating to financial disclosure, and the confidentiality of proprietary information.

S. Bradford Rives
Chief Financial Officer

Louisville Gas and Electric Company
Louisville, Kentucky
November 12, 2003

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REPORT OF INDEPENDENT ACCOUNTANTS

To the Shareholders of Louisville Gas and Electric Company and Subsidiary:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of capitalization, income, retained earnings, cash flows and comprehensive income present fairly, in all material respects, the financial position of Louisville Gas and Electric Company and Subsidiary (the "Company"), a wholly-owned subsidiary of LG&E Energy Corp., at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. 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 audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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 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, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the financial statements, effective January 1, 2003, the Company adopted EITF No. 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.

*/s/ PricewaterhouseCoopers LLP
Louisville, Kentucky
January 21, 2003, except for Note 1 as to which the date is November 12,
2003*

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INDEX OF ABBREVIATIONS

Capital Corp.	LG&E Capital Corp.
Clean Air Act	The Clean Air Act, as amended in 1990
CCN	Certificate of Public Convenience and Necessity
CT	Combustion Turbines
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEl	Electric Energy, Inc.
EITF	Emerging Issues Task Force Issue
E.ON	E.ON AG
EPA	U.S. Environmental Protection Agency
ESM	Earnings Sharing Mechanism
F	Fahrenheit
FAC	Fuel Adjustment Clause
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FT and FT-A	Firm Transportation
GSC	Gas Supply Clause
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
KU Energy	KU Energy Corporation
KU R	KU Receivables LLC
kV	Kilovolts
Kva	Kilovolt-ampere
KW	Kilowatts
Kwh	Kilowatt hours
LEM	LG&E Energy Marketing Inc.
LG&E	Louisville Gas and Electric Company
LG&E Energy	LG&E Energy Corp.
LG&E R	LG&E Receivables LLC
LG&E Services	LG&E Energy Services Inc.
Mcf	Thousand Cubic Feet
MGP	Manufactured Gas Plant
MISO	Midwest Independent System Operator
Mmbtu	Million British thermal units
Moody's	Moody's Investor Services, Inc.
Mw	Megawatts
Mwh	Megawatt hours
NNS	No-Notice Service
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen Oxide
OATT	Open Access Transmission Tariff
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation

PBR	Performance-Based Ratemaking
PJM	Pennsylvania, New Jersey, Maryland Interconnection
Powergen	Powergen Limited (formerly Powergen plc)
PUHCA	Public Utility Holding Company Act of 1935
ROE	Return on Equity
RTO	Regional Transmission Organization
S&P	Standard & Poor's Rating Services
SCR	Selective Catalytic Reduction
SEC	Securities and Exchange Commission

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SERP	Supplemental Employee Retirement Plan
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SMD	Standard Market Design
SO2	Sulfur Dioxide
Tennessee Gas	Tennessee Gas Pipeline Company
Texas Gas	Texas Gas Transmission Corporation
TRA	Tennessee Regulatory Authority
Trimble County	LG&E's Trimble County Unit 1
USWA	United Steelworkers of America

Utility Operations Operations of LG&E and KU VDT Value Delivery Team Process Virginia Commission Virginia State Corporation
Commission Virginia Staff Virginia State Corporation Commission Staff

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Kentucky Utilities Company and Subsidiary Consolidated Statements of Income

(Thousands of \$)

	Years Ended December 31	
	2002	2001
OPERATING REVENUES:		
Electric (Note 1)	\$848,637	\$821,675
Provision for rate collections (refunds) (Note 3)	13,027	(954)
Total operating revenues	861,664	820,721
OPERATING EXPENSES:		
Fuel for electric generation	250,117	236,985
Power purchased	131,400	118,410
Other operation expenses	144,118	118,359
Non-recurring charge (Note 3)	-	6,867
Maintenance	62,909	57,021
Depreciation and amortization (Note 1)	95,462	90,299
Federal and state income taxes (Note 7)	54,032	57,482
Property and other taxes	14,983	13,928
Total operating expenses	753,021	699,351
Net operating income	108,643	121,370
Other income - net (Note 3)	10,429	8,932
Interest charges	25,688	34,024
Net income before cumulative effect of a change in accounting principle	93,384	96,278
Cumulative effect of a change in accounting principle-accounting for Derivative instruments and hedging activities, net of tax	-	136
Net income	93,384	96,414
Preferred stock dividends	2,256	2,256
Net income available for common stock	\$ 91,128	\$ 94,158

Consolidated Statements of Retained Earnings
(Thousands of \$)

Years Ended December 31

	2002	2001
Balance January 1	\$410,896	\$347,238
Add net income	93,384	96,414
	504,280	443,652
Deduct: Cash dividends declared on stock:		
4.75% cumulative preferred	950	950
6.53% cumulative preferred	1,306	1,306
Common	-	30,500
	2,256	32,756
Balance December 31	\$502,024	\$410,896

The accompanying notes are an integral part of these consolidated financial statements.

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Kentucky Utilities Company and Subsidiary
Consolidated Statements of Comprehensive Income
(Thousands of \$)

	Years Ended December 31	
	2002	2001
Net income	\$ 93,384	\$ 96,414
Cumulative effect of change in accounting principle - Accounting for derivative instruments and hedging activities	-	2,647
Losses on derivative instruments and hedging activities	(2,647)	-
Additional minimum pension liability adjustment (Note 6)	(17,543)	-
Income tax benefit (expense) related to items of other comprehensive income	8,140	(1,059)
Other comprehensive (loss) income, net of tax	(12,050)	1,588
Comprehensive income	\$ 81,334	\$ 98,002

The accompanying notes are an integral part of these consolidated financial statements.

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Kentucky Utilities Company and Subsidiary Consolidated Balance Sheets

(Thousands of \$)

	December 31	
	2002	2001
ASSETS:		
Utility plant, at original cost (Note 1)	\$3,089,529	\$2,960,818
Less: reserve for depreciation	1,536,658	1,457,754
	1,552,871	1,503,064
Construction work in progress	191,233	103,402
	1,744,104	1,606,466
Other property and investments -		
less reserve of \$130 in 2002 and 2001	14,358	9,629
Current assets:		
Cash and temporary cash investments (Note 1)	5,391	3,295
Accounts receivable -less reserve of \$800 in 2002 and 2001	49,588	45,291
Materials and supplies - at average cost:		
Fuel (predominantly coal) (Note 1)	46,090	43,382
Other	26,408	26,188

Prepayments and other	6,584	4,942
	134,061	123,098
Deferred debits and other assets:		
Unamortized debt expense (Note 1)	4,991	4,316
Regulatory assets (Note 3)	65,404	66,467
Other	35,465	16,926
	105,860	87,709

\$1,998,383 \$ 1,826,902

CAPITAL AND LIABILITIES:

Capitalization (see statements of capitalization):

Common equity	\$ 814,107	\$ 735,029
Cumulative preferred stock	40,000	40,000
Long-term debt (Note 9)	346,562	434,506
	1,200,669	1,209,535
Current liabilities:		
Current portion of long-term debt (Note 9)	153,930	54,000
Notes payable to parent (Note 10)	119,490	47,790
Accounts payable	95,374	85,149
Accrued taxes	4,955	20,520
Other	21,442	22,150
	395,191	229,609
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Notes 1 and 7)	241,184	239,204
Investment tax credit, in process of amortization	8,500	11,455
Accumulated provision for pensions and related benefits (Note 6)	110,927	91,235
Regulatory liabilities (Note 3)	29,876	33,889
Other	12,036	11,975
	402,523	387,758
Commitments and contingencies (Note 11)	\$1,998,383	\$1,826,902

The accompanying notes are an integral part of these consolidated financial statements.

Kentucky Utilities Company and Subsidiary Consolidated Statements of Cash Flows

(Thousands of \$)

Years Ended December 31
2002 2001

CASH FLOWS FROM OPERATING ACTIVITIES:

Net income	\$ 93,384	\$ 96,414
Items not requiring cash currently:		
Depreciation and amortization	95,462	90,299
Deferred income taxes - net	(2,038)	(12,088)
Investment tax credit - net	(2,955)	(3,446)
Other	(1,267)	11,776
Change in certain net current assets:		
Accounts receivable	(8,497)	28
Materials and supplies	(2,928)	(31,263)
Accounts payable	10,225	8,810
Accrued taxes	(15,565)	898
Prepayments and other	(2,350)	(6,033)
Sale of accounts receivable (Note 1)	4,200	45,100
Other	8,086	(12,364)
Net cash flows from operating activities	175,757	188,131
CASH FLOWS FROM INVESTING ACTIVITIES:		
Proceeds from sales of securities	-	3,480

Construction expenditures	(237,909)	(142,425)
Net cash flows from investing activities	(237,909)	(138,945)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Short-term borrowings and repayments	71,700	(13,449)
Retirement of long-term debt	(133,930)	-
Issuance of long-term debt	128,734	-
Additional paid-in capital	-	-
Payment of dividends	(2,256)	(32,756)
Net cash flows used for financing activities	64,248	(46,205)
Change in cash and temporary cash investments	2,096	2,981
Cash and temporary cash investments at beginning of year	3,295	314
Cash and temporary cash investments at end of year	\$ 5,391	\$ 3,295
Supplemental disclosures of cash flow information:		
Cash paid during the year for:		
Income taxes	\$59,580	\$72,432
Interest on borrowed money	37,866	39,829

The accompanying notes are an integral part of these consolidated financial statements.

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Kentucky Utilities Company and Subsidiary Consolidated Statements of Capitalization

(Thousands of \$)

December 31
2002 2001

COMMON EQUITY:

Common stock, without par value -
authorized 80,000,000 shares, outstanding

37,817,878 shares	\$ 308,140	\$ 308,140
Additional paid-in-capital	15,000	15,000
Accumulated other comprehensive income	(10,462)	1,588
Other	(595)	(595)
Retained earnings	502,024	410,896
	814,107	735,029

CUMULATIVE PREFERRED STOCK:

Shares Current

Outstanding Redemption Price

Without par value,
5,300,000 shares authorized -
4.75% series, \$100 stated value

Redeemable on 30 days notice by KU	200,000	\$101.00	20,000	20,000
6.53% series, \$100 stated value	200,000	Not redeemable	20,000	20,000
			40,000	40,000

LONG-TERM DEBT (Note 9):

First mortgage bonds -				
Q due June 15, 2003, 6.32%		62,000		62,000
S due January 15, 2006, 5.99%		36,000		36,000
P due May 15, 2007, 7.92%		53,000		53,000
R due June 1, 2025, 7.55%		50,000		50,000
P due May 15, 2027, 8.55%		33,000		33,000
Pollution control series:				

1B due February 1, 2018, 6.25%	-	20,930
2B due February 1, 2018, 6.25%	-	2,400
3B due February 1, 2018, 6.25%	-	7,200
4B due February 1, 2018, 6.25%	-	7,400
8, due September 15, 2016, 7.45%	-	96,000
9, due December 1, 2023, 5.75%	50,000	50,000
10, due November 1, 2024, variable %	54,000	54,000
11, due May 1, 2023, variable %	12,900	12,900
12, due February 1, 2032, variable %	20,930	-
13, due February 1, 2032, variable %	2,400	-
14, due February 1, 2032, variable %	7,400	-
15, due February 1, 2032, variable %	7,200	-
16, due October 1, 2032, variable %	96,000	-
Long-term debt marked to market (Note 4)	15,662	3,676
 Total bonds outstanding	 500,492	 488,506
 Less current portion of long-term debt	 153,930	 54,000
 Long-term debt	 346,562	 434,506
 Total capitalization	 \$1,200,669	 \$1,209,535

The accompanying notes are an integral part of these consolidated financial statements.

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Kentucky Utilities Company and Subsidiary Notes to Consolidated Financial Statements

Note 1 - Summary of Significant Accounting Policies

KU, a subsidiary of LG&E Energy and an indirect subsidiary of Powergen and E.ON, is a regulated public utility engaged in the generation, transmission, distribution, and sale of electric energy. LG&E Energy is an exempt public utility holding company with wholly owned subsidiaries including LG&E, KU, Capital Corp., LEM, and LG&E Services. All of KU's Common Stock is held by LG&E Energy. KU has one wholly owned consolidated subsidiary, KU R.

On December 11, 2000, LG&E Energy was acquired by Powergen. On July 1, 2002, E.ON, a German company, completed its acquisition of Powergen plc (now Powergen Limited). E.ON had announced its pre-conditional cash offer of 5.1 billion pounds sterling (\$7.3 billion) for Powergen on April 9, 2001. Powergen and E.ON are registered public utility holding companies under PUHCA. No costs associated with these acquisitions nor any of the effects of purchase accounting have been reflected in the financial statements of KU.

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2002 presentation with no impact on the balance sheet totals or previously reported income.

Utility Plant. KU's utility plant is stated at original cost, which includes payroll-related costs such as taxes, fringe benefits, and administrative and general costs. Construction work in progress has been included in the rate base for determining retail customer rates. KU has not recorded any significant allowance for funds used during construction.

The cost of plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost, plus removal expense less salvage value, is charged to the reserve for depreciation. When complete operating units are disposed of, appropriate adjustments are made to the reserve for depreciation and gains and losses, if any, are recognized.

Depreciation and Amortization. Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. Pursuant to a final order of the Kentucky Commission dated December 3, 2001, KU implemented new depreciation rates effective January 1, 2001. The amounts provided were approximately 3.1% in 2002 and 3.1% in 2001, of average depreciable plant. Of the amount provided for depreciation at December 31, 2002 and 2001, respectively, approximately 0.7% was related to the retirement, removal and disposal costs of long lived assets.

Cash and Temporary Cash Investments. KU considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents. Temporary cash investments are carried at cost, which approximates fair value.

Fuel Inventories. Fuel inventories of \$46.1 million and \$43.4 million at December 31, 2002 and 2001, respectively, are included in Fuel in the balance sheet. The inventory is accounted for using the average-cost method.

Financial Instruments. KU uses over-the-counter interest-rate swap agreements to hedge its exposure to interest rates. Gains and losses on interest-rate swaps used to hedge interest rate risk are reflected in interest charges monthly. See Note 4 - Financial Instruments.

Unamortized Debt Expense. Debt expense is capitalized in deferred debits and amortized over the lives of the related bond issues, consistent with regulatory practices.

Deferred Income Taxes. Deferred income taxes are recognized at currently enacted tax rates for all material temporary differences between the financial reporting and income tax basis of assets and liabilities.

Investment Tax Credits. Investment tax credits resulted from provisions of the tax law that permitted a reduction of KU's tax liability based on credits for certain construction expenditures. Deferred investment tax credits are being amortized to income over the estimated lives of the related property that gave rise to the credits.

Revenue Recognition. Revenues are recorded based on service rendered to customers through month-end. KU accrues an estimate for unbilled revenues from each meter reading date to the end of the accounting period. The unbilled revenue estimates included in accounts receivable were approximately \$36.4 million and \$33.4 million at December 31, 2002, and 2001, respectively. KU recorded electric revenues that resulted from sales to a related party, LG&E, of \$34.6 million and \$31.1 million for years ended December 31, 2002 and 2001, respectively. See Note 3, Rates and Regulatory Matters.

With the adoption of EITF 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, revenues on the income statement are shown net of cost associated with trading activities. As a result KU has netted the power purchased expense for trading activities against operating revenue for all years presented.

Fuel Costs. The cost of fuel for electric generation is charged to expense as used.

Management's Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent items at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. See Note 11, Commitments and Contingencies, for a further discussion.

Accounts Receivable Securitization. SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, revises the standards for accounting for securitizations and other transfers of financial assets and collateral and requires certain disclosures, and provides accounting and reporting standards for transfers and servicing of financial assets and extinguishments of liabilities. SFAS No. 140 was adopted in the first quarter of 2001, when KU entered into an accounts receivable securitization transaction.

On February 6, 2001, KU implemented an accounts receivable securitization program. The purpose of this program is to enable KU to accelerate the receipt of cash from the collection of retail accounts receivable, thereby reducing dependence upon more costly sources of working capital. The securitization program allows for a percentage of eligible receivables to be sold. Eligible receivables are generally all receivables associated with retail sales that have standard terms and are not past due. KU is able to terminate this program at any time without penalty. If there is a significant deterioration in the payment record of the receivables by the retail customers or if KU fails to meet certain covenants regarding the program, the program may terminate at the election of the financial institutions. In this case, payments from retail customers would first be used to repay the financial institutions participating in the program, and would then be available for use by KU.

As part of the program, KU sold retail accounts receivables to a wholly owned subsidiary, KU R. Simultaneously, KU R entered into two separate

three-year accounts receivable securitization facilities with two financial institutions and their affiliates whereby KU R can sell, on a revolving basis, an undivided interest in certain of its receivables and receive up to \$50 million from an unrelated third party purchaser. The effective cost of the receivables programs is comparable to KU's lowest cost source of capital, and is based on prime rated commercial paper. KU retains servicing rights of the sold receivables through two separate servicing agreements with the third party purchaser. KU has obtained an opinion from independent legal counsel indicating these transactions qualify as a true sale of receivables. As of December 31, 2002, the outstanding program balance was \$49.3 million. KU is considering unwinding its accounts receivable securitization arrangements involving KU R during 2003.

The allowance for doubtful accounts associated with the eligible securitized receivables was \$520,000 at December 31, 2002. This allowance is based on historical experience of KU. Each securitization facility contains a fully funded reserve for uncollectible receivables.

New Accounting Pronouncements.

SFAS No. 143, Accounting for Asset Retirement Obligations was issued in 2001. SFAS No. 143 establishes accounting and reporting standards for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs.

The effective implementation date for SFAS No. 143 is January 1, 2003. Management has calculated the impact of SFAS No. 143 and the recently released FERC NOPR No. RM02-7, Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations. As of January 1, 2003, KU recorded asset retirement obligation (ARO) assets in the amount of \$8.6 million and liabilities in the amount of \$18.5 million. KU also recorded a cumulative effect adjustment in the amount of \$9.9 million to reflect the accumulated depreciation and accretion of ARO assets at the transition date less amounts previously accrued under regulatory depreciation. KU recorded offsetting regulatory assets of \$9.9 million, pursuant to regulatory treatment prescribed under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. Also pursuant to SFAS No. 71, KU recorded regulatory liabilities in the amount of \$888,000 offsetting removal costs previously accrued under regulatory accounting in excess of amounts allowed under SFAS No. 143.

KU also expects to record ARO accretion expense of approximately \$1.2 million, ARO depreciation expense of approximately \$176,000 and an offsetting regulatory credit in the income statement of approximately \$1.4 million in 2003, pursuant to regulatory treatment prescribed under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. The accretion, depreciation and regulatory credit will be annual adjustments. SFAS No. 143 will have no impact on the results of the operation of KU.

KU asset retirement obligations are primarily related to the final retirement of generating units. KU transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under SFAS No. 143, no material asset retirement obligations will be recorded for transmission and distribution assets.

KU adopted EITF No. 98-10, Accounting for Energy Trading and Risk Management Activities, effective January 1, 1999. This pronouncement required that energy trading contracts be marked to market on the balance sheet, with the gains and losses shown net in the income statement.

The EITF clarified accounting standards related to energy trading activities under EITF Issue 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in

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Energy Trading and Risk Management Activities. EITF No. 02-03 established the following:

- Rescinded EITF No. 98-10,
- Contracts that do not meet the definition of a derivative under SFAS No. 133 should not be marked to fair market value, and
- Revenues should be shown in the income statement net of costs associated with trading activities, whether or not the trades are physically settled.

With the rescission of EITF No. 98-10, energy trading contracts that do not also meet the definition of a derivative under SFAS No. 133 must be accounted for as executory contracts. Contracts previously recorded at fair value under EITF No. 98-10 that are not also derivatives under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, must be restated to historical cost through a cumulative effect adjustment. The rescission of this standard had no impact on financial position or results of operations of KU since all contracts marked to market under EITF No. 98-10 are also within the scope of SFAS No. 133.

As a result of EITF No. 02-03, KU has netted the power purchased expense for trading activities against electric operating revenue to reflect this accounting change. KU applied this guidance to all prior periods, which had no impact on previously reported net income or common equity.

	2002	2001
Gross electric operating revenues	\$875,192	\$860,426
Less costs reclassified from power purchased	26,555	38,751
Net electric operating revenues reported	\$848,637	\$821,675
Gross power purchased	\$157,955	\$157,161
Less costs reclassified to revenues	26,555	38,751
Net power purchased reported	\$131,400	\$118,410

In January 2003, the Financial Accounting Standards Board issued Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51 (FIN 46). FIN 46 requires certain variable interest entities to be consolidated by the primary beneficiary of the entity if the equity investors in the entity do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. FIN 46 is effective immediately for all new variable interest entities created or acquired after January 31, 2003. For variable interest entities created or acquired prior to February 1, 2003, the provisions of FIN 46 must be applied for the first interim or annual period beginning after June 15, 2003. KU does not expect the adoption of this standard to have any impact on the financial position or results of operations.

Note 2 - Mergers and Acquisitions

On July 1, 2002, E.ON completed its acquisition of Powergen, including LG&E Energy, for approximately 5.1 billion pounds sterling (\$7.3 billion).

As a result of the acquisition, LG&E Energy became a wholly owned subsidiary (through Powergen) of E.ON and, as a result, KU also became an indirect subsidiary of E.ON. KU has continued its separate identity and serves customers in Kentucky, Virginia and Tennessee under its existing names. The preferred stock and debt securities of KU were not affected by this transaction and the utilities continue to file SEC reports. Following the acquisition, E.ON became, and Powergen remained, a registered holding company under PUHCA. KU, as a subsidiary of a registered holding company, is subject to additional regulations under PUHCA. As contemplated in their regulatory filings in connection with the E.ON acquisition, E.ON, Powergen and LG&E Energy completed an administrative reorganization to move the LG&E Energy group from an indirect Powergen subsidiary to an indirect E.ON subsidiary. This reorganization was effective in March 2003.

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LG&E Energy and KU Energy merged on May 4, 1998, with LG&E Energy as the surviving corporation. Management accounted for the merger as a pooling of interests and as a tax-free reorganization under the Internal Revenue Code. Following these acquisitions, KU has continued to maintain its separate identity and serve customers under its present name. Note 3 - Rates and Regulatory Matters

Accounting for the regulated utility business conforms with generally accepted accounting principles as applied to regulated public utilities and as prescribed by FERC, the Kentucky Commission and the Virginia Commission. KU is subject to SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, under which certain costs that would otherwise be charged to expense are deferred as regulatory assets based on expected recovery from customers in future rates. Likewise, certain credits that would otherwise be reflected as income are deferred as regulatory liabilities based on expected return to customers in future rates. KU's current or expected recovery of deferred costs and expected return of deferred credits is generally based on specific ratemaking decisions or precedent for each item. The following regulatory assets and liabilities were included in KU's balance sheets as of December 31 (in thousands of \$):

	2002	2001
VDT costs	\$ 38,375	\$ 48,811
Unamortized loss on bonds	9,456	6,142
LG&E/KU merger costs	2,046	6,139
One utility costs	873	4,365
ESM provision	13,500	-
Other	1,154	1,010
Total regulatory assets	65,404	66,467
Deferred income taxes - net	(28,854)	(32,872)
Other	(1,022)	(1,017)
Total regulatory liabilities	(29,876)	(33,889)
Regulatory assets - net	\$ 35,528	\$ 32,578

Kentucky Commission Settlement Order - VDT Costs. During the first quarter 2001, KU recorded a \$64 million charge for a workforce reduction program. Primary components of the charge were separation benefits, enhanced early retirement benefits, and health care benefits. The result of this workforce reduction was the elimination of approximately 300 positions, accomplished primarily through a voluntary enhanced severance program.

On June 1, 2001, KU filed an application (VDT case) with the Kentucky Commission to create a regulatory asset relating to these first quarter 2001 charges. The application requested permission to amortize these costs over a four-year period. The Kentucky Commission also opened a case to review a new depreciation study and resulting depreciation rates implemented in 2001.

KU reached a settlement in the VDT case as well as the other cases involving depreciation rates and ESM with all intervening parties. The settlement agreement was approved by the Kentucky Commission on December 3, 2001. The order allowed KU to set up a regulatory asset of \$54 million for the workforce reduction costs and begin amortizing these costs over a five year period starting in April 2001. The first quarter 2001 charge of \$64 million represented all employees who had accepted a voluntary enhanced

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severance program. Some employees rescinded their participation in the voluntary enhanced severance program and, along with the non-recurring charge of \$6.9 million for FERC and Virginia jurisdictions, thereby decreasing the original charge of the regulatory asset from \$64 million to \$54 million. The settlement will also reduce revenues approximately \$11 million through a surcredit on future bills to customers over the same five year period. The surcredit represents net savings stipulated by KU. The agreement also established KU's new depreciation rates in effect December 2001, retroactive to January 1, 2001. The new depreciation rates decreased depreciation expense by \$6.0 million in 2001.

PUHCA. LG&E Energy was purchased by Powergen on December 11, 2000. Effective July 1, 2002, Powergen was acquired by E.ON, which became a registered holding company under PUHCA. As a result, E.ON, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries are subject to extensive regulation by the SEC under PUHCA with respect to issuances and sales of securities, acquisitions and sales of certain utility properties, and intra-system sales of certain goods and services. In addition, PUHCA generally limits the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company. KU believes that it has adequate authority (including financing authority) under existing SEC orders and regulations to conduct its business. KU will seek additional authorization when necessary.

Environmental Cost Recovery. In June 2000, the Kentucky Commission approved KU's application for a CCN to construct up to four SCR NOx reduction facilities. The construction and subsequent operation of the SCRs is intended to reduce NOx emission levels to meet the EPA's mandated NOx emission level of 0.15 lbs./ Mmbtu by May 2004. In its order, the Kentucky Commission ruled that KU's proposed plan for construction was "reasonable, cost-effective and will not result in the wasteful duplication of facilities." In October 2000, KU filed an application with the Kentucky Commission to amend its Environmental Compliance Plan to reflect the addition of the proposed NOx reduction technology projects and to amend its ECR Tariff to include an overall rate of return on capital investments. Approval of KU's application in April 2001 allowed KU to begin to recover the costs associated with these new projects, subject to Kentucky Commission oversight during normal six-month and two-year reviews.

In August 2002, KU filed an application with the Kentucky Commission to amend its compliance plan to allow recovery of the cost of a new and additional environmental compliance facility. The estimated capital cost of the additional facilities is \$17.3 million. The Kentucky Commission conducted a public hearing on the case on December 20, 2002, final briefs were filed on January 15, 2003, and a final order was issued February 11, 2003. The final order approved recovery of the new environmental compliance facility totaling \$17.3 million. Cost recovery through the environmental surcharge of the approved project will begin with bills rendered in April 2003.

ESM. KU's electric rates are subject to an ESM. The ESM, initially in place for three years beginning in 2000, sets an upper and lower point for rate of return on equity, whereby if KU's rate of return for the calendar year falls within the range of 10.5% to 12.5%, no action is necessary. If earnings are above the upper limit, the excess earnings are shared 40% with ratepayers and 60% with shareholders; if earnings are below the lower limit, the earnings deficiency is recovered 40% from ratepayers and 60% from shareholders. By order of the Kentucky Commission, rate changes prompted by the ESM filing go into effect in April of each year subject to a balancing adjustment in successive periods. KU made its second ESM filing on March 1, 2002 for the calendar year 2001 reporting period. KU is in the process of refunding \$1 million to customers for the 2001 reporting period. KU estimated that the rate of return will fall below the lower limit, subject to Kentucky Commission approval, for the year ended December 31, 2002. The 2002 financial statements include an accrual to reflect the earnings deficiency of \$13.5 million to be recovered from customers commencing in April 2003.

On November 27, 2002, KU filed a revised ESM tariff which proposed continuance of the existing ESM through December 2005. The Kentucky Commission issued an order suspending the ESM tariff one day making the

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effective date January 2, 2003. In addition, the Kentucky Commission is conducting a management audit to review the ESM plan and reassess its reasonableness in 2003. KU and interested parties will have the opportunity to provide recommendations for modification and continuance of the ESM or other forms of alternative or incentive regulation.

DSM. In May 2001, the Kentucky Commission approved a plan that would expand LG&E's current DSM programs into the service territory served by KU. The filing included a rate mechanism that provided for concurrent recovery of DSM costs, provided an incentive for implementing DSM programs, and recovered revenues from lost sales associated with the DSM program based on program planning engineering estimates and post-implementation evaluation.

FAC. KU employs a FAC mechanism which allows KU to recover from customers' fuel costs associated with retail electric sales. In July 1999, the Kentucky Commission issued a series of orders requiring KU to refund approximately \$10.1 million resulting from reviews of the FAC from November 1994 to October 1998. In August 1999, after a rehearing request by KU, the Kentucky Commission issued a final order that reduced the refund obligation to \$6.7 million (\$5.8 million on a Kentucky jurisdictional basis) from the original order amount of \$10.1 million. KU implemented the refund from October 1999 through September 2000. Both KU and the KIUC appealed the order. Pending a decision on this appeal, a comprehensive settlement was reached by all parties and approved by the Kentucky Commission on May 17, 2002. Thereunder, KU agreed to credit its fuel clause in the amount of \$954,000 (refund made in June and July 2002), and the parties agreed on a prospective interpretation of the state's FAC regulation to ensure consistent and mutually acceptable application on a going-forward basis.

In December 2002, the Kentucky Commission initiated a two year review of the operation of KU's FAC for the period November 2000 through October 2002. Testimony in the review case was filed on January 20, 2003 and a public hearing was held February 18, 2003. Issues addressed at that time included the establishment of the current base fuel factor to be included in KU's base rates, verification of proper treatment of purchased power costs during unit outages, and compliance with fuel procurement policies and practices.

Kentucky Commission Administrative Case for Affiliate Transactions. In December 1997, the Kentucky Commission opened Administrative Case No. 369 to consider Kentucky Commission policy regarding cost allocations, affiliate transactions and codes of conduct governing the relationship between utilities and their non-utility operations and affiliates. The Kentucky Commission intended to address two major areas in the proceedings:
the tools and conditions needed to prevent cost shifting and cross- subsidization between regulated and non-utility operations; and whether a code of conduct should be established to assure that non-utility segments of the holding company are not engaged in practices that could result in unfair competition caused by cost shifting from the non-utility affiliate to the utility. During the period September 1998 to February 2000, the Kentucky Commission issued draft codes of conduct and cost allocation guidelines. In early 2000, the Kentucky General Assembly enacted legislation, House Bill 897, which authorized the Kentucky Commission to require utilities that provide nonregulated activities to keep separate accounts and allocate costs in accordance with procedures established by the Kentucky Commission. In the same Bill, the General Assembly set forth provisions to govern a utility's activities related to the sharing of information, databases, and resources between its employees or an affiliate involved in the marketing or the provision of nonregulated activities and its employees or an affiliate involved in the provision of

regulated services. The legislation became law in July 2000 and KU has been operating pursuant thereto since that time. On February 14, 2001, the Kentucky Commission published notice of their intent to promulgate new administrative regulations under the auspices of this new law. This effort is still on-going.

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Kentucky Commission Administrative Case for System Adequacy. On June 19, 2001, Kentucky Governor Paul E. Patton issued Executive Order 2001-771, which directed the Kentucky Commission to review and study issues relating to the need for and development of new electric generating capacity in Kentucky. The issues to be considered included the impact of new power plants on the electric supply grid, facility siting issues, and economic development matters, with the goal of ensuring a continued, reliable source of supply of electricity for the citizens of Kentucky and the continued environmental and economic vitality of Kentucky and its communities. In response to that Executive Order, in July 2001 the Kentucky Commission opened Administrative Case No. 387 to review the adequacy of Kentucky's generation capacity and transmission system. Specifically, the items reviewed were the appropriate level of reliance on purchased power, the appropriate reserve margins to meet existing and future electric demand, the impact of spikes in natural gas prices on electric utility planning strategies, and the adequacy of Kentucky's electric transmission facilities. KU, as a party to this proceeding, filed written testimony and responded to two requests for information. Public hearings were held October 2001 and KU filed a final brief in the case. In December 2001, the Kentucky Commission issued an order in which it noted that KU is responsibly addressing the long-term supply needs of native load customers and that current reserve margins are appropriate. However, due to the rapid pace of change in the industry, the order also requires KU to provide an annual assessment of supply resources, future demand, reserve margin, and the need for new resources.

Regarding the transmission system, the Kentucky Commission concluded that the transmission system within Kentucky can reliably serve native load and a significant portion of the proposed new unregulated power plants. However, it will not be able to handle the volume of transactions envisioned by FERC without future upgrades, the costs of which should be borne by those for whom the upgrades are required.

The Kentucky Commission pledged to continue to monitor all relevant issues and advocate Kentucky's interests at all opportunities.

FERC SMD NOPR. On July 31, 2002, the FERC issued a NOPR in Docket No. RM01-12-000 which would substantially alter the regulations governing the nation's wholesale electricity markets by establishing a common set of rules -- SMD. The SMD NOPR would require each public utility that owns, operates, or controls interstate transmission facilities to become an Independent Transmission Provider (ITP), belong to an RTO that is an ITP, or contract with an ITP for operation of its transmission assets. It would also establish a standardized congestion management system, real-time and day-ahead energy markets, and a single transmission service for network and point-to-point transmission customers. Review of the proposed rulemaking is underway and a final rule is expected during 2003. While it is expected that the SMD final rule will affect KU revenues and expenses, the specific impact of the rulemaking is not known at this time.

MISO. KU is a member of the MISO, which began commercial operations on February 1, 2002. MISO now has operational control over KU's high-voltage transmission facilities (100 kV and greater), while KU continues to control and operate the lower voltage transmission subject to the terms and conditions of the MISO OATT. As a transmission-owning member of MISO, KU also incurs administrative costs of MISO pursuant to Schedule 10 of the MISO OATT.

MISO also proposed to implement a congestion management system. FERC directed the MISO to coordinate its efforts with FERC's Rulemaking on SMD. On September 24, 2002, the MISO filed new rate schedules designated as Schedules 16 and 17, which provide for the collection of costs incurred by the MISO to establish day-ahead and real-time energy markets. The MISO proposed to recover these costs under Schedules 16 and 17 once service commences. If approved by FERC, these schedules will cause KU to incur additional costs. KU opposes the establishment of Schedules 16 and 17. This effort is still on-going and the ultimate impact of the two schedules, if approved, is not known at this time.

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ARO. In 2003, KU expects to record approximately \$11.3 million in regulatory assets and approximately \$888,000 in regulatory liabilities related to SFAS No. 143, Accounting for Asset Retirement Obligations.

Merger Surcredit. As part of the LG&E Energy merger with KU Energy, KU estimated non-fuel savings over a ten-year period following the merger. Costs to achieve these savings for KU of \$42.3 million were recorded in the second quarter of 1998, \$20.5 million of which was deferred and amortized over a five-year period pursuant to regulatory orders. Primary components of the merger costs were separation benefits, relocation costs, and transaction fees, the majority of which were paid by December 31, 1998. KU expensed the remaining costs associated with the merger (\$21.8 million) in the second quarter of 1998.

In approving the merger, the Kentucky Commission adopted KU's proposal to reduce its retail customers' bills based on one-half of the estimated merger-related savings, net of deferred and amortized amounts, over a five year period. The surcredit mechanism provides that 50% of the net non-fuel cost savings estimated to be achieved from the merger would be provided to ratepayers through a monthly bill credit, and 50% retained by the Companies, over a five-year period. The surcredit was allocated 53% to KU and 47% to LG&E. In that same order, the Commission required LG&E and KU, after the end of the five-year period, to present a plan for sharing with customers the then-projected non-fuel savings associated with the merger. The Companies submitted this filing on January 13, 2003, proposing to continue to share with customers, on a 50%/50% basis, the estimated fifth-year gross level of non-fuel savings associated with the merger. The filing is currently under review.

Any fuel cost savings are passed to Kentucky customers through the fuel adjustment clauses. See FAC above.

Note 4 - Financial Instruments

The cost and estimated fair values of KU's non-trading financial instruments as of December 31, 2002, and 2001 follow (in thousands of \$):

	2002		2001	
	Cost	Fair Value	Cost	Fair Value
Long-term debt (including current portion)	\$484,830	\$503,194	\$484,830	\$499,618
Interest-rate swaps	-	16,928	-	6,906

All of the above valuations reflect prices quoted by exchanges except for the swaps. The fair values of the swaps reflect price quotes from dealers or amounts calculated using accepted pricing models.

Interest Rate Swaps. KU uses interest rate swaps to hedge exposure to market fluctuations in certain of its debt instruments. Pursuant to policy, use of these financial instruments is intended to mitigate risk and earnings volatility and is not speculative in nature. Management has designated all of the interest rate swaps as hedge instruments. Financial instruments designated as fair value hedges are periodically marked to market with the resulting gains and losses recorded directly into net income to correspond with income or expense recognized from changes in market value of the items being hedged.

As of December 31, 2002 and 2001, KU was party to various interest rate swap agreements with aggregate notional amounts of \$153 million in 2002 and 2001. Under these swap agreements, KU paid variable rates based on either

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LIBOR or the Bond Market Association's municipal swap index averaging 2.36% and 2.54%, and received fixed rates averaging 7.13% and 7.13% at December 31, 2002 and 2001, respectively. The swap agreements in effect at December 31, 2002 have been designated as fair value hedges and mature on dates ranging from 2007 to 2025. For 2002, the effect of marking these financial instruments and the underlying debt to market resulted in immaterial pretax gains recorded in interest expense.

Interest rate swaps hedge interest rate risk on the underlying debt under SFAS 133, in addition to swaps being marked to market, the item being hedged must also be marked to market, consequently at December 31, 2002, KU's debt reflects a \$15.7 million mark to market adjustment.

Energy Trading & Risk Management Activities. KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns, in addition to the wholesale sale of excess asset capacity. Certain energy trading activities are accounted for on a mark-to-market basis in accordance with EITF 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and SFAS No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities. Wholesale sales of excess asset capacity and wholesale purchases are treated as normal sales and purchases under SFAS No. 133 and SFAS No. 138 and are not marked-to-market.

The consensus reached by the EITF on EITF No. 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, to rescind EITF 98-10, effective for fiscal years after December 15, 2002, had no impact on KU's energy trading and risk management reporting as all contracts marked to market under EITF 98-10 are also within the scope of SFAS No. 133.

The table below summarizes KU's energy trading and risk management activities for 2002 and 2001 (in thousands of \$).

	2002	2001
Fair value of contracts at beginning of period, net liability	\$ (186)	\$ (17)
Fair value of contracts when entered into during the period	(65)	3,441
Contracts realized or otherwise settled during the period	448	(2,894)
Changes in fair values due to changes in assumptions	(353)	(716)
Fair value of contracts at end of period, net liability	\$ (156)	\$ (186)

No changes to valuation techniques for energy trading and risk management activities occurred during 2002. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at December 31, 2002, have a maturity of less than one year and are valued using prices actively quoted for proposed or executed transactions or quoted by brokers.

KU maintains policies intended to minimize credit risk and revalues credit exposures daily to monitor compliance with those policies. At December 31, 2002, 86% of the trading and risk management commitments were with counterparties rated BBB- equivalent or better.

Note 5 - Concentrations of Credit and Other Risk

Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed to perform as contracted. Concentrations of credit risk (whether on- or off-balance sheet) relate to groups of customers or counterparties that have similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

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KU's customer receivables and revenues arise from deliveries of electricity to approximately 477,000 customers in over 600 communities and adjacent suburban and rural areas in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in five counties in southwestern Virginia and less than ten customers in Tennessee. For the year ended December 31, 2002, 100% of total utility revenue was derived from electric operations.

In August 2001, KU and its employees represented by IBEW Local 2100 entered into a two-year collective bargaining agreement. KU and its employees represented by USWA Local 9447-01 entered into a three-year collective bargaining agreement effective August 2002 and expiring August 2005. The employees represented by these two bargaining units comprise approximately 17% of KU's workforce.

Note 6 - Pension Plans and Retirement Benefits

KU sponsors qualified and non-qualified pension plans and other postretirement benefit plans for its employees. The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2002, and a statement of the funded status as of December 31 for each of the last two years (in thousands of \$):

	2002	2001
Pension Plans:		
Change in benefit obligation		
Benefit obligation at beginning of year	\$244,472	\$233,034
Service cost	2,637	2,761
Interest cost	16,598	17,534
Plan amendment	28	4
Change due to transfers	-	(16,827)
Curtailement loss	-	1,400
Special termination benefits	-	24,274
Benefits paid	(23,291)	(29,166)
Actuarial (gain) or loss and other	7,283	11,458
Benefit obligation at end of year	\$247,727	\$244,472
Change in plan assets		
Fair value of plan assets at beginning of year	\$216,947	\$244,677
Actual return on plan assets	(13,767)	18,155
Employer contributions and plan transfers	(99)	(15,300)
Benefits paid	(23,291)	(29,166)
Administrative expenses	(1,256)	(1,419)
Fair value of plan assets at end of year	\$178,534	\$216,947
Reconciliation of funded status		
Funded status	\$(69,193)	\$(27,525)
Unrecognized actuarial (gain) or loss	36,233	(20,581)
Unrecognized transition (asset) or obligation	(532)	(664)
Unrecognized prior service cost	10,106	11,027
Net amount recognized at end of year	\$(23,386)	\$(37,743)

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Other Benefits:		
Change in benefit obligation		
Benefit obligation at beginning of year	\$ 83,223	\$ 64,213
Service cost	610	495
Interest cost	6,379	5,433
Plan amendments	-	-
Curtailement loss	-	6,381
Special termination benefits	-	3,824
Benefits paid net of retiree contributions	(4,640)	(5,446)
Actuarial (gain) or loss	19,030	8,323
Benefit obligation at end of year	\$104,602	\$ 83,223
Change in plan assets		

Fair value of plan assets at beginning of year	\$ 14,330	\$ 23,762
Actual return on plan assets	(2,698)	(4,404)
Employer contributions and plan transfers	1,648	473
Benefits paid net of retiree contributions	(5,337)	(5,501)
Fair value of plan assets at end of year	\$ 7,943	\$ 14,330
Reconciliation of funded status		
Funded status	\$(96,659)	\$(68,893)
Unrecognized actuarial (gain) or loss	22,667	(437)
Unrecognized transition (asset) or obligation	11,209	12,290
Unrecognized prior service cost	2,891	3,548
Net amount recognized at end of year	\$(59,892)	\$(53,492)

There are no plan assets in the non-qualified plan due to the nature of the plan.

KU made a contribution to the pension plan of \$3.5 million in January 2003.

The following tables provide the amounts recognized in the balance sheet and information for plans with benefit obligations in excess of plan assets as of December 31, 2002 and 2001 (in thousands of \$):

2002 2001

Pension Plans:

Amounts recognized in the balance sheet consisted of:

Accrued benefit liability	\$ (51,035)	\$(37,743)
Intangible asset	10,106	-
Accumulated other comprehensive income	17,543	-
Net amount recognized at year-end	\$(23,386)	\$(37,743)

Additional year-end information for plans with accumulated benefit obligations in excess of plan assets (1):

Projected benefit obligation	\$247,727	\$244,472
Accumulated benefit obligation	229,569	224,261
Fair value of plan assets	178,534	216,947

(1) 2002 and 2001 includes all plans.

Other Benefits:

Amounts recognized in the balance sheet consisted of:

Accrued benefit liability	\$(59,892)	\$(53,492)
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Additional year-end information for plans with benefit obligations in excess of plan assets:

Projected benefit obligation	\$104,602	\$ 83,223
Fair value of plan assets	7,943	14,330

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The following table provides the components of net periodic benefit cost for the plans for 2002 and 2001 (in thousands of \$):

	2002	2001
Pension Plans:		
Components of net periodic benefit cost		
Service cost	\$ 2,637	\$ 2,761
Interest cost	16,598	17,534
Expected return on plan assets	(18,406)	(19,829)
Amortization of transition (asset) or obligation	(133)	(136)
Amortization of prior service cost	956	962
Recognized actuarial (gain) or loss	1	(120)
Net periodic benefit cost	\$ 1,653	\$ 1,172
Special charges		
Prior service cost recognized	\$ -	\$ 1,238
Special termination benefits	-	24,274
Total charges	\$ -	\$ 25,512

Other Benefits:		
Components of net periodic benefit cost		
Service cost	\$ 610	\$ 495
Interest cost	6,379	5,433
Expected return on plan assets	(1,022)	(1,313)
Amortization of prior service cost	691	740
Amortization of transition (asset) or obligation	1,081	1,193
Recognized actuarial (gain) or loss	343	(40)
Net periodic benefit cost	\$ 8,082	\$ 6,508
Special charges		
Transition obligation recognized	\$ -	\$ 7,638
Prior service cost recognized	-	1,613
Special termination benefits	-	3,824
Total charges	\$ -	\$ 13,075

The assumptions used in the measurement of KU's pension benefit obligation are shown in the following table:

2002 2001 Weighted-average assumptions as of December 31:

Discount rate	6.75%	7.25%
Expected long-term rate of return on plan assets	9.00%	9.50%
Rate of compensation increase	3.75%	4.25%

For measurement purposes, a 12.00% annual increase in the per capita cost of covered health care benefits was assumed for 2003. The rate was assumed to decrease gradually to 5.00% for 2014 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in assumed health care cost trend rates would have the following effects (in thousands of \$):

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	1% Decrease	1% Increase
Effect on total of service and interest cost components for 2002	(422)	479
Effect on year-end 2002 postretirement benefit obligations	(7,010)	7,972

Thrift Savings Plans. KU has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under the plan, eligible employees may defer and contribute to the plan a portion of current compensation in order to provide future retirement benefits. KU makes contributions to the plan by matching a portion of the employee contributions. The costs of this matching were approximately \$1.5 million for 2002 and \$1.4 million for 2001.

Note 7 - Income Taxes

Components of income tax expense are shown in the table below (in thousands of \$):

	2002	2001
Included in operating expenses:		
Current - federal	\$38,524	\$58,337
- state	10,494	13,465
Deferred - federal - net	3,467	(12,980)
- state - net	1,547	(1,340)
Total	54,032	57,482
Included in other income - net:		
Current - federal	(685)	(948)
- state	15	(268)
Deferred - federal - net	(195)	863
- state - net	(88)	222
Amortization of investment tax credit	(2,955)	(3,446)
Total	(3,908)	(3,577)
Total income tax expense	\$50,124	\$53,905

Components of net deferred tax liabilities included in the balance sheet are shown below (in thousands of \$):

	2002	2001
Deferred tax liabilities:		
Depreciation and other plant-related items	\$271,792	\$269,752
Other liabilities	30,378	33,376
	302,170	303,128
Deferred tax assets:		
Investment tax credit	3,431	4,623
Income taxes due to customers	11,609	13,263
Pensions	15,861	4,595
Accrued liabilities not currently deductible and other	30,085	41,443
	60,986	63,924
Net deferred income tax liability	\$241,184	\$239,204

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A reconciliation of differences between the statutory U.S. federal income tax rate and KU's effective income tax rate follows:

	2002	2001
Statutory federal income tax rate	35.0%	35.0%
State income taxes, net of federal benefit	5.5	5.4
Amortization of investment tax credit	(2.4)	(2.3)
Other differences - net	(3.2)	(2.2)
Effective income tax rate	34.9%	35.9%

The change in other differences is due to increased non-taxable earnings from an unconsolidated KU investment.

Note 8 - Other Income - net

Other income - net consisted of the following at December 31 (in thousands of \$):

	2002	2001
Equity in earnings - subsidiary company	\$ 6,697	\$ 1,803
Interest and dividend income	641	1,368
Gains on fixed asset disposals	157	1,844
Income taxes and other	2,934	3,917
Other income - net	\$10,429	\$ 8,932

Note 9 - First Mortgage Bonds and Pollution Control Bonds

Long-term debt and the current portion of long-term debt, summarized below (in thousands of \$), consists primarily of first mortgage bonds and pollution control bonds. Interest rates and maturities in the table below are for the amounts outstanding at December 31, 2002.

	Stated Interest Rates	Weighted Average Interest Rate	Maturities	Principal Amounts
Noncurrent portion	Variable - 8.55%	5.21%	2006-2032	\$346,562

Current portion Variable - 6.32% 3.58% 2003-2032 \$153,930

Under the provisions for KU's variable-rate pollution control bonds Series PCS 10, 12, 13, 14, and 15, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events, causing the bonds to be classified as current portion of long-term debt in the consolidated balance sheets. The average annualized interest rate for these bonds during 2002 was 1.58%.

In September 2002, KU issued \$96 million variable rate pollution control Series 16 due October 1, 2032, and exercised its call option on \$96 million, 7.45% pollution control Series 8 due September 15, 2016.

In May 2002, KU issued \$37.9 million variable rate pollution control Series 12, 13, 14 and 15 due February 1, 2032, and exercised its call option on \$37.9 million, 6.25% pollution control Series 1B, 2B, 3B, and 4B due February 1, 2018.

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KU's First Mortgage Bond, 6.32% Series Q of \$62 million is scheduled to mature in June 2003, KU's First Mortgage Bond, 5.99% Series S of \$36 million matures in 2006, and KU's First Mortgage Bond, 7.92% Series P of \$53 million matures in 2007. There are no scheduled maturities of Pollution Control Bonds for the five years subsequent to December 31, 2002.

Substantially all of KU's utility plant is pledged as security for its First Mortgage Bonds.

Note 10 - Notes Payable to Parent

KU participates in an intercompany money pool agreement wherein LG&E Energy can make funds available to KU at market based rates up to \$400 million. The balance of the money pool loan from LG&E Energy was \$119.5 million at a rate of 1.61% and \$47.8 million at an average rate of 2.37% at December 31, 2002 and 2001, respectively. The remaining money pool availability at December 31, 2002, was \$280.5 million. LG&E Energy maintains facilities of \$450 million with affiliates to ensure funding availability for the money pool. The outstanding balance under these facilities as of December 31, 2002 was \$230 million, and availability of \$220 million remained.

Note 11 - Commitments and Contingencies

Construction Program. KU had approximately \$6.2 million of commitments in connection with its construction program at December 31, 2002. Construction expenditures for the years 2003 and 2004 are estimated to total approximately \$550.0 million; although all of this is not currently committed, including the purchase of four jointly owned CTs, \$152.0 million, and construction of NOx equipment, \$177.0 million.

Operating Leases. KU leases office space, office equipment, and vehicles. KU accounts for these leases as operating leases. Total lease expense for 2002 and 2001 was \$2.6 million and \$2.8 million, respectively.

Environmental. The Clean Air Act imposed stringent new SO₂ and NO_x emission limits on electric generating units. KU met its Phase I SO₂ requirements primarily through installation of a scrubber on Ghent Unit 1. KU's strategy for Phase II SO₂ reductions, which commenced January 1, 2000, is to use accumulated emissions allowances to delay additional capital expenditures and may also include fuel switching or the installation of additional scrubbers. KU met the NO_x emission requirements of the Act through installation of low-NO_x burner systems. KU's compliance plans are subject to many factors including developments in the emission allowance and fuel markets, future regulatory and legislative initiatives, and advances in clean air control technology. KU will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner.

In September 1998, the EPA announced its final "NO_x SIP Call" rule requiring states to impose significant additional reductions in NO_x emissions by May 2003, in order to mitigate alleged ozone transport impacts on the Northeast region. The Commonwealth of Kentucky is currently in the process of revising its SIP to require reductions in NO_x emissions from coal-fired generating units to the 0.15 lb./Mmbtu level on a system-wide basis. In related proceedings in response to petitions filed by various Northeast states, in December 1999, EPA issued a final rule pursuant to

Section 126 of the Clean Air Act directing similar NO_x reductions from a number of specifically targeted generating units including all KU units in the eastern half of Kentucky. Additional petitions currently pending before EPA may potentially result in rules encompassing KU's remaining generating units. As a result of appeals to both rules, the compliance date was extended to May 2004. All KU generating units are subject to the May 2004 compliance date under these NO_x emissions reduction rules.

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KU is currently implementing a plan for adding significant additional NO_x controls to its generating units. Installation of additional NO_x controls will proceed on a phased basis, with installation of controls commencing in late 2000 and continuing through the final compliance date. In addition, KU will incur additional operation and maintenance costs in operating new NO_x controls. KU believes its costs in this regard to be comparable to those of similarly situated utilities with like generation assets. KU had anticipated that such capital and operating costs are the type of costs that are eligible for recovery from customers under its environmental surcharge mechanism and believed that a significant portion of such costs could be recovered. In April 2001, the Kentucky Commission granted recovery of these costs for KU.

KU is also monitoring several other air quality issues which may potentially impact coal-fired power plants, including the appeal of the D.C. Circuit's remand of the EPA's revised air quality standards for ozone and particulate matter, measures to implement EPA's regional haze rule, and EPA's December 2000 determination to regulate mercury emissions from power plants.

KU owns or formerly owned several properties that contained past MGP operations. Various contaminants are typically found at such former MGP sites and environmental remediation measures are frequently required. KU has completed the cleanup of a site owned by KU. With respect to other former MGP sites no longer owned by KU, KU is unaware of what, if any, additional exposure or liability it may have.

In October 1999, approximately 38,000 gallons of diesel fuel leaked from a cracked valve in an underground pipeline at KU's E.W. Brown Station. Under the oversight of EPA and state officials, KU commenced immediate spill containment and recovery measures which prevented the spill from reaching the Kentucky River. KU ultimately recovered approximately 34,000 gallons of diesel fuel. In November 1999, the Kentucky Division of Water issued a notice of violation for the incident. KU is currently negotiating with the state in an effort to reach a complete resolution of this matter. KU incurred costs of approximately \$1.8 million and received insurance reimbursement of \$1.2 million. In December 2002, the Department of Justice (DOJ) sent correspondence to KU regarding a potential per-day fine for failure to timely submit a

spill control plan and a per-gallon fine for the amount of oil discharged. KU and the DOJ have commenced settlement discussions using existing DOJ settlement guidelines on this matter.

In April 2002, the EPA sent correspondence to KU regarding potential exposure in connection with \$1.5 million in completed remediation costs associated with a transformer scrap-yard. KU believes it is one of the more remote among a number of potentially responsible parties and has entered into settlement discussions with the EPA on this matter.

Purchased Power. KU has purchase power arrangements with OMU, EEI and other parties. Under the OMU agreement, which expires on January 1, 2020, KU purchases all of the output of a 400-Mw generating station not required by OMU. The amount of purchased power available to KU during 2003-2007, which is expected to be approximately 8% of KU's total kWh native load energy requirements, is dependent upon a number of factors including the units' availability, maintenance schedules, fuel costs and OMU requirements. Payments are based on the total costs of the station allocated per terms of the OMU agreement, which generally follow delivered kWh. Included in the total costs is KU's proportionate share of debt service requirements on \$149.6 million of OMU bonds outstanding at December 31, 2002. The debt service is allocated to KU based on its annual allocated share of capacity, which averaged approximately 50% in 2002.

KU has a 20% equity ownership in EEI, which is accounted for on the equity method of accounting. KU's entitlement is 20% of the available capacity of a 1,000 Mw station. Payments are based on the total costs of the station allocated per terms of an agreement among the owners, which generally follow delivered kWh.

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KU has several other contracts for purchased power of various Mw capacities.

The estimated future minimum annual payments under purchased power agreements for the years subsequent to December 31, 2002, are as follows (in thousands of \$):

2003	\$ 34,317
2004	39,653
2005	39,653
2006	39,884
2007	39,994
Thereafter	643,946
Total	\$837,447

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Note 12 - Jointly Owned Electric Utility Plant

LG&E and KU jointly own the following combustion turbines (in thousands of \$):

		LG&E	KU	Total
Paddy's Run 13	Ownership %	53%	47%	100%
	Mw capacity	84	74	158
	Cost	\$33,919	\$29,973	\$63,892
	Depreciation	1,711	1,499	3,210
	Net book value	\$32,208	\$28,474	\$60,682
E.W. Brown 5	Ownership %	53%	47%	100%
	Mw capacity	71	63	134
	Cost	\$23,973	\$21,106	\$45,079
	Depreciation	1,206	1,052	2,258
	Net book value	\$22,767	\$20,054	\$42,821
E.W. Brown 6	Ownership %	38%	62%	100%
	Mw capacity	59	95	154
	Cost	\$23,696	\$36,957	\$60,653
	Depreciation	1,770	4,201	5,971
	Net book value	\$21,926	\$32,756	\$54,682
E.W. Brown 7	Ownership %	38%	62%	100%
	Mw capacity	59	95	154
	Cost	\$23,607	\$44,792	\$68,399
	Depreciation	4,054	4,502	8,556
	Net book value	\$19,553	\$40,290	\$59,843
Trimble 5	Ownership %	29%	71%	100%
	Mw capacity	45	110	155
	Cost	\$15,970	\$39,045	\$55,015
	Depreciation	251	614	865
	Net book value	\$15,719	\$38,431	\$54,150

Trimble 6	Ownership %	29%	71%	100%
	Mw capacity	45	110	155
	Cost	\$15,961	\$39,025	\$54,986
	Depreciation	251	614	865
	Net book value	\$15,710	\$38,411	\$54,121
Trimble CT Pipeline	Ownership %	29%	71%	100%
	Cost	\$1,835	\$4,475	\$6,310
	Depreciation	39	96	135
	Net book value	\$1,796	\$4,379	\$6,175

See also Note 11, Construction Program, for KU's planned purchase of four jointly owned CTs in 2004.

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Note 13 - Selected Quarterly Data (Unaudited)

Selected financial data for the four quarters of 2002 and 2001 are shown below. Because of seasonal fluctuations in temperature and other factors, results for quarters may fluctuate throughout the year.

	March	Quarters Ended		
		June	September	December
	(Thousands of \$)			
2002				
Revenues	\$209,023	\$196,020	\$235,059	\$221,562
Net operating income	28,200	20,047	31,028	29,368
Net income	24,357	12,752	31,085	25,190
Net income available for common stock	23,793	12,188	30,521	24,626
2001				
Revenues	\$206,162	\$201,745	\$212,438	\$200,376
Net operating income (loss) (a)	(344)	28,422	30,253	63,039
Net income (loss) (a)	(7,995)	22,080	26,340	55,989
Net income (loss) available for common stock (a)	(8,559)	21,516	25,776	55,425

(a) Loss resulted from the VDT pre-tax charge of \$64.0 million in March 2001, which \$57.1 million was reversed in December 2001. See Note 3.

Note 14 - Subsequent Events

In January 2003, the Kentucky Commission reviewed the FAC of KU for the six month period ended October 31, 2001. The Kentucky Commission ordered KU to reduce its fuel costs for purposes of calculating its FAC by \$673,000. At issue was the purchase of approximately 102,000 tons of coal from Western Kentucky Energy Corporation, a non-regulated affiliate, for use at KU's Ghent Facility. The Kentucky Commission further ordered that an independent audit be conducted to examine operational and management aspects of KU's fuel procurement functions.

On February 15, 2003, KU experienced a severe ice storm in Lexington, Kentucky, and surrounding service area causing over 140,000 customers to lose power. KU is still in the process of accumulating the costs of the storm. Costs relate to repair of transmission and distribution system, property damage, and significant labor costs, including contractor costs. A portion of the costs may be offset by insurance proceeds.

On March 18, 2003, the Kentucky Commission approved LG&E and KU's joint application for the acquisition of four CTs from an unregulated affiliate, LG&E Capital Corp. The total projected construction cost for the turbines, expected to be available for June 2004 in-service, is \$227.4 million. The requested ownership share of the turbines is 63% for KU and 37% for LG&E.

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Kentucky Utilities Company REPORT OF MANAGEMENT

The management of Kentucky Utilities Company is responsible for the preparation and integrity of the financial statements and related information. These statements have been prepared in accordance with accounting principles generally accepted in the United States applied on a consistent basis and, necessarily, include amounts that reflect the best estimates and judgment of management.

KU's 2002 and 2001 financial statements have been audited by PricewaterhouseCoopers LLP, independent accountants. Management made available to PricewaterhouseCoopers LLP all KU's financial records and related data as well as the minutes of shareholders' and directors' meetings.

Management has established and maintains a system of internal controls that provide reasonable assurance that transactions are completed in accordance with management's authorization, that assets are safeguarded and that financial statements are prepared in conformity with generally accepted accounting principles. Management believes that an adequate system of internal controls is maintained through the selection and training of personnel, appropriate division of responsibility, establishment and communication of policies and procedures and by regular reviews of internal accounting controls by KU's internal auditors. Management reviews and modifies its system of internal controls in light of changes in conditions and operations, as well as in response to recommendations from the internal and external auditors. These recommendations for the year ended December 31, 2002, did not identify any material weaknesses in the design and operation of KU's internal control structure.

In carrying out its oversight role for the financial reporting and internal controls of KU, the Board of Directors meets regularly with KU's independent public accountants, internal auditors and management. The Board of Directors reviews the results of the independent accountants' audit of the financial statements and their audit procedures, and discusses the adequacy of internal accounting controls. The Board of Directors also approves the annual internal auditing program, and reviews the activities and results of the internal auditing function. Both the independent public accountants and the internal auditors have access to the Board of Directors at any time.

Kentucky Utilities Company maintains and internally communicates a written code of business conduct that addresses, among other items, potential conflicts of interest, compliance with laws, including those relating to financial disclosure, and the confidentiality of proprietary information.

S. Bradford Rives
Chief Financial Officer

Kentucky Utilities Company
Louisville, Kentucky
November 12, 2003

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Kentucky Utilities Company and Subsidiary

REPORT OF INDEPENDENT ACCOUNTANTS

To the Shareholders of Kentucky Utilities Company and Subsidiary:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of capitalization, income, retained earnings, cash flows and comprehensive income present fairly, in all material respects, the financial position of Kentucky Utilities Company and Subsidiary (the "Company"), a wholly-owned subsidiary of LG&E Energy Corp., at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. 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 audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit 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, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the financial statements, effective January 1, 2003, the Company adopted EITF No. 02-03, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.

*/s/ PricewaterhouseCoopers LLP
Louisville, Kentucky
January 21, 2003, except for note 1 as to which the date is November 12,
2003*

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