UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2003

Commission File Number 1-14161

KEYSPAN CORPORATION

(Exact name of registrant as specified in its charter)

NEW YORK	**11-3431358**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification no.)
One MetroTech Center, Brooklyn, New York	**11201**
175 East Old Country Road, Hicksville, New York	**11801**
(Address of principal executive offices)	(Zip code)

(718) 403-1000 (Brooklyn)
(516) 755-6650 (Hicksville)
(Registrant's telephone number, including area code)

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Common Stock, $.01 par value	New York Stock Exchange Pacific Stock Exchange
Series AA Preferred Stock, $25 par value	New York Stock Exchange Pacific Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
None
(Title of class)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. X Yes ___ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act) X Yes__ No

As of June 30, 2003, the aggregate market value of the common stock held by non-affiliates (157,824,519 shares) of the registrant was $5,594,879,198 based on the closing price of the New York Stock Exchange on such date, of $35.45 per share. For purposes of this computation, all officers and directors of the registrant are deemed to be affiliates.

As of March 1, 2004, there were 159,844,530 shares of common stock, $.01 par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy Statement dated on or about March 25, 2004 is incorporated by reference into Part III hereof.

KEYSPAN CORPORATION
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PART I

Item 1. *Description of the Business*

Corporate Overview

KeySpan Corporation ("KeySpan"), a New York corporation, is a member of the Standard and Poor's 500 Index and a registered holding company under the Public Utility Holding Company Act of 1935, as amended ("PUHCA"). KeySpan was formed in May 1998, as a result of the business combination of KeySpan Energy Corporation, the parent of The Brooklyn Union Gas Company, and certain businesses of the Long Island Lighting Company ("LILCO"). On November 8, 2000, we acquired Eastern Enterprises ("Eastern"), now known as KeySpan New England, LLC ("KNE"), a Massachusetts limited liability company, which primarily owns Boston Gas Company ("Boston Gas"), Colonial Gas Company ("Colonial Gas") and Essex Gas Company ("Essex Gas"), gas utilities operating in Massachusetts, as well as EnergyNorth Natural Gas, Inc. ("EnergyNorth"), a gas utility operating principally in central New Hampshire. As used herein, "KeySpan," "we," "us" and "our" refers to KeySpan, its six principal gas distribution subsidiaries, and its other regulated and unregulated subsidiaries, individually and in the aggregate.

Under our holding company structure, we have no independent operations and conduct substantially all of our operations through our subsidiaries. Our subsidiaries operate in the following four businesses: Gas Distribution, Electric Services, Energy Services and Energy Investments.

The Gas Distribution segment consists of our six regulated gas distribution subsidiaries, which operate in New York, Massachusetts and New Hampshire and serve approximately 2.5 million customers.

The Electric Services segment consists of subsidiaries that manage the electric transmission and distribution ("T&D") system owned by the Long Island Power Authority ("LIPA"); provide generating capacity and, to the extent required, energy conversion services for LIPA from our approximately 4,200 megawatts of generating facilities located on Long Island; and manage fuel supplies for LIPA to fuel our Long Island generating facilities. The Electric Services segment also includes subsidiaries that own, lease and operate the 2,200 megawatt Ravenswood electric generation facility (the "Ravenswood facility"), located in Queens County in New York City, as well as the 250 megawatt expansion unit at Ravenswood expected to be completed within the next few months.

The Energy Services segment provides energy-related services to customers primarily located within New York, New Jersey, Connecticut, Massachusetts, New Hampshire, Rhode Island and Pennsylvania through various subsidiaries that operate under the following principal two lines of business: (i) home energy services; and (ii) business solutions.

The Energy Investments segment includes: (i) gas exploration and production activities; (ii) domestic pipelines and gas storage facilities; (iii) midstream natural gas processing activities in Canada; and (iv) natural gas pipeline activities in the United Kingdom.

KeySpan's vision is to be the premier energy company in the Northeastern United States. Following the acquisition of Eastern and EnergyNorth in November 2000, KeySpan became the largest gas distribution company in the Northeast and the fifth largest in the United States. KeySpan's increased size and scope is enabling us to provide enhanced cost-effective customer service; to offer our existing customers other services and products by building upon our existing customer relationships; and to capitalize on the above-average growth opportunities for natural gas expansion in the Northeast by expanding our infrastructure, primarily on Long Island and in New England. The key element of our business strategy is the continued focus and growth of our core businesses. We also continue to explore the monetization of some or all of our non-core assets in the Energy Investments segment.

Certain statements contained in this Annual Report on Form 10-K concerning expectations, beliefs, plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are other than statements of historical facts, are "forward-looking statements" within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Without limiting the foregoing, all statements under the captions "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" relating to our future outlook, anticipated capital expenditures, future cash flows and borrowings, pursuit of potential future acquisition opportunities and sources of funding, are forward-looking statements. Such forward-looking statements reflect numerous assumptions and involve a number of risks and uncertainties and actual results may differ materially from those discussed in such statements.

Among the factors that could cause actual results to differ materially are:

- volatility of energy prices of fuel used to generate electricity;
- fluctuations in weather and in gas and electric prices;
- general economic conditions, especially in the Northeast United States;
- our ability to successfully reduce our cost structure and operate efficiently;
- our ability to successfully contract for natural gas supplies required to meet the needs of our customers;
- implementation of new accounting standards;
- inflationary trends and interest rates;
- the ability of KeySpan to identify and make complementary acquisitions, as well as the successful integration of recent and future acquisitions;
- available sources and cost of fuel;
- creditworthiness of counter-parties to derivative instruments and commodity contracts;
- the resolution of certain disputes with LIPA concerning each party's rights and obligations under various agreements;
- retention of key personnel;

- federal and state regulatory initiatives that increase competition, threaten cost and investment recovery, and place limits on the type and manner in which we invest in new businesses and conduct operations;
- the impact of federal and state utility regulatory policies and orders on our regulated and unregulated businesses;
- potential write-down of our investment in natural gas properties when natural gas prices are depressed or if we have significant downward revisions in our estimated proved gas reserves;
- competition in general facing our unregulated Energy Services businesses, including but not limited to competition from other mechanical, plumbing, heating, ventilation and air conditioning, and engineering companies, as well as, other utilities and utility holding companies that are permitted to engage in such activities;
- the degree to which we develop unregulated business ventures, as well as federal and state regulatory policies affecting our ability to retain and operate such business ventures profitably; and
- other risks detailed from time to time in other reports and other documents filed by KeySpan with the Securities and Exchange Commission ("SEC").

For any of these statements, KeySpan claims the protection of the safe harbor for forward-looking information contained in the Private Securities Litigation Reform Act of 1995, as amended. For additional discussion on these risks, uncertainties and assumptions, see Item 1. "Description of the Business," Item 2. "Properties," Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" contained herein.

KeySpan's principal executive offices are located at One MetroTech Center, Brooklyn, New York 11201 and 175 East Old Country Road, Hicksville, New York 11801 and its telephone numbers are (718) 403-1000 (Brooklyn) and (516) 755-6650 (Hicksville). KeySpan makes available free of charge on or through its website, http://www.keyspanenergy.com (Investor Relations section), its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC.

KeySpan has adopted a Code of Ethics applicable to its Chief Executive Officer and Senior Financial Officers, and has revised its Ethical Business Conduct Statement applicable to all directors, officers and employees of the Company in each case as required by recently adopted rules and regulations.

KeySpan's Code of Ethics, Ethical Business Conduct Statement, Corporate Governance Guidelines and Committee Charters can each be found on the Investor Relations section of KeySpan's website (http://www.keyspanenergy.com) and provide information on the framework and high standards set by the Company relating to its corporate governance and business practices. Additionally, these documents are available in print to any shareholder requesting a copy. The Code of Ethics, Ethical Business Conduct Statement, Corporate Governance Guidelines and Committee Charters have all been approved by the Board of Directors and are vital to securing the confidence of KeySpan's shareholders, customers, employees, governmental authorities and the investment community.

Gas Distribution Overview

Our gas distribution activities are conducted by our six regulated gas distribution subsidiaries, which operate in three states in the Northeast: New York, Massachusetts and New Hampshire. We are the fifth largest gas distribution company in the United States and the largest in the Northeast, with approximately 2.5 million customers served within an aggregate service area covering 4,273 square miles. In New York, The Brooklyn Union Gas Company, doing business as KeySpan Energy Delivery New York ("KEDNY") provides gas distribution services to customers in the New York City Boroughs of Brooklyn, Queens and Staten Island; and KeySpan Gas East Corporation doing business as KeySpan Energy Delivery Long Island ("KEDLI") provides gas distribution services to customers in the Long Island Counties of Nassau and Suffolk and the Rockaway Peninsula of Queens County. In Massachusetts, Boston Gas provides gas distribution services in eastern and central Massachusetts; Colonial Gas provides gas distribution services on Cape Cod and in eastern Massachusetts; and Essex Gas provides gas distribution services in eastern Massachusetts. In New Hampshire, EnergyNorth provides gas distribution services to customers principally located in central New Hampshire. Our New England gas companies all do business as KeySpan Energy Delivery New England ("KEDNE").

In New York, there are two separate, but contiguous service territories served by KEDNY and KEDLI, comprising approximately 1,417 square miles, and 1.66 million customers. In Massachusetts, Boston Gas, Colonial Gas and Essex Gas serve three contiguous service territories consisting of 1,934 square miles and approximately 768,000 customers. In New Hampshire, EnergyNorth has a service territory that is contiguous to Colonial Gas' and ranges from within 30 to 85 miles of the greater Boston area. EnergyNorth provides service to approximately 75,000 customers over a service area of approximately 922 square miles. Collectively, KeySpan owns and operates gas distribution, transmission and storage systems that consist of approximately 23,000 miles of gas mains and distribution pipelines.

Natural gas is offered for sale to residential and small commercial customers on a "firm" basis, and to most large commercial and industrial customers on a "firm" or "interruptible" basis. "Firm" service is offered to customers under tariffed schedules or contracts that anticipate no interruptions, whereas "interruptible" service is offered to customers under tariffed schedules or contracts that anticipate and permit interruption on short notice, generally in peak-load seasons or for system reliability reasons. We have restructured our gas supply and capacity contracts to reduce fixed costs and to minimize the risk of stranded costs. We maintain sufficient gas supply and capacity contracts to serve our customers, maintain system reliability and system operations, and to meet our obligation to serve. Over the long term, we intend to minimize our fixed costs by increasing the amount of gas purchased at points within or in close proximity to our market area, which allow us to contract for firm short-haul transportation capacity from these points rather than long-haul transportation capacity from production areas. We also engage in the use of derivative financial instruments from time to time to reduce the cash flow volatility associated with the purchase price for a portion of future natural gas purchases.

Natural gas is available at any time of the year on an interruptible basis, if supply is sufficient and the gas delivery system is operationally adequate. KeySpan actively promotes a competitive retail gas market by making capacity available to retail marketers that are unable to obtain their own capacity and are otherwise not participants of a mandatory capacity assignment program. KeySpan also participates in interstate markets by releasing pipeline capacity or by bundling gas supply and pipeline capacity for "off-system" sales. An "off-system" customer consumes gas at facilities located outside of our service territories by connecting to our facilities or another transporter's facilities at a point of delivery agreed to by us and the customer.

KeySpan purchases natural gas for sale to customers under both long-and short-term supply contracts, as well as on the spot market, and utilizes its firm transportation contracts to transport the gas. KeySpan also contracts for firm capacity in natural gas underground storage facilities, in addition to winter peaking supplies.

KeySpan sells gas to firm gas customers at its cost for such gas, plus a charge designed to recover the costs of distribution (including a return of and a return on capital invested in our distribution facilities). We share with our firm gas customers net revenues (operating revenues less the cost of gas and associated revenue taxes) from off-system sales and capacity release transactions. Further, net revenues from tariff gas balancing services and certain interruptible on-system sales are refunded, for most of our subsidiaries, to firm customers subject to certain sharing provisions.

Our gas operations can be significantly affected by seasonal weather conditions. Annual revenues are substantially realized during the heating season as a result of higher sales of gas due to cold weather. Accordingly, operating results historically are most favorable in the first and fourth calendar quarters. KEDNY and KEDLI each operate under utility tariffs that contain a weather normalization adjustment that significantly offsets variations in firm net revenues due to fluctuations in weather. However, the tariffs for our four KEDNE gas distribution companies do not contain such a weather normalization adjustment and, therefore, fluctuations in seasonal weather conditions between years may have a significant effect on results of operations and cash flows for these four subsidiaries. We utilize weather derivatives for KEDNE to mitigate variations in firm net revenues due to fluctuations in weather.

For further information and statistics regarding our Gas Distribution segment, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, "Gas Distribution."

New York Gas Distribution System - KEDNY and KEDLI Supply and Storage

KEDNY and KEDLI have firm long-term contracts for the purchase of transportation and underground storage services. Gas supplies are purchased under long and short-term firm contracts, as well as on the spot market. Gas supplies are transported by interstate pipelines from domestic and Canadian supply basins. Peaking supplies are available to meet system requirements on the coldest days of the winter season.

Peak-Day Capability. The design criteria for the New York gas system assumes an average temperature of 0ºF for peak-day demand. Under such criteria, we estimate that the requirements to supply our firm gas customers would amount to approximately 2,053 MDTH (one MDTH equals 1,000 DTH or 1 billion British Thermal Units) of gas for a peak-day during the 2003/04 winter season and that the gas available to us on such a peak-day amounts to approximately

2,076 MDTH. As of January 20, 2004, the 2003/04 winter peak-day throughput to our New York customers was 1,804 MDTH, which occurred on January 15, 2004 at an average temperature of 7 degrees F, representing 87% of our peak-day capability. Our New York firm gas peak-day capability is summarized in the following table:

Source	MDTH per day	% of Total
Pipeline	794	38%
Underground Storage	778	38%
Peaking Supplies	504	24%
Total	2,076	100%

Pipelines. Our New York-based gas distribution utilities purchase natural gas for sale under contracts with suppliers with natural gas located in domestic and Canadian supply basins and arrange for its transportation to our facilities under firm long-term contracts with interstate pipeline companies. For the 2003/04 winter, approximately 75% of our New York natural gas supply was available from domestic sources and 25% from Canadian sources. We have available under firm contract 794 MDTH per day of year-round and seasonal pipeline transportation capacity. Major providers of interstate pipeline capacity and related services to us include: Transcontinental Gas Pipe Line Corporation ("Transco"), Texas Eastern Transmission Corporation ("Tetco"), Iroquois Gas Transmission System, L.P. ("Iroquois"), Tennessee Gas Pipeline Company ("Tennessee"), Dominion Transmission Incorporated ("Dominion"), and Texas Gas Transmission Company.

Underground Storage. In order to meet winter demand in our New York service territories, we also have long-term contracts with Transco, Tetco, Tennessee, Dominion, Equitrans, Inc., and Honeoye Storage Corporation ("Honeoye"), for underground storage capacity of 59,058 MDTH and 778 MDTH per day of maximum deliverability.

Peaking Supplies. In addition to the pipeline and underground storage supply, we supplement our winter supply portfolio with peaking supplies that are available on the coldest days of the year to economically meet the increased requirements of our heating customers. Our peaking supplies include: (i) two liquefied natural gas ("LNG") plants; and (ii) peaking supply contracts with five dual fuel power producers located in our franchise areas. For the 2002/03 winter season, we had the capability to provide a maximum peak-day supply of 504 MDTH on excessively cold days. The LNG plants provided us with peak day capacity of 394 MDTH and winter season availability of 2,053 MDTH. The peaking supply contracts with the five duel fuel power producers provided us with peak day capacity of 110 MDTH and winter season availability of 3,349 MDTH.

Gas Supply Management. We have an agreement with Coral Resources, L.P. ("Coral"), a subsidiary of Shell Oil Company, under which Coral assists in the origination, structuring, valuation and execution of energy-related transactions on behalf of KEDNY and KEDLI which expires on March 31, 2006.

Gas Costs. The current gas rate structure of each of these companies includes a gas adjustment clause pursuant to which variations between actual gas costs incurred and gas costs billed are deferred and subsequently refunded to or collected from firm customers.

Deregulation. Regulatory actions, economic factors and changes in customers and their preferences continue to reshape our gas operations. A number of customers currently purchase their gas supplies from natural gas marketers and then contract with us for local transportation, balancing and other unbundled services. In addition, our New York gas distribution companies release firm capacity on our interstate pipeline transportation contracts to natural gas marketers to ensure the marketers' gas supply is delivered on a firm basis and in a reliable manner. As of January 1, 2004, approximately 105,429 gas customers on the New York Gas Distribution System are purchasing their gas from marketers. However, net gas revenues are not significantly affected by customers opting to purchase their gas supply from other sources since delivery rates charged to transportation customers generally are the same as delivery rates charged to sales service customers.

New England Gas Distribution Systems – Supply and Storage

KEDNE has firm long-term contracts for the purchase of transportation and underground storage services. Gas supplies are purchased under long and short-term firm contracts, as well as on the spot market. Gas supplies are transported by interstate pipelines from domestic and Canadian supply basins. In addition, peaking supplies, principally liquefied natural gas, are available to meet system requirements during the winter season.

Peak-Day Capability. The design criteria for our New England gas systems assumes a level of 78 effective degree days for peak-day demand. Under such criteria, KEDNE estimates that the requirements to supply their firm gas customers would amount to approximately 1,281 MDTH of gas for a peak-day during the 2003/2004 winter season. The gas available to KEDNE on such a peak-day amounts to 1,402 MDTH. KEDNE estimates an additional 105 MDTH of on-system throughput on behalf of its transportation-only customers for a total peak day throughput estimate of 1,386 MDTH.

The highest daily throughput, which includes both firm sales and firm transportation, to our New England customers was 1,421 MDTH, which occurred on January 15, 2004 at a level of 80 effective degree days. The total throughput of 1,421 MDTH exceeded the design day throughput estimate by two and one half percent (2.5%). KEDNE has sufficient gas supply available to meet the requirements of their firm gas customers for the 2003/2004 winter season. The firm gas supply peak day capability of KEDNE for its firm customers is summarized in the following table:

Source	MDTH per day	% of Total
Pipeline	486	35
Underground Storage	261	19
Peaking Supplies	655	47
Total	1402	100

Pipelines. Our New England based gas distribution utilities purchase natural gas for sale under contracts with suppliers with natural gas located in domestic and Canadian supply basins and arrange for transportation to their facilities under firm long-term contracts with interstate pipeline companies. Major providers of interstate pipeline capacity and related services to the KEDNE companies include: Tetco, Iroquois, Maritimes and Northeast Pipelines, Tennessee, Algonquin Gas Transmission Company and Portland Natural Gas Transmission System.

Underground Storage. KEDNE has available under firm contract 747 MDTH per day of year-round and seasonal transportation and underground storage capacity to their facilities in New England. KEDNE has long-term contracts with Tetco, Tennessee, Dominion, National Fuel Gas Supply Corporation and Honeoye for underground storage capacity of 23,280 MDTH and 261 MDTH per day of maximum deliverability.

Peaking Supplies. The KEDNE gas supply portfolio is supplemented with peaking supplies that are available on the coldest days throughout the winter season in order to economically meet the increased requirements of our heating customers. Peaking supplies include gas provided by both LNG and propane air plants located within the distribution system, as well as two leased facilities located in Providence, Rhode Island and Everett, MA. For the 2003/2004 winter season, on a peak-day, KEDNE has access to 655 MDTH of peaking supplies, 47% of peak-day supply.

Gas Supply Management. Since April 1, 2003 the New England based gas distribution subsidiaries have been operating under a portfolio management contract with Entergy Koch Trading, LP ("EKT"). EKT provides the majority of the city gate supply requirements to the four New England gas distribution companies (Boston Gas, Colonial Gas, Essex Gas and Energy North) at market prices and manages upstream capacity, underground storage and supply contracts.

Gas Costs. Fluctuations in gas costs have little impact on the operating results of the KEDNE companies since the current gas rate structure for each of the companies include gas adjustment clauses pursuant to which variations between actual gas costs incurred and gas costs billed are deferred and subsequently refunded to or collected from customers.

For additional information concerning the gas distribution segment, see the discussion in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – "Gas Distribution" contained herein.

Electric Services Overview

We are the largest electric generator in New York State. Our subsidiaries own and operate 5 large generating plants and 10 smaller facilities which are comprised of 57 generating units in Nassau and Suffolk Counties on Long Island and the Rockaway Peninsula in Queens. In addition, we own, lease and operate the Ravenswood Generating Station located in Queens County, which is the largest generating facility in New York City. Ravenswood is comprised of 3 large steam-generating units and 17 gas turbine generators. A 250MW expansion at our Ravenswood facility has been qualified to participate in the capacity market administered by the

New York Independent System Operator as of April 1, 2004 (the "Ravenswood Expansion Project") and we operate and maintain a 55 MW gas turbine unit in Greenport, Long Island under an agreement with Global Commons Greenport.

As more fully described below, we: (i) provide to LIPA all operation, maintenance and construction services and significant administrative services relating to the Long Island electric transmission and distribution ("T&D") system through a management services agreement (the "MSA"); (ii) supply LIPA with generating capacity, energy conversion and ancillary services from the Long Island units through a power supply agreement (the "PSA") and other long-term agreements to provide LIPA with approximately two thirds of its customers energy needs; and (iii) manage all aspects of the fuel supply for our Long Island generating facilities, as well as all aspects of the capacity and energy owned by or under contract to LIPA through an energy management agreement (the "EMA"). We also purchase energy, capacity and ancillary services in the open market on LIPA's behalf under the EMA. Each of the MSA, PSA and EMA became effective on May 28, 1998 and are collectively referred to herein as the "LIPA Agreements." Additional electric capacity and energy are supplied under power purchase agreements with LIPA from four gas turbine units installed in 2002 at our Glenwood and Port Jefferson sites. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation – "Electric Services – Revenue Mechanisms" for a further discussion of these matters.

Generating Facility Operations

In June 1999, we acquired the 2,200 megawatt Ravenswood facility located in New York City from Consolidated Edison Company of New York, Inc. ("Consolidated Edison") for approximately $597 million. In order to reduce our initial cash requirements to finance this acquisition, we entered into an arrangement with an unaffiliated variable interest entity through which we lease a portion of the Ravenswood facility. Under the arrangement, the variable interest entity acquired a portion of the facility directly from Consolidated Edison and leased it to our wholly owned subsidiary. We have guaranteed all payment and performance obligations of our subsidiary under the lease. The lease ("Master Lease") relates to approximately $425 million of the acquisition cost of the facility, which is the amount of debt that would have been recorded on our Consolidated Balance Sheet had the variable interest entity not been utilized and instead conventional debt financing been employed. The initial term of the Master Lease expires on June 20, 2004 and may be extended until June 20, 2009. In June 2004, we have the right to: (i) either purchase the facility for the original acquisition cost of $425 million, plus the present value of the lease payments that would otherwise have been paid through June 2009; (ii) terminate the Master Lease and dispose of the facility; or (iii) otherwise extend the Master Lease to 2009. If the Master Lease is terminated in 2004, KeySpan has guaranteed an amount generally equal to 83% of the residual value of the original cost of the property, plus the present value of the lease payments that would have otherwise been paid through June 20, 2009. KeySpan intends to extend the Master Lease for the forseeable future. (See discussion concerning the Financial Accounting Standards Board issued Interpretation No. 46 in Note 7 to the Consolidated Financial Statements, "Contractual Obligations, Financial Guarantees and Contingencies."

The Ravenswood facility sells capacity, energy and ancillary services into the New York Independent System Operator ("NYISO") energy market at market-based rates, subject to mitigation. The plant has the ability to provide approximately 25% of New York City's capacity requirements and is a strategic asset that is available to serve residents and businesses in New York City. In addition, KeySpan intends to enter into a sale/leaseback transaction to finance a significant portion of the costs related to the Ravenswood Expansion Project. For further details on this proposed transaction, see Note 15 to the Consolidated Financial Statements - "Subsequent Events."

The New York State competitive wholesale market for capacity, energy and ancillary services administered by the NYISO is still evolving and the Federal Energy Regulatory Commission ("FERC") has adopted several price mitigation measures which are subject to rehearing and possible judicial review. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation – "Regulatory Issues and Competitive Environment" for a further discussion of these matters.

Forty-five of our seventy-seven generating units are dual fuel units. In recent years, we have reconfigured several of our facilities to enable them to burn either natural gas or oil, thus enabling us to switch periodically between fuel alternatives based upon cost and seasonal environmental requirements. Through other innovative technological approaches, we increased installed capacity in our generating facilities by 80 MW, and we instituted a program to reduce nitrogen oxides for improved environmental performance.

The following table indicates the 2003 summer capacity of all of our steam generation facilities and gas turbine ("GT") units as reported to the NYISO:

Location of Units	*Description*	*Fuel*	*Units*	*MW*
Long Island City	Steam Turbine	Dual*	3	1,765
Northport, L.I.	Steam Turbine	Dual*	4	1,529
Port Jefferson, L.I.	Steam Turbine	Dual*	2	388
Glenwood, L.I.	Steam Turbine	Gas	2	232
Island Park, L.I.	Steam Turbine	Dual*	2	391
Far Rockaway, L.I.	Steam Turbine	Dual*	1	110
Long Island City	GT Units	Dual*	17	454
Throughout L.I.	GT Units	Gas	4	160
Throughout L.I.	GT Units	Dual*	12	311
Throughout L.I.	GT Units	Oil	30	1,093
TOTAL			77	6,433

*Dual - Oil (#2 oil, #6 residual oil) or kerosene, and natural gas.

In January 2002, we filed an application for approval with the New York State Siting Board on Electric Generation and Environment ("Siting Board") for a 250 MW combined cycle plant in Melville, NY. In February 2003, the Presiding Examiners issued a Recommended Decision recommending that the Siting Board issue a Certificate of Environmental Capability and Public Need for the project, and on May 8, 2003 the Siting Board issued the certificate. In 2003, we formed a joint venture with American National Power, Inc. ("ANP") for the purpose of jointly submitting a proposal in repsonse to a request for proposals by LIPA for additional generating resources. The response proposed the construction of two 250 MW plants, one at the Melville site and another at a site in the town of Brookhaven in Long Island which also received a certificate from the Siting Board. If successful in negotiating a power purchase agreement with LIPA, the ANP joint venture will commence construction of the plant. Otherwise, we may seek other opportunities to enter into a long-term agreement for the sale of capacity, energy and ancillary services. In addition, as part of our growth strategy, we continually evaluate the possible acquisition or development of additional generating facilities in the Northeast. However, we are unable to predict when or if such facilities will be acquired or constructed and the effect any such acquired facilities will have on our financial condition, results of operations or cash flows.

LIPA Agreements

LIPA is a corporate municipal instrumentality and a political subdivision of the State of New York. On May 28, 1998, certain of LILCO's business units were merged with KeySpan and LILCO's common stock and remaining assets were acquired by LIPA. At the time of this transaction, three major long-term service agreements were also executed between KeySpan and LIPA (collectively, the "LIPA Agreements"). Under the agreements and subsequent Power Purchase Agreements, KeySpan provides: 4,214 MW of power generation capacity and energy conversion services; operation, maintenance and capital improvement services for LIPA's transmission and distribution system; and energy management services.

Power Supply Agreement. A KeySpan subsidiary sells to LIPA all of the capacity and, to the extent requested, energy conversion services from our existing Long Island based oil and gas-fired generating plants. Sales of capacity and energy conversion services are made under rates approved by FERC. Under the terms of the PSA, rates will be reestablished for the contract year commencing January 1, 2004 by recalculating the revenue requirement underlying those rates. A rate filing reflecting the recalculated revenue requirement was submitted to FERC on October 31, 2003 and on December 30, 2003, FERC issued an order accepting, in part, the rates subject to refund pending settlement discussions and hearings. We are unable to predict the outcome of those proceedings at this time. Rates charged to LIPA include a fixed and variable component. The variable component is billed to LIPA on a monthly basis and is dependent on the number of megawatt hours dispatched. LIPA has no obligation to purchase energy conversion services from us and is able to purchase energy or energy conversion services on a least-cost basis from all available sources consistent with existing interconnection limitations of the T&D system. The PSA provides incentives and penalties that can total $4 million annually for the maintenance of the output capability and the efficiency of the generating facilities. In 2003, we earned $4 million in incentives under the PSA.

The PSA runs for a term of 15 years. The PSA is renewable for an additional 15 years on similar terms at LIPA's option. However, the PSA provides LIPA the option of electing to reduce or "ramp-down" the capacity it purchases from us in accordance with agreed-upon schedules. In years 7 through 10 of the PSA, if LIPA elects to ramp-down, we are entitled to receive payment for 100% of the present value of the capacity charges otherwise payable over the remaining term of the PSA. If LIPA ramps-down the generation capacity in years 11 through 15 of the PSA, the capacity charges otherwise payable by LIPA will be reduced in accordance with a formula established in the PSA. If LIPA exercises its ramp-down option, KeySpan may use any capacity released by LIPA to bid on new LIPA capacity requirements or to replace other ramped-down capacity. If we continue to operate the ramped-down capacity, the PSA requires us to use reasonable efforts to market the capacity and energy from the ramped-down capacity and to share any profits with LIPA. The PSA will be terminated in the event that LIPA exercises its right to purchase, at fair market value, all of the Long Island generating facilities pursuant to the Generation Purchase Rights Agreement discussed in greater detail below.

We also have an inventory of sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") emission allowances that may be sold to third party purchasers. The amount of allowances varies from year to year relative to the level of emissions from the Long Island generating facilities, which is greatly dependent on the mix of natural gas and fuel oil used for generation and the amount of purchased power that is imported onto Long Island. In accordance with the PSA, 33% of emission allowance sales revenues attributable to the Long Island generating facilities is retained by KeySpan and the other 67% is credited to LIPA. LIPA also has a right of first refusal on any potential emission allowance sales of the Long Island generating facilities. Additionally, KeySpan voluntarily entered into a memorandum of understanding with the New York State Department of Environmental Conservation ("DEC"), which memorandum prohibits the sale of SO_2 allowances into certain states and requires the purchaser to be bound by the same restriction, which may marginally affect the market value of the allowances.

Management Services Agreement. Under the MSA, we perform day-to-day operation and maintenance services and capital improvements for LIPA's transmission and distribution system, including, among other functions, transmission and distribution facility operations, customer service, billing and collection, meter reading, planning, engineering, and construction, all in accordance with policies and procedures adopted by LIPA. KeySpan furnishes such services as an independent contractor and does not have any ownership or leasehold interest in the transmission and distribution system.

In exchange for providing these services, we are reimbursed for our budgeted costs and entitled to earn an annual management fee of $10 million and may also earn certain cost-based incentives, or be responsible for certain cost-based penalties. The incentives provide for us to retain 100% of the first $5 million of budget underruns and 50% of any additional budget underruns up to 15% of the total cost budget. Thereafter, all savings accrue to LIPA. The penalties require us to absorb any total cost budget overruns up to a maximum of $15 million in any contract year.

In addition to the foregoing cost-based incentives and penalties, we are eligible for performance-based incentives for performance above certain threshold target levels and subject to disincentives for performance below certain other threshold levels, with an intermediate band of performance in which neither incentives nor disincentives will apply, for system reliability, worker safety, and customer satisfaction. In 2003, we earned $7.2 million in non-cost performance incentives.

The MSA was originally set to expire on May 28, 2006, but was extended through December 31, 2008. The MSA was extended in exchange for an extension of the option period under the Generation Purchase Rights Agreement as more fully described in the discussion on "Generation Purchase Rights Agreement" below.

Energy Management Agreement. Pursuant to the EMA, KeySpan (i) procures and manages fuel supplies for LIPA to fuel our Long Island generating facilities acquired from LILCO in 1998; (ii) performs off-system capacity and energy purchases on a least-cost basis to meet LIPA's needs; and (iii) makes off-system sales of output from the Long Island generating facilities and other power supplies either owned or under contract to LIPA. LIPA is entitled to two-thirds of the profit from any off-system electricity sales arranged by us. The term for the fuel supply service provided in (i) above is fifteen years, expiring May 28, 2013, and the term for the off-system purchases and sales services provided in (ii) and (iii) above is eight years, expiring May 28, 2006.

In exchange for these services, we earn an annual fee of $1.5 million, plus an allowance for certain costs incurred in performing services under the EMA. The EMA further provides incentives and disincentives up to $5 million annually for control of the cost of fuel and electricity purchased on behalf of LIPA. In 2003, we earned EMA incentives in an aggregate of $5 million.

Generation Purchase Rights Agreement. Under the Generation Purchase Rights Agreement ("GPRA"), LIPA had the right for a one-year period, beginning May 28, 2001, to acquire all of our Long Island based generating assets formerly owned by LILCO at fair market value at the time of the exercise of such right. By agreement dated March 29, 2002, LIPA and KeySpan amended the GPRA to provide for a new six-month option period ending on May 28, 2005. The other terms of the option reflected in the GPRA remain unchanged.

The GPRA and MSA extensions were the result of an initiative established by LIPA to work with KeySpan and others to review Long Island's long-term energy needs. We will work with LIPA to jointly analyze new energy supply options including re-powering existing plants, renewable energy technologies, distributed generation, conservation initiatives and retail competition. The extension also allows both LIPA and us to explore alternatives to the GPRA including the sale of some of our currently existing Long Island generation plants to LIPA, or the sale of some or all of these plants to other private operators.

Other Rights. Pursuant to other agreements between LIPA and us, certain future rights have been granted to LIPA. Subject to certain conditions, these rights include the right for 99 years to lease or purchase, at fair market value, parcels of land and to acquire unlimited access to, as well as appropriate easements at, the Long Island generating facilities for the purpose of constructing new electric generating facilities to be owned by LIPA or its designee. Subject to this right granted to LIPA, KeySpan has the right to sell or lease property on or adjoining the Long Island generating facilities to third parties. In addition, LIPA has acquired a parcel of land at the site of the former Shoreham Nuclear Power Station site for the terminus of a transmission cable under Long Island Sound and other generating facilities.

We own the common plant (such as administrative office buildings and computer systems) formerly owned by LILCO and recover an allocable share of the carrying costs of such plant through the MSA. KeySpan has agreed to provide LIPA, for a period of 99 years, the right to enter into leases at fair market value for common plant or sub-contract for common services which it may assign to a subsequent manager of the transmission and distribution system. We have also agreed: (i) for a period of 99 years not to compete with LIPA as a provider of transmission or distribution service on Long Island; (ii) that LIPA will share in synergy (*i.e.*, efficiency) savings over a 10-year period attributed to the May 28, 1998 transaction which resulted in the formation of KeySpan (estimated to be approximately $1 billion), which savings are incorporated into the cost structure under the LIPA Agreements; and (iii) generally not to commence any tax certiorari case (until termination of the PSA) challenging certain property tax assessments relating to the former LILCO Long Island generating facilities.

Guarantees and Indemnities. We have entered into agreements with LIPA to provide for the guarantee of certain obligations, indemnification against certain liabilities and allocation of responsibility and liability for certain pre-existing obligations and liabilities. In general, liabilities associated with the LILCO assets transferred to KeySpan, have been assumed by KeySpan; and liabilities associated with the assets acquired by LIPA, are borne by LIPA, subject to certain specified exceptions. We have assumed all liabilities arising from all manufactured gas plant ("MGP") operations of LILCO and its predecessors, and LIPA has assumed certain liabilities relating to the former LILCO Long Island generating facilities and all liabilities traceable to the business and operations conducted by LIPA after completion of the 1998 KeySpan/LILCO transaction. An agreement also provides for an allocation of liabilities which relates to the assets that were common to the operations of LILCO and/or shared services and are not traceable directly to either the business or operations conducted by LIPA or KeySpan. In addition, costs incurred by KeySpan for liabilities for asbestos exposure arising from the activities of the generating facilities previously owned by LILCO are recoverable from LIPA through the Power Supply Agreement between LIPA and KeySpan.

For additional information concerning the Electric Services segment, see the discussion in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – "Electric Services" contained herein.

Energy Services Overview

The Energy Services segment includes companies that provide energy-related services to customers primarily located within the New York City metropolitan area including New Jersey and Connecticut, as well as Rhode Island, Pennsylvania, Massachusetts and New Hampshire through the following two lines of business: (i) Home Energy Services, which provides residential customers with installation, service and maintenance of energy systems and appliances, as well as the retail marketing of electricity to commercial customers; and (ii) Business Solutions, which provides plumbing, heating, ventilation, air conditioning and mechanical services, as well as operation and maintenance, design, engineering and consulting services to commercial and industrial customers. On May 1, 2003, KeySpan's gas and electric marketing subsidiary, KeySpan Energy Services, assigned a substantial portion of its retail natural gas customers, consisting mostly of residential and small commercial customers, to ECONnergy Energy Co., Inc. ("ECONnergy"). ECONnergy is one of the largest deregulated energy service companies in the Northeast. KeySpan Energy Services is continuing its electric marketing activities.

The Energy Services segment has more than 2,700 employees and 200,000 service contracts, and is the number one oil to gas conversion contractor in New York and New England. KeySpan's Energy Services subsidiaries compete with local, regional and national mechanical contracting, HVAC, plumbing, engineering, and independent energy companies, in addition to electric utilities, independent power producers and local distribution companies.

Competition is based largely upon pricing, availability and reliability of supply, technical and financial capabilities, regional presence, experience and customer service.

In 2001, we discontinued the general contracting activities related to the former Roy Kay companies with the exception of work to be completed on existing contracts, based upon our view that the general contracting business was not a core competency of these companies. As a result of our evaluation of the Energy Services business undertaken during 2001, we decided to set certain limitations on the types of new general contracting activities in which our contracting subsidiaries may engage. We also installed senior management personnel who, among other things, have reviewed and continue to review and focus on our overall strategy of these businesses.

For additional information concerning the Energy Services segment, see the discussion in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – "Energy Services" contained herein.

Energy Investments Overview

We are also engaged in Energy Investments which include: (i) gas exploration and production activities; (ii) domestic pipelines and gas storage facilities; (iii) midstream natural gas processing activities in Canada; (iv) natural gas pipeline activities in the United Kingdom; and (v) certain other domestic energy-related investments, such as the transportation by truck of liquid natural gas and new fuel cell technologies.

Gas Exploration and Production

KeySpan is engaged in the exploration for and production of domestic natural gas and oil through our equity interest in The Houston Exploration Company ("Houston Exploration") and through our wholly owned subsidiary, KeySpan Exploration and Production, LLC ("KeySpan Exploration"). Houston Exploration was organized by KEDNY in 1985 to conduct natural gas and oil exploration and production activities. It completed an initial public offering in 1996 and its shares are currently traded on the New York Stock Exchange under the symbol "THX." On February 26, 2003, Houston Exploration issued 3 million shares of its common stock, the net proceeds of which were used to repurchase 3 million shares of common stock owned by us. As a result of the repurchase, our ownership interest in Houston Exploration was reduced from approximately 66% to the current level of approximately 55%. This reduction in our ownership interest is in line with our strategy of monetizing or divesting certain non-core assets, which include investment in oil and gas exploration and production assets. At March 1, 2004, Houston Exploration's aggregate market capitalization was approximately $1.224 billion (based upon the closing price on the New York Stock Exchange on March 1, 2004 of $38.75 per share). At March 1, 2004, Houston Exploration had approximately 31,587,637 shares of common stock, $0.01 par value, outstanding.

KeySpan Exploration is engaged in a joint venture with Houston Exploration to explore for natural gas and oil. Houston Exploration contributed all of its undeveloped offshore leases to the joint venture for a 55% working interest and KeySpan Exploration acquired a 45% working interest in all prospects to be drilled by the joint venture. Effective 2001, the joint venture was modified to reflect that KeySpan Exploration would only participate in the development of wells that had previously been drilled and not participate in future exploration prospects. In line with our stated strategy of exploring the monetization or divestiture of certain non-core assets, in October 2002, we sold a portion of our assets in the joint venture drilling program to Houston Exploration.

Our gas exploration and production subsidiaries focus their operations offshore in the Gulf of Mexico and onshore in South Texas, South Louisiana, the Arkoma Basin, East Texas and West Virginia. The geographic focus of these operations enables our subsidiaries to manage a comparatively large asset base with relatively few employees and to add and operate production at relatively low incremental costs. Our gas exploration and production subsidiaries seek to balance their offshore and onshore activities so that the lower risk and more stable production typically associated with onshore properties complement the high potential exploratory projects in the Gulf of Mexico by balancing risk and reducing volatility. Houston Exploration's business strategy is to seek to continue to increase reserves, production and cash flow by pursuing internally generated prospects, primarily in the Gulf of Mexico, by conducting development and exploratory drilling on our offshore and onshore properties and by making selective opportune acquisitions.

Offshore Properties. Our interests in offshore properties are located in the shallow waters of the Outer Continental Shelf of the Gulf of Mexico. Our interests in key producing properties are located in the western and central Gulf of Mexico and include the Mustang Island, High Island, East Cameron, Vermilion and South Timbalier areas. We hold interests in 86 blocks in federal and state waters, of which 42 are developed. Through our subsidiaries, we operate 29 of our developed blocks, which accounted for approximately 75% of our interests in offshore production during 2003. We have a total of 37 platforms and production caissons of which we operate 27. Since its inception in 1999, the joint venture participated in 28 wells, 23 of which were successful -- 17 exploratory and six development. During 2002, we drilled ten offshore wells, nine of which were successful, representing a success rate of 90%. Of the successful wells drilled, six were exploratory and three were development. The joint venture participated in four of the 2002 wells, two exploratory and two development, all of which were successful.

Onshore Properties. Our interests in South Texas properties are concentrated in the Charco, Haynes and South Trevino Fields of Zapata County; the Alexander, Hubbard and South Laredo Fields of Webb County; and the North East Thompsonville Field in Jim Hogg County. We own interests in 562 producing wells, 450 of which are operated by our subsidiaries. Our interests in Arkoma Basin properties are located in two primary areas: the Chismville/Massard Field located in Logan and Sebastian Counties of Arkansas and the Wilburton and Panola Fields located in Latimer County, Oklahoma. We own working interests in 252 producing natural gas wells, of which we operate 131. Other Onshore properties are concentrated in three areas: South Louisiana, West Virginia and East Texas. On a combined basis, we own working interests in 708 producing wells, 653 of which we operate. During 2002, we drilled 87 onshore wells, 75 of which were successful, representing a success rate of 86%. Of the successful wells drilled, 54 were drilled in South Texas and 21 were drilled in the Arkoma Basin. Of the 75 successful wells drilled, 73 were development and two were exploratory.

For additional information concerning the gas exploration and production segment, see the discussion on "Gas Exploration and Production" in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and for information with respect to net proved reserves, production, productive wells and acreage, undeveloped acreage, drilling activities, present activities and drilling commitments, see Note 17 to the Consolidated Financial Statements, "Supplemental Gas and Oil Disclosures," included herein.

Domestic Pipelines and Gas Storage Facilities

We also own an approximate 20% interest in Iroquois Gas Transmission System LP, the partnership that owns a 412-mile pipeline that currently transports 1,236 MDTH of Canadian gas supply daily from the New York-Canadian border to markets in the Northeastern United States. KeySpan is also a shipper on Iroquois and currently transports up to 137 MDTH of gas per day.

We are also participating in the Islander East Pipeline Company LLC ("Islander East"), an interstate pipeline joint venture with Duke Energy Corporation. The joint venture involves the construction, ownership and operation of a 50 mile natural gas pipeline that will transport 260 MDTH of gas supply daily from Nova Scotia, Canada to growing markets in Connecticut, New York City and Long Island, New York. Increasing gas transmission capacity is necessary to meet the increased demand for natural gas in the Northeast, which coincides with the growth strategy of our Gas Distribution business. Applications for all necessary regulatory authorizations were filed in 2000 and 2001. To date, Islander East has received a final certificate from the Federal Energy Regulatory Commission ("FERC") and all necessary permits from the State of New York. However, the State of Connecticut has denied Islander East's application for a coastal zone management permit and a permit under Section 401 of the Clean Water Act. Islander East has reinstated its appeal of the State of Connecticut's determination on the coastal zone management issue to the United States Department of Commerce and is evaluating its legal and other options with respect to the Section 401 issue. Once in service, the pipeline is expected to transport up to 260,000 DTH daily to the Long Island and New York City energy markets, enough natural gas to heat 600,000 homes. The pipeline will also allow KeySpan to diversify the geographic sources of its gas supply. However, we are unable to predict when or if all regulatory approvals required to construct this pipeline will be obtained. Various options for the financing of pipeline construction are currently being evaluated. At December 31, 2003, total expenditures associated with the siting and permitting of the Islander East pipeline were $14.9 million.

We also have equity investments in two gas storage facilities in the State of New York: Honeoye Storage Corporation and Steuben Gas Storage Company. We own a 52% interest in Honeoye, an underground gas storage facility which provides up to 4.8 billion cubic feet of storage service to New York and New England. Additionally, we own 34% of a partnership that has a 50% interest in the Steuben facility that provides up to 6.2 billion cubic feet of storage service to New Jersey and Massachusetts.

On December 12, 2002, we acquired Algonquin LNG, LP, the owner and operator of a 600,000 barrel liquefied natural gas ("LNG") storage and receiving facility located in Providence, Rhode Island, from Duke Energy. Boston Gas Company is the facility's largest customer and contracts for more than half of its storage. The facility, renamed KeySpan LNG, LP, is regulated by FERC. In a joint initiative with BG LNG Services, KeySpan plans to upgrade the KeySpan LNG facility to accept marine deliverables and to triple vaporization (or regasification capacity). Pending regulatory approvals, the facility could be ready to accept marine deliverables by late 2005.

Our investments in domestic pipelines and gas storage facilities are complimentary to our Gas Distribution and Electric Services businesses in that they provide energy infrastructure to support the growth of these businesses and, therefore, we will continue to pursue these opportunities.

Midstream Natural Gas Processing Activities in Canada

During the year, we sold 39.09% of our interest in KeySpan Canada, a company with natural gas processing plants and gathering facilities located in Western Canada. In February 2004, we entered into an agreement to sell an additional 35.91% of our interest in KeySpan Canada. Following the closing of this additional sale of our interest, currently scheduled for early April 2004, we will own 25% of KeySpan Canada. The assets include interests in 14 processing plants and associated gathering systems that can process approximately 1.5 BCFe of natural gas daily, and provide associated natural gas liquids fractionation. Additionally, we sold our 20% interest in Taylor NGL LP that owns and operates two extraction plants also in Canada, one located in British Columbia, and one in Alberta, Canada. We consider our Canadian operations to be non-core assets and we continue to evaluate strategies to divest or monetize these assets.

Natural Gas Distribution and Pipeline Activities in the United Kingdom

We own a 50% interest in Premier Transmission Limited, an 84-mile pipeline to Northern Ireland from southwest Scotland that has planned transportation capacity of approximately 300 MDTH of gas supply daily to markets in Northern Ireland. KeySpan considers this a non-core asset and is evaluating the possible divestiture or monetization. In December, 2003, the company sold its interest in Phoenix Natural Gas Limited, a gas distribution system serving the City of Belfast, Northern Ireland.

For additional information concerning the Energy Investments segment, see the discussion on "Energy Investments" in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations contained herein.

Environmental Matters Overview

KeySpan's ordinary business operations subject it to regulation in accordance with various federal, state and local laws, rules and regulations dealing with the environment, including air, water, and hazardous substances. These requirements govern both our normal, ongoing operations and the remediation of impacted properties historically used in utility operations. Potential liability associated with our historical operations may be imposed without regard to fault, even if the activities were lawful at the time they occurred.

Except as set forth below, or in Note 7 to the Consolidated Financial Statements "Contractual Obligations and Contingencies - Environmental Matters," no material proceedings relating to environmental matters have been commenced or, to our knowledge, are contemplated by any federal, state or local agency against KeySpan, and we are not a defendant in any material litigation with respect to any matter relating to the protection of the environment. We believe that our operations are in substantial compliance with environmental laws and that requirements imposed by existing environmental laws are not likely to have a material adverse impact upon us. We are also pursuing claims against insurance carriers and potentially responsible parties which seek the recovery of certain environmental costs associated with the investigation and remediation of contaminated properties. We believe that investigation and remediation costs prudently incurred at facilities associated with utility operations, not recoverable through insurance or some other means, will be recoverable from our customers in accordance with the terms of our rate recovery agreements for each regulated subsidiary.

Air. The Federal Clean Air Act ("CAA") provides for the regulation of a variety of air emissions from new and existing electric generating plants. Final permits in accordance with the requirements of Title V of the 1990 amendments to the CAA have been issued for all of our electric generating facilities, with the exception of two 79 MW simple cycle gas turbine units which were constructed in 2002. These units currently are permitted under New York State Facility permits and Title V permits have been timely applied for and are pending issuance by the NYSDEC. Renewal applications have been submitted in a timely manner for 13 existing facilities whose initial permits will expire in 2004. The permits and timely renewal applications allow our electric generating plants to continue to operate without any additional significant expenditures, except as described below.

Our generating facilities are located within a CAA severe ozone non-attainment area, and are subject to Phase I, II, and III NO_X reduction requirements established under the Ozone Transport Commission ("OTC") memorandum of understanding. Our investments in boiler combustion modifications and the use of natural gas firing systems at our steam electric generating stations have enabled us to achieve the emission reductions required under Phase I, II, and III of the OTC memorandum in a cost-effective manner. We have achieved and expect to continue to achieve such emission reductions in a cost-effective manner through the use of low NO_X combustion control systems, the use of natural gas fuel and/or the purchases of allowances when necessary. Capital expenditures were incurred between $10 million and $15 million for combustion control systems and natural gas fuel capability additions over the last several years enhance compliance options.

In 2003, New York State promulgated regulations which will establish separate NO_X and SO_2 emission reduction requirements on electric generating facilities in New York State beginning in late 2004. KeySpan's facilities are expected to comply with the NO_X requirements without material additional expenditures because of previously installed emissions control equipment. SO2 compliance is expected to require a reduction in the sulfur content of the fuel oil used in our Northport and Port Jefferson facilities. Based on current projections, higher incremental fuel costs at these facilities will be approximately $10 million per year, and, contractually, are the obligation of LIPA in accordance with the terms of the PPA.

In December 2003, the United States Environmental Protection Agency ("USEPA") issued draft regulations that would require reductions of mercury and nickel as well as further reductions of NO_X and SO_2 from electric generating facilities on a national basis. The proposed mercury regulations would have no impact on KeySpan facilities since their application is limited to coal-fired plants. The proposed nickel, NO_X and SO_2 reduction requirements, if finalized as drafted, could require additional expenditures for emission control systems or greater use of natural gas in order to facilitate compliance. Until these regulations are finalized, the nature and extent of the financial impact on KeySpan, if any, cannot be determined.

In 2003, the Governor of New York initiated a Regional Greenhouse Gas Initiative that seeks to establish a coordinated multistate plan to reduce greenhouse gas emissions (primarily carbon dioxide) from electric generating emission sources in the Northeast. Several congressional initiatives are also under consideration that may also require greenhouse gas reductions from electric generating facilities nationwide. At the present time, it is not possible to predict the nature of the requirements, which ultimately will be imposed on KeySpan nor what, if any, financial impact such requirements would have on KeySpan facilities. However, our investments in emissions control technology and conversions to natural gas capability have resulted in a 15% reduction in carbon dioxide emissions over the last decade, while the electric generation industry as a whole increased carbon dioxide emissions by 26%. The addition of the efficient, combined cycle unit at Ravenswood will further reduce emission rates when it commences commercial operations in 2004.

Water. The Federal Clean Water Act provides for effluent limitations, to be implemented by a permit system, to regulate the discharge of pollutants into United States waters. We possess permits for our generating units which authorize discharges from cooling water circulating systems and chemical treatment systems. These permits are renewed from time to time, as required by regulation. Additional capital expenditures associated with the renewal of the surface water discharge permits for our power plants may be required by the DEC. We are currently monitoring impacts of our discharges on aquatic resources, in consultation with the DEC. Until our monitoring obligations are completed and proposed changes to the Environmental Protection Agency regulations under Section 316 of the Clean Water Act are finalized, the nature and cost of equipment upgrades cannot be determined.

Land. The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 and certain similar state laws (collectively "Superfund") impose liability, regardless of fault, upon generators of hazardous substances even before Superfund was enacted for costs associated with remediating contaminated property. In the course of our business operations, we generate materials which, after disposal, may become subject to Superfund. From time to time, we have received notices under Superfund concerning possible claims with respect to sites where hazardous substances generated by KeySpan or its predecessors and other potentially responsible parties were allegedly disposed. Normally the costs associated with such claims are allocated among the potentially responsible parties on a pro rata basis. The cost of these claims is not presently determinable. Superfund does, however, provide for joint and several liability against a single potentially responsible party. In the unlikely event that Superfund claims were pursued against us on that basis, the costs, may be material to our financial condition, results of operations or cash flows.

KeySpan has identified certain manufactured gas plant ("MGP") sites which were historically owned or operated by its subsidiaries (or such companies' predecessors). Operations at these sites between the mid 1800s to mid 1900s may have resulted in the release of hazardous substances. For a discussion on our MGP sites and further information concerning environmental matters, see Note 7 to the Consolidated Financial Statements, "Contractual Obligations and Contingencies - Environmental Matters."

Competition, Regulation and Rate Matters

Competition. Over the last several years, the natural gas and electric industries have undergone significant change as market forces moved towards replacing or supplementing rate regulation through the introduction of competition. A significant number of natural gas and electric utilities reacted to the changing structure of the energy industry by entering into business combinations, with the goal of reducing common costs, gaining size to better withstand competitive pressures and business cycles, and attaining synergies from the combination of operations. We engaged in two such combinations, the KeySpan/LILCO transaction in 1998 and our November 2000 acquisition of Eastern and EnergyNorth. For further information regarding the gas and electric industry, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation – "Regulatory Issues and Competitive Environment."

Ravenswood, the merchant plant in our Electric Services segment, is subject to competitive and other risks that could adversely impact the market price for the plant's output. Such risks include, but are not limited to, the construction of new generation or transmission capacity serving the New York City market. However, we cannot predict when or if new generation or transmission capacity will be built.

Additionally, our non-utility subsidiaries engaged in the Energy Services business compete with other mechanical, HVAC, and engineering companies, and in New Jersey are faced with competition from the regulated utilities that are still able to offer appliance repair and protection services.

Regulation. Public utility holding companies, like KeySpan, are regulated by the SEC under PUHCA and to some extent by state utility commissions through the regulation of corporate, financial and affiliate activities of public utilities. Our utility subsidiaries are subject to extensive federal and state regulation by state utility commissions, FERC and the SEC. Our gas and electric public utility companies are subject to either or both state and federal regulation. In general, state public utility commissions, such as the New York Public Service Commission ("NYPSC"), the Massachusetts Department of Telecommunications and Energy ("DTE") and the New Hampshire Public Utilities Commission ("NHPUC") regulate the provision of retail services, including the distribution and sale of natural gas and electricity to consumers. Each of the federal and state regulators also regulates certain transactions among our affiliates. FERC regulates interstate natural gas transportation and electric transmission, and has jurisdiction over certain wholesale natural gas sales and wholesale electric sales.

In addition, our non-utility subsidiaries are subject to a wide variety of federal, state and local laws, rules and regulations with respect to their business activities, including but not limited to those affecting public sector projects, environmental and labor laws and regulations, state licensing requirements, as well as state laws and regulations concerning the competitive retail commodity supply.

State Utility Commissions. Our regulated utility subsidiaries are subject to regulation by the NYPSC, DTE and NHPUC. The NYPSC regulates KEDNY and KEDLI. Although KeySpan Corporation is not regulated by the NYPSC, it is impacted by conditions that were included in the NYPSC order authorizing the 1998 KeySpan/LILCO transaction. Those conditions address, among other things, the manner in which KeySpan, its service company subsidiaries and its unregulated subsidiaries may interact with KEDNY and KEDLI. The NYPSC also regulates the safety, reliability and certain financial transactions of our Long Island generating facilities and our Ravenswood generating facility under a lightened regulatory standard. Our KEDNE subsidiaries are subject to regulation by the DTE and NHPUC. Our Energy Services subsidiaries which engage in the retail sale of electricity are also subject to regulation by the NYPSC. For further information regarding the state regulatory commissions, see the discussion in Item 7.

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Federal Energy Regulatory Commission. FERC regulates the sale of electricity at wholesale and the transmission of electricity in interstate commerce as well as certain corporate and financial activities of companies that are engaged in such activities. The Long Island generating facilities and the Ravenswood facility are subject to FERC regulation based on their wholesale energy transactions. In 1998, LIPA, KeySpan and the Staff of FERC stipulated to a five-year rate plan for the Long Island generating facilities with agreed-upon yearly adjustments, which have been approved by FERC. A rate filing reflecting a recalculated revenue requirement was submitted to FERC on October 31, 2003. On December 30, 2003, FERC issued an order accepting, in part, the rates subject to refund pending settlement discussions and hearings. We are unable to predict the outcome of those proceedings at this time. Our Ravenswood facility's rates are based on a market-based rate application approved by FERC. The rates that our Ravenswood facility may charge are subject to mitigation measures due to market power concerns of FERC. The mitigation measures are administered by the NYISO. FERC retains the ability in future proceedings, either on its own motion or upon a complaint filed with FERC, to modify the Ravenswood facility's rates, as well as the mitigation measures, if FERC concludes that it is in the public interest to do so.

KeySpan currently offers and sells the energy, capacity and ancillary services from the Ravenswood facility through the energy market operated by the NYISO. For information concerning the NYISO, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation – "Regulatory Issues and Competitive Environment."

FERC also has jurisdiction to regulate certain natural gas sales for resale in interstate commerce, the transportation of natural gas in interstate commerce and, unless an exemption applies, companies engaged in such activities. The natural gas distribution activities of KEDNY, KEDLI, KEDNE and certain related intrastate gas transportation functions are not subject to FERC jurisdiction. However, to the extent that KEDNY, KEDLI or KEDNE purchase or sell gas for resale in interstate commerce, such transactions are subject to FERC jurisdiction and have been authorized by FERC. Our interests in Iroquois, Honeoye, Steuben and KeySpan LNG are also fully regulated by FERC as natural gas companies.

Securities and Exchange Commission. As a result of the acquisition of Eastern and EnergyNorth, we became a registered holding company under PUHCA. Therefore, our corporate and financial activities and those of our subsidiaries, including their ability to pay dividends to us, are subject to regulation by the SEC. Under our holding company structure, we have no independent operations or source of income of our own and conduct substantially all of our operations through our subsidiaries and, as a result, we depend on the earnings and cash flow of, and dividends or distributions from, our subsidiaries to provide the funds necessary to meet our debt and contractual obligations and to pay dividends to our shareholders. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operations of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation by state regulatory authorities. For additional information concerning regulation by the SEC under PUHCA, see the discussion under the heading "Securities and Exchange Commission Regulation" contained in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" contained herein.

In addition, in November 2000, KeySpan received authorization from the SEC to operate three mutual service companies. Under this order, the SEC determined that, in accordance with PUHCA, KeySpan Corporate Services LLC ("KCS"), KeySpan Utility Services LLC ("KUS") and KeySpan Engineering & Survey, Inc. ("KENG") may operate to provide various services to KeySpan subsidiaries, including regulated utility companies, at cost fairly and equitably allocated among them.

Foreign Regulation. KeySpan's foreign operations in Northern Ireland, conducted through Premier, are subject to licensing by the Northern Ireland Department of Economic Development and regulation by the U.K. Department of Trade and Industry (with respect to the subsea and on-land portions of the Premier pipeline) and the Northern Ireland Director General, Office for the Regulation of Electricity and Gas (with respect to the Northern Ireland portion of the Premier pipeline). The licenses establish mechanisms for the establishment of rates for the conveyance and transportation of natural gas, and generally may not be revoked except upon long- term notice. KeySpan's assets in Canada are subject to regulation by Canadian federal and provincial authorities. Such regulatory authorities license various aspects of the facilities and pipeline systems as well as regulate safety, operational and environmental matters and certain changes in such facilities' and pipelines' capacities and operations.

Risks Related To Our Business

We are a Holding Company, and We and Our Subsidiaries are Subject to Federal and/or State Regulation Which Limits Our Financial Activities, Including the Ability of Our Subsidiaries to Pay Dividends and Make Distributions to Us

We are a holding company registered under PUHCA with no business operations or sources of income of our own. We conduct all of our operations through our subsidiaries and depend on the earnings and cash flow of, and dividends or distributions from, our subsidiaries to provide the funds necessary to meet our debt and contractual obligations and to pay dividends on our common stock. Because we are a registered holding company, our corporate and financial activities and those of our subsidiaries, including their ability to pay dividends to us from unearned surplus, are subject to PUHCA and regulation by the SEC.

In addition, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation by the utility regulatory commissions of New York, Massachusetts and New Hampshire. Pursuant to NYPSC orders, the ability of KEDNY and KEDLI to pay dividends to us is conditioned upon their maintenance of a utility capital structure with debt not exceeding 55% and 58%, respectively, of total utility capitalization. In addition, the level of dividends paid by both utilities may not be increased from current levels if a 40 basis point penalty is incurred under a customer service performance program. At the end of KEDNY's and KEDLI's rate years (September 30, 2003 and November 30, 2003, respectively), their ratios of debt to total utility capitalization were well in compliance with the ratios set forth above.

PUHCA Also Limits Our Business Operations and Our Ability to Affiliate with Other Utilities

In addition to limiting our financial activities, PUHCA also limits our operations to a single integrated utility system, plus additional energy related businesses, regulates transactions between us and our subsidiaries and requires SEC approval for specified utility mergers and acquisitions. In April 2003, the SEC determined that the companies that comprise our Energy Services business are "energy-related companies" and therefore retainable under existing SEC precedent. However, the SEC also required that certain of those companies increase the percentage of their work that is energy related.

Our Gas Distribution and Electric Services Businesses May Be Adversely Affected by Changes in Federal and State Regulation

The regulatory environment applicable to our gas distribution and our electric services businesses has undergone substantial changes in recent years, on both the federal and state levels. These changes have significantly affected the nature of the gas and electric utility and power industries and the manner in which their participants conduct their businesses. Moreover, existing statutes and regulations may be revised or reinterpreted, new laws and regulations may be adopted or become applicable to us or our facilities and future changes in laws and regulations may affect our gas distribution and our electric services businesses in ways that we cannot predict.

In addition, our operations are subject to extensive government regulation and require numerous permits, approvals and certificates from various federal, state and local governmental agencies. A significant portion of our revenues in our Gas Distribution and Electric Services segments are directly dependent on rates established by federal or state regulatory authorities, and any change in these rates and regulatory structure could significantly impact our financial results. Increases in utility costs other than gas, not otherwise offset by increases in revenues or reductions in other expenses, could have an adverse effect on earnings due to the time lag associated with obtaining regulatory approval to recover such increased costs and expenses in rates, and the uncertainty of whether regulatory commissions will allow full recovery of and return on such increased costs and expenses.

Various rulemaking proposals and market design revisions related to the wholesale power market are being reviewed at the federal level. These proposals, as well as legislative and other attention to the electric power industry could have a material adverse effect on our strategies and results of operations for our electric services business and our financial condition. In particular, we sell power and energy from our Ravenswood generating facility into the New York Independent System Operator, or NYISO, energy market at market based rates, subject to mitigation measures approved by the Federal Energy Regulatory Commission, or FERC. The pricing for both energy sales and services to the NYISO energy market is still evolving and some of FERC's price mitigation measures are subject to rehearing and possible judicial review.

Our Risk Mitigation Techniques Such as Hedging and Purchase of Insurance May Not Adequately Provide Protection

To mitigate our financial exposure related to commodity price fluctuations, KeySpan routinely enters into contracts to hedge a portion of our purchase and sale commitments, weather fluctuations, electricity sales, natural gas supply and other commodities. However, we do not always cover the entire exposure of our assets or our positions to market price volatility and the coverage will vary over time. To the extent we have unhedged positions or our hedging procedures do not work as planned, fluctuating commodity prices could cause our sales and net income to be volatile.

In addition, our business is subject to many hazards from which our insurance may not adequately provide coverage. An unexpected outage of Ravenswood, especially in the significant summer period, could materially impact our financial results. Damage to pipelines, equipment, properties and people caused by natural disasters, accidents, terrorism or other damage by third parties could exceed our insurance coverage. Although we do have insurance to protect against many of these contingent liabilities, this insurance is capped at certain levels, has self-insured retentions and does not provide coverage for all liabilities.

SEC Rules for Exploration and Production Companies May Require Us to Recognize a Non-Cash Impairment Charge at the End of Our Reporting Periods

We use the full cost method of accounting for our investments in natural gas and oil properties. These investments consist of our approximately 55% equity interest in The Houston Exploration Company and our ownership of KeySpan Exploration. Under the full cost method, all costs of acquisition, exploration and development of natural gas and oil reserves are capitalized into a full cost pool as incurred, and properties in the pool are depleted and charged to operations using the unit-of-production method based on production and proved reserve quantities. To the extent that these capitalized costs, net of accumulated depletion, less deferred taxes exceed the present value (using a 10% discount rate) of estimated future net cash flows from proved natural gas and oil reserves and the lower of cost or fair value of unproved properties, those excess costs are charged to operations. If a write-down is required, it would result in a charge to earnings but would not have an impact on cash flows. Once incurred, an impairment of gas properties is not reversible at a later date, even if gas prices increase.

Our Operating Results May Fluctuate on a Seasonal and Quarterly Basis

Our gas distribution business is a seasonal business and is subject to weather conditions. We receive most of our gas distribution revenues in the first and fourth quarters, when demand for natural gas increases due to colder weather conditions. As a result, we are subject to seasonal variations in working capital because we purchase natural gas supplies for storage in the second and third quarters and must finance these purchases. Accordingly, our results of operations in the future will fluctuate substantially on a seasonal basis. In addition, our New England-based gas distribution subsidiaries do not benefit from weather normalization tariffs, and results from our Ravenswood generating facility are directly correlated to the weather as the demand and price for the electricity it generates increases during extreme temperature conditions. As a result, fluctuations in weather between years may have a significant effect on our results of operations for these subsidiaries. The construction activities of our Energy Services subsidiaries are also affected by weather.

We Cannot Predict Whether LIPA will Exercise its Option to Purchase Our Long Island Generating Assets and the Effect of that Purchase on Us

Under the GPRA, LIPA has the right to purchase, at fair market value, during the six-month period beginning November 29, 2004, all of our Long Island based generating assets that had been previously owned by the Long Island Lighting Company (all Long Island units except for the 80MW facility at Port Jefferson and the 80MW facility in Glenwood). At this point in time, we cannot predict whether LIPA will exercise its right to purchase the assets, nor can we estimate the effect on our financial condition or results of operations if LIPA were to exercise its option.

A Substantial Portion of Our Revenues are Derived from Our Agreements with LIPA, and No Assurance Can Be Made that These Arrangements Will Be Renewed at the End of their Terms or that the Resolution of Certain Disputes Will Not Materially Impact the Financial Condition of the Company

We derive a substantial portion of our revenues in our electric services segment from a number of agreements with LIPA pursuant to which we manage LIPA's transmission and distribution system and supply the majority of LIPA's customers' electricity needs. The agreements terminate at various dates between May 28, 2006 and May 28, 2013, and at this time, we can provide no assurance that any of the agreements will be renewed or extended, or if they were to be renewed or extended, the terms and conditions thereof. In addition, given the complexity of these arrangements, disputes arise from time to time between the Company and LIPA concerning the rights and obligations of each party to make and receive payments as required pursuant to the terms of these agreements. As a result, the Company is unable to determine what effect, if any, the ultimate resolution of these disputes will have on its financial condition or results of operations.

We Own Approximately 55% of Houston Exploration and Our Results of Operation are Therefore Subject to the Risks Affecting its Business

We own approximately 55% of Houston Exploration. Therefore, our results of operations in our energy investments segment are subject to the same risks and uncertainties that affect the operations of Houston Exploration. In addition to the risks set forth under the caption ' -- SEC rules for exploration and production companies may require us to recognize a non-cash impairment charge at the end of our reporting periods,' these risks and uncertainties include:

> The volatility of natural gas and oil prices. If natural gas and oil prices decline, the amount of natural gas and oil Houston Exploration can economically produce may be reduced, which may result in a material decline in its revenue.

The potential inability of Houston Exploration to meet its capital requirements. If Houston Exploration is unable to meet its capital requirements to fund, develop, acquire and produce natural gas and oil reserves, its oil and gas reserves will decline.

Substantial indebtedness. Houston Exploration's outstanding indebtedness under its bank credit facility and the indenture governing its senior subordinated notes contain covenants that require a substantial portion of its cash flow from operations to be dedicated to its debt service obligations and impose other restrictions that limit its ability to borrow additional funds or dispose of assets. These restrictions may affect its flexibility in planning for, and reacting to, changes in business conditions.

Estimates of proved reserves and future net revenue may change. Any significant variance from the assumptions used to estimate proved reserves or natural gas could result in the actual quantity of Houston Exploration's reserves and future net cash flow being materially different from the estimates in its reserve report.

A Decline or an Otherwise Negative Change in the Ratings or Outlook on Our Securities Could Have a Materially Adverse Impact on Our Ability to Secure Additional Financing on Favorable Terms

The credit rating agencies that rate our debt securities regularly review our financial condition and results of operations. We can provide no assurances that the ratings or outlook on our debt securities will not be reduced or otherwise negatively changed. A negative change in the ratings or outlook on our debt securities could have a materially adverse impact on our ability to secure additional financing on favorable terms.

Our Costs of Compliance with Environmental Laws are Significant, and the Cost of Compliance with Future Environmental Laws Could Adversely Affect Us

Our operations are subject to extensive federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and the health and safety of our employees. These environmental laws and regulations expose us to costs and liabilities relating to our operations and our current and formerly owned properties. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment and permits at our facilities. Costs of compliance with environmental regulations, and in particular emission regulations, could have a material impact on our electric services business and our results of operations and financial position, especially if emission limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated or the number and type of electric generating plants we operate increase.

In addition, we are responsible for the clean-up of contamination at certain manufactured gas plant ("MGP") sites and at other sites and are aware of additional MGP sites where we may have responsibility for clean-up costs. While our gas utility subsidiaries' rate plans generally allow for the full recovery of the costs of investigation and remediation of most of our MGP sites, these rate recovery mechanisms may change in the future. To the extent rate recovery mechanisms change in the future, or if additional environmental matters arise in the future at our currently or historically owned facilities, at sites we may acquire in the future or at third-party waste disposal sites, costs associated with investigating and remediating these sites could have a material adverse effect on our results of operations and financial condition.

Our Businesses are Subject to Competition and General Economic Conditions Impacting Demand for Services

Ravenswood, our merchant generation plant, in our Electric Services segment, is subject to competition that could adversely impact the market price for the electricity it produces. Construction of new transmission facilities could also cause significant changes to the market. If generation and/or transmission facilities are constructed, and/or the availability of our Ravenswood facility deteriorates, then the capacity and energy sales quantities could be adversely affected. We cannot predict, however, when or if new power plants or transmission facilities will be built or the nature of the future New York City energy requirements.

Competition facing our unregulated Energy Services businesses, including but not limited to competition from other mechanical, plumbing, heating, ventilation and air conditioning, and engineering companies, as well as, other utilities and utility holding companies that are permitted to engage in such activities, could adversely impact our financial results and the value of those businesses, resulting in decreased earnings as well as write-downs of the carrying value of those businesses.

Our Gas Distribution segment faces competition with distributors of alternative fuels and forms of energy, including fuel oil and propane. Our ability to continue to add new gas distribution customers may significantly impact financial results. The gas distribution industry has experienced a decrease in consumption per customer over time, partially due to increased efficiency of customers' appliances. Our Gas Distribution segment is dependent upon the ability to add new customers to our system in a cost-effective manner. While our Long Island and New England utilities have significant growth potential, we cannot be sure new customers will continue to offset the decrease in consumption of our existing customer base. There are a number of factors outside of our control that impact whether a potential customer converts from an alternative fuel to gas, including general economic factors impacting customers willingness to invest in new gas equipment.

Employee Matters

As of December 31, 2003, KeySpan and its wholly-owned subsidiaries had approximately 11,300 employees. Of that total, approximately 5,800 employees in our regulated companies are covered under collective bargaining agreements. KeySpan has not experienced any work stoppage during the past five years and considers its relationship with employees, including those covered by collective bargaining agreements, to be good.

Prior to their expiration in February, KeySpan reached tentative agreements with IBEW Locals 1049 and 1381 on new collective bargaining agreements. These Unions represent KeySpan employees in physical and clerical positions respectively, and serve our Long Island customers. The new four-year agreements are expected to be ratified by each respective union before the end of March 2004.

Executive Officers of the Company. Certain information regarding executive officers of KeySpan and certain of its subsidiaries is set forth below:

Robert B. Catell

Mr. Catell, age 67, has been a Director of KeySpan since its creation in May 1998. He was elected Chairman of the Board and Chief Executive Officer in July 1998. He served as its President and Chief Operating Officer from May 1998 through July 1998. Mr. Catell joined KEDNY in 1958 and became an officer in 1974. He was elected Vice President in 1977, Senior Vice President in 1981 and Executive Vice President in 1984. He was elected Chief Operating Officer in 1986 and President in 1990. Mr. Catell continued to serve as President and Chief Executive Officer of KEDNY from 1991 through 1996, when he was elected Chairman and Chief Executive Officer. In 1997, Mr. Catell was elected Chairman, President and Chief Executive Officer of KEDNY and its parent KeySpan Energy Corporation. Mr. Catell also serves on the Board of Directors for Houston Exploration.

Robert J. Fani

Mr. Fani, age 50, was elected President and Chief Operating Officer of KeySpan in October 2003. Mr. Fani joined KEDNY in 1976, and held a variety of management positions in distribution, engineering, planning, marketing and business development. He was elected Vice President in 1992. In 1997, Mr. Fani was promoted to Senior Vice President of Marketing and Sales for KEDNY. In 1998, he assumed the position of Senior Vice President of Marketing and Sales for KeySpan. In September 1999, he became Senior Vice President for Gas Operations and was promoted to Executive Vice President for Strategic Services in February 2000 and then to President of the KeySpan Energy Services and Supply Group in 2001. In January 2003, he was named President of KeySpan's Energy Assets and Supply Group until assuming his current position in October 2003. Mr. Fani also serves on the Board of Directors for Houston Exploration.

Wallace P. Parker Jr.

Mr. Parker, age 54, was elected President of the KeySpan Energy Delivery and Customer Relations Group in January 2003. He also serves as Vice Chairman and Chief Executive Officer of KeySpan Services, Inc. since October 2003. He had previously served as President, KeySpan Energy Delivery, since June 2001, and from February 2000 served as Executive Vice President of Gas Operations. He joined KEDNY in 1971 and served in a wide variety of management positions. In 1987, he was named Assistant Vice President for marketing and advertising and was elected Vice President in 1990. In 1994, Mr. Parker was promoted to Senior Vice President of Human Resources and in August 1998 was promoted to Senior Vice President of Human Resources of KeySpan.

Steven L. Zelkowitz

Mr. Zelkowitz, age 54, was elected President of KeySpan's Energy Assets and Supply Group in October 2003. Prior to that, he served as Executive Vice President & Chief Administrative Officer since January 2003. He joined KeySpan as Senior Vice President and Deputy General Counsel in October 1998, and was elected Senior Vice President and General Counsel in February 2000. In July 2001, Mr. Zelkowitz was promoted to Executive Vice President and General Counsel, and in November 2002, he was named Executive Vice President, Administration & Compliance, with responsibility for the offices of General Counsel, Human Resources, Regulatory Affairs, Enterprise Risk Management and administratively for Internal Auditing. Before joining the Company, Mr. Zelkowitz practiced law with Cullen and Dykman LLP in Brooklyn, New York, specializing in energy and utility law and had been a partner since 1984. He served on the firm's Executive Committee and was head of its Corporate/Energy Department.

John A. Caroselli

Mr. Caroselli, age 49, was elected Executive Vice President and Chief Strategy Officer in January 2003. Mr. Caroselli is responsible for Brand Management, Strategic Marketing, Strategic Planning, Strategic Performance, Human Resources, and Information Technology. Mr. Caroselli came to KeySpan in 2001 and at that time served as Executive Vice President of Strategic Development. Before joining KeySpan, Mr. Caroselli held the position of Executive Vice President of Corporate Development at AXA Financial. Prior to that, he held senior officer positions with Chase Manhattan, Chemical Bank and Manufacturers Hanover Trust. He has extensive experience in brand management, marketing, communications, human resources, facilities management, e-business and change management.

Gerald Luterman

Mr. Luterman, age 60, was elected Executive Vice President and Chief Financial Officer in February 2002. He previously served as Senior Vice President and Chief Financial Officer since joining KeySpan in July 1999. He formerly served as Chief Financial Officer of barnesandnoble.com and Senior Vice President and Chief Financial Officer of Arrow Electronics, Inc. Prior to that, from 1985 through 1996, he held executive positions with American Express. Mr. Luterman also serves on the Board of Directors for Houston Exploration.

Anthony Nozzolillo

Mr. Nozzolillo, age 55, was elected Executive Vice President of Electric Operations in February 2000. He previously served as Senior Vice President of KeySpan's Electric Business Unit from December 1998 to January 2000. He joined LILCO in 1972 and held various positions, including Manager of Financial Planning and Manager of Systems Planning. Mr. Nozzolillo served as LILCO's Treasurer from 1992 to 1994 and as Senior Vice President of Finance and Chief Financial Officer from 1994 to 1998.

Lenore F. Puleo

Ms. Puleo, age 50, was elected Executive Vice President of Shared Services in March 2004. She previously served as Executive Vice President of Client Services in February 2000. Prior to that, she served as Senior Vice President of Customer Relations for KEDNY from May 1994 to May 1998, and for KeySpan from May 1998 to January 2000. She joined KEDNY in 1974 and worked in management positions in KEDNY's Accounting, Treasury, Corporate Planning and Human Resources areas. She was given responsibility for the Human Resources Department in 1987 and was named a Vice President in 1990. Ms. Puleo was promoted to Senior Vice President of KEDNY's Customer Relations in 1994.

Nickolas Stavropoulos

Mr. Stavropoulos, age 45, was elected Executive Vice President, KeySpan Corporation, and President, KeySpan Energy Delivery New England, in April 2002. Prior to that, he was Senior Vice President of sales and marketing in New England since 2000. Prior to joining KeySpan, Mr. Stavropoulos was Senior Vice President of marketing and gas resources for Boston Gas Company. Before joining Boston Gas, he was Executive Vice President and Chief Financial Officer for Colonial Gas Company. In 1995, Mr. Stavropoulos was elected Executive Vice President – Finance, Marketing and CFO, and assumed responsibility for all of Colonial's financial, marketing, information technology and customer service functions. Mr. Stavropoulos was also a director of Colonial Gas Company.

John J. Bishar, Jr.

Mr. Bishar, age 54, became Senior Vice President, General Counsel and Secretary on May 8, 2003, with responsibility for the Legal Services Business Unit and the Corporate Secretary's Office. Prior to that, he joined KeySpan as Senior Vice President and General Counsel on November 1, 2002. Before joining KeySpan, Mr. Bishar practiced law with Cullen and Dykman LLP. He was the Managing Partner from 1993 through 2002 and was a member of the firm's Executive Committee. From 1980 to 1987, Mr. Bishar was Vice President, General Counsel and Corporate Secretary of LITCO Bancorporation of New York, Inc. In 1987, Mr. Bishar returned to Cullen and Dykman LLP as a partner responsible for the firm's commercial lending and commercial real estate lending activities for a variety of financial institutions.

Joseph F. Bodanza

Mr. Bodanza, age 56, was elected Senior Vice President, Regulatory Affairs and Chief Accounting Officer on April 1, 2003. Prior to his appointment, he served as Senior Vice President of Finance Operations and Regulatory Affairs since August 2001 and was Senior Vice President and Chief Financial Officer of KEDNE. Mr. Bodanza previously served as Senior Vice President of Finance and Management Information Systems and Treasurer of Eastern Enterprise's Gas Distribution Operations. Mr. Bodanza joined Boston Gas Company in 1972, and held a variety of positions in the financial and regulatory areas before becoming Treasurer in 1984. He was elected Vice President and Treasurer in 1988.

John F. Haran

Mr. Haran, age 53, was elected Senior Vice President of KeySpan Energy Delivery and Chief Gas Engineer in March 2004. He had been Senior Vice President of gas operations for KEDNY and KEDLI in April 2002. Mr. Haran joined The Brooklyn Union Gas Company in 1972, and has held management positions in operations, engineering and marketing and sales. He was named Vice President of KEDNY gas operations in 1996 and in 2000 moved to the position of Vice President of KEDLI gas operations.

David J. Manning

Mr. Manning, age 53, was elected Senior Vice President for Corporate Affairs in April 1999. Before joining KeySpan, Mr. Manning had been President of the Canadian Association of Petroleum Producers since 1995. From 1993 to 1995, he was Deputy Minister of Energy for the Province of Alberta, Canada. From 1988 to 1993, he was Senior International Trade Counsel for the Government of Alberta, based in New York City. Previously, he was in the private practice of law in Canada.

H. Neil Nichols

Mr. Nichols, age 66, was elected Senior Vice President of KeySpan's Corporate Development and Asset Management division in March 1999. He also serves as President of KeySpan Energy Development Corporation ("KEDC"), a position to which he was elected in March 1998. KEDC is a wholly-owned subsidiary of KeySpan responsible for our Energy Investments segment. Since February 1999, Mr. Nichols also has responsibility for KeySpan Energy Trading Services, LLC, which provides fuel-procurement management and energy-trading services as agent for LIPA. Mr. Nichols joined KeySpan in 1997 as a broad-based negotiator and business strategist with comprehensive finance and treasury experience in domestic and international markets. He is also a member of the Board or Directors for Houston Exploration Company and KeySpan Facilities Income Fund. Prior to joining KeySpan, Mr. Nichols was an owner and president of Corrosion Interventions, Ltd. in Toronto, Canada. He also served as Chief Financial Officer and Executive Vice President with TransCanada PipeLines.

Michael J. Taunton

Mr. Taunton, age 48, was named Senior Vice President and Treasurer in March, 2004. He had been KeySpan's Vice President and Treasurer since June 2000. Prior to that time, he served as Vice President of Investor Relations since September 1998. He joined KEDNY in 1975 and held a succession of positions in Accounting, Customer Service, Corporate Planning, Budgeting and Forecasting, Marketing and Sales, and Business Process Improvement. During the KeySpan/LILCO merger, Mr. Taunton co-managed the day-to-day transition process of the merger and then served on the Transition Team during the acquisition of Eastern Enterprises.

Colin P. Watson

Mr. Watson, age 52, was named Senior Vice President of KeySpan's Strategic Marketing and E-Business division effective March 1, 2000. He previously served as Vice President of Strategic Marketing from May 1998 until his promotion to Senior Vice President. Mr. Watson joined KEDNY in 1997 as Vice President of Strategic Marketing. From 1973 to 1997, he held several positions at NYNEX, including Vice President of General Business Sales and Managing Director of worldwide operations. In support of New York City's bid to host the 2012 Olympic games, KeySpan has provided NYC2012 with the expertise and guidance of Mr. Watson on a full-time basis.

Elaine Weinstein

Ms. Weinstein, age 57, was named Senior Vice President and Chief Diversity Officer in March 2004. She had served as Senior Vice President of KeySpan's Human Resources division in November 2000. She previously served as Vice President of Staffing and Organizational Development from September 1998 to her election as Senior Vice President. Prior to that time, Ms. Weinstein was General Manager of Employee Development since joining KeySpan in 1995. Prior to 1995, Ms. Weinstein was Vice President of Training and Organizational Development at Merrill Lynch.

Lawrence S. Dryer

Mr. Dryer, 44, was elected Vice President and General Auditor in June 2003. He previously served in this position from September 1998 to August 2001. In August 2001, he was named Senior Vice President and Chief Financial Officer of KeySpan Services, Inc. Prior to such positions, Mr. Dryer had been with LILCO from 1992 to 1998 as Director of Internal Audit. Prior to joining LILCO, Mr. Dryer was an Audit Manager with Coopers & Lybrand.

Theresa Balog

Ms. Balog, age 42, was named Vice President and Controller of KeySpan in April 2003. She joined KeySpan in 2002 as Assistant Controller. Prior to joining KeySpan, Ms. Balog was Chief Accounting Officer for NiSource and held a variety of positions with the Columbia Energy Group.

Item 2. *Properties*

Information with respect to KeySpan's material properties used in the conduct of its business is set forth in, or incorporated by reference in, Item 1 hereof. Except where otherwise specified, all such properties are owned or, in the case of certain rights-of-way used in the conduct of its gas distribution business, held pursuant to municipal consents, easements or long-term leases, and in the case of gas and oil properties, held under long-term mineral leases. In addition to the information set forth therein with respect to properties utilized by each business segment, KeySpan leases the executive headquarters located in Brooklyn, New York. In addition, we lease other office and building space, office equipment, vehicles and power operated equipment.

Our properties are adequate and suitable to meet our current and expected business requirements. Moreover, their productive capacity and utilization meet our needs for the foreseeable future. KeySpan continually examines its real property and other property for its contribution and relevance to our businesses and when such properties are no longer productive or suitable, they are disposed of as promptly as possible. In the case of leased office space, we anticipate no significant difficulty in leasing alternative space at reasonable rates in the event of the expiration, cancellation or termination of a lease.

Item 3. ***Legal Proceedings***

See Note 7 to the Consolidated Financial Statements, "Contractual Obligations and Contingencies - Legal Matters."

Item 4. ***Submission of Matters to a Vote of Security Holders***

No matters were submitted to a vote of the security holders during the last quarter of the 12 months ended December 31, 2003.

PART II

Item 5. ***Market for Registrant's Common Equity and Related Stockholder Matters***

KeySpan's common stock is listed and traded on the New York Stock Exchange and the Pacific Stock Exchange under the symbol "KSE." As of March 1, 2004, there were approximately 75,070 registered record holders of KeySpan's common stock. The following table sets forth, for the quarters indicated, the high and low sales prices and dividends declared per share for the periods indicated:

2003	*High*	*Low*	*Dividends Per Share*
First Quarter	$38.14	$31.02	$0.445
Second Quarter	$37.51	$31.87	$0.445
Third Quarter	$35.83	$32.30	$0.445
Fourth Quarter	$37.09	$33.64	$0.445

2002	*High*	*Low*	*Dividends Per Share*
First Quarter	$36.72	$30.01	$0.445
Second Quarter	$37.45	$34.35	$0.445
Third Quarter	$38.19	$27.41	$0.445
Fourth Quarter	$37.15	$30.75	$0.445

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth securities authorized for issuance under equity compensation plans for the year ended December 31, 2003:

Stock Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of equity outstanding options, warrants and rights	Number of securities remaining available for future issuance under compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders			
Stock Options	10,320,743	$31.39	6,783,675
Restricted Stock	84,318	N/A	
Performance Shares	186,708	N/A	
Equity compensation plans not approved by security holders	N/A	N/A	N/A
Total	10,591,769	$31.39	6,783,675 (1)

(1) Includes grants of options, restricted stock, and performance shares pursuant to KeySpan's Long-Term Incentive Compensation Plan, as amended, and options granted pursuant to the Brooklyn Union Long-Term Incentive Compensation Plan and options granted pursuant to the Eastern Enterprises 1995 Stock Option Plan and the Eastern Enterprises 1996 Non-Employee Trustee's Stock Option Plan, as well as 328,000 shares of Common Stock issued pursuant to the Stock Plan.

Item 6. *Selected Financial Data*

(In Thousands of Dollars, Except Per Share Amounts)	Year Ended December 31, 2003	2002	2001	2000	1999
Income Summary					
Revenues					
Gas Distribution	$ 4,161,272	$ 3,163,761	$ 3,613,551	$ 2,555,785	$ 1,753,132
Electric Services	1,503,086	1,421,043	1,421,079	1,444,711	861,582
Energy Services	641,432	938,761	1,100,167	770,110	186,529
Energy Investments and other	609,371	447,101	498,318	310,096	153,370
Total revenues	6,915,161	5,970,666	6,633,115	5,080,702	2,954,613
Operating expenses					
Purchased gas for resale	2,495,102	1,653,273	2,171,113	1,408,680	744,432
Fuel and purchased power	414,633	395,860	538,532	460,841	17,252
Operations and maintenance	2,005,796	2,101,897	2,114,759	1,659,736	1,091,166
Depreciation, depletion and amortization	574,074	514,613	559,138	330,922	253,440
Early retirement and severance charges		-	-	65,175	-
Operating taxes	418,236	381,767	448,924	421,936	366,154
Total operating expenses	5,907,841	5,047,410	5,832,466	4,347,290	2,472,444
Gain on sale of property	15,123	4,730	-	-	-
Income from equity investments	19,214	14,096	13,129	20,010	15,347
Operating income	1,041,657	942,082	813,778	753,422	497,516
Other deductions	(340,165)	(301,253)	(359,393)	(233,410)	(102,543)
Income taxes	277,311	243,479	210,693	217,262	136,362
Earnings from continuing operations	424,181	397,350	243,692	302,750	258,611
Discontinued Operations					
Income (loss) from operations, net of tax	-	(3,356)	10,918	(1,943)	-
Loss on disposal, net of tax	-	(16,306)	(30,356)	-	-
Loss from discontinued operations	-	(19,662)	(19,438)	(1,943)	-
Cumulative change in accounting principles	(37,451)	-	-	-	-
Net income	386,730	377,688	224,254	300,807	258,611
Preferred stock dividend requirements	5,844	5,753	5,904	18,113	34,752
Earnings for common stock	$ 380,886	$ 371,935	$ 218,350	$ 282,694	$ 223,859
Financial Summary					
Earnings per share ($)	2.41	2.63	1.58	2.10	1.62
Cash dividends declared per share ($)	1.78	1.78	1.78	1.78	1.78
Book value per share, year-end ($)	22.94	20.67	20.73	20.65	20.26
Market value per share, year-end ($)	36.80	35.24	34.65	42.38	23.19
Shareholders, year-end	75,067	78,281	82,300	86,900	90,500
Capital expenditures ($)	1,011,716	1,061,022	1,059,759	925,257	725,670
Total assets ($)	14,626,784	12,980,050	11,789,606	11,307,465	6,730,691
Common shareholders' equity ($)	3,661,948	2,944,592	2,890,602	2,815,816	2,712,325
Redeemable preferred stock ($)	-	-	-	-	363,000
Preferred stock ($)	83,568	83,849	84,077	84,205	84,339
Long-term debt ($)	5,611,432	5,224,081	4,697,649	4,116,441	1,682,702
Total capitalization ($)	9,356,948	8,252,522	7,672,328	7,016,462	4,479,366

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

KeySpan Corporation (referred to herein as "KeySpan", "we", "us" and "our") is a registered holding company under the Public Utility Holding Company Act of 1935, as amended ("PUHCA"). KeySpan operates six regulated utilities that distribute natural gas to approximately 2.5 million customers in New York City, Long Island, Massachusetts and New Hampshire, making us the fifth largest gas distribution company in the United States and the largest in the Northeast. We also own and operate electric generating plants in Nassau and Suffolk Counties on Long Island and in Queens County in New York City and are the largest investor owned generator in New York State. Under contractual arrangements, we provide power, electric transmission and distribution services, billing and other customer services for approximately one million electric customers of the Long Island Power Authority ("LIPA"). KeySpan's other subsidiaries are involved in gas and oil exploration and production; underground gas storage; liquefied natural gas storage; wholesale and retail electric marketing; appliance service; plumbing, heating, ventilation, air conditioning and other mechanical services; large energy-system ownership, installation and management; fiber optic services; and engineering and consulting services. We also invest and participate in the development of natural gas pipelines, natural gas processing plants, electric generation, and other energy-related projects, domestically and internationally. (See Note 2 to the Consolidated Financial Statements "Business Segments" for additional information on each operating segment.)

Consolidated Summary of Results

Operating income by segment, as well as consolidated earnings available for common stock is set forth in the following table for the periods indicated.

	Year Ended December 31,		
(In Thousands of Dollars, Except Per Share Amounts)	2003	2002	2001
Gas Distribution	$ 574,254	$ 531,134	$ 481,393
Electric Services	268,977	288,796	269,721
Energy Services	(38,066)	(11,935)	(147,485)
Energy Investments	238,554	142,594	178,783
Eliminations and other	(2,062)	(8,507)	31,366
Operating Income	1,041,657	942,082	813,778
Interest charges	(307,694)	(301,504)	(353,470)
Other Income and (deductions)	(32,471)	251	(5,923)
Income taxes	(277,311)	(243,479)	(210,693)
Income from Continuing Operations	424,181	397,350	243,692
Cumulative change in accounting principles	(37,451)	-	-
Loss from discontinued operations	-	(19,662)	(19,438)
Net Income	386,730	377,688	224,254
Preferred stock dividend requirements	5,844	5,753	5,904
Earnings for Common Stock	$ 380,886	$ 371,935	$ 218,350
Basic Earnings per Share:			
Continuing operations, less preferred stock dividends	$ 2.64	$ 2.77	$ 1.72
Change in accounting principles	(0.23)	-	-
Discontinued operations	-	(0.14)	(0.14)
	$ 2.41	$ 2.63	$ 1.58

Operating income in 2003 increased $99.6 million, or 11% compared to 2002. This increase in operating income reflects higher earnings from the Energy Investments and Gas Distribution segments, somewhat offset by decreases in earnings from the Electric Services and Energy Services segments. The Energy Investment segment benefited from higher earnings associated with gas exploration and production activities as a result of significantly higher realized gas prices and higher production volumes. The Gas Distribution segment benefited from colder weather during the January through March 2003 heating season compared to the same period last year, as well as from load growth. Further, during 2003 we recorded $15.1 million in gains from property sales, primarily 550 acres of real property located on Long Island. The Energy Services group of companies were adversely impacted by the decline in construction industry activity in the Northeastern United States during most of the year. Lower results from the Electric Services segment were attributable to higher operating costs, as well as lower revenues from our merchant generating facility, due in part to cooler summer weather. (See the discussion under the caption "Review of Operating Segments" for further details on each segment.)

Interest charges increased 2% in 2003, compared to last year, primarily as a result of the termination of certain interest-rate derivative swap instruments that were in effect in 2002. (See Note 8 to the Consolidated Financial Statements "Hedging, Derivative Financial Instruments and Fair Values.")

Other income and (deductions) reflects a number of significant items that impacted comparative results. During 2003, we monetized a portion of our Canadian and Northern Ireland investments, as well as a portion of our ownership interest in The Houston Exploration Company ("Houston Exploration"), our gas exploration and production subsidiary. During the year, we sold 39.09% of our interest in KeySpan Canada through an income trust fund. KeySpan Canada has natural gas processing plants and gathering facilities in Western Canada. Additionally, we sold our 20% interest in Taylor NGL LP that owns and operates two extraction plants also located in Canada. We recorded a pre-tax loss of $30.3 million ($34.1 million after-tax, or $0.22 per share) associated with these sales. Further, in February 2004 we entered into an agreement to sell an additional 36% of our interest in KeySpan Canada. (See Note 15 to the Consolidated Financial Statements "Subsequent Events.") In the fourth quarter of 2003, we completed the sale of our 24.5% interest in Phoenix Natural Gas, located in Northern Ireland, and recorded a pre-tax gain of $24.7 million, $16.0 million after-tax, or $0.10 per share.

Additionally in 2003, we reduced our ownership interest in Houston Exploration from 66% to approximately 55% following the repurchase, by Houston Exploration, of three million shares of common stock owned by KeySpan. We recorded a gain of $19.0 million on this transaction. Income taxes were not provided on this transaction since the transaction was structured as a return of capital.

In total, KeySpan recorded a pre-tax gain of $13.4 million from the monetization of certain non-core assets. The after-tax gain from these three asset sales, however, was minimal due to the different tax treatment associated with each transaction.

Also in 2003, we called approximately $447 million of outstanding promissory notes that were issued to LIPA in connection with the KeySpan/Long Island Lighting Company ("LILCO") business combination completed in May 1998, and recorded debt redemption charges of $18.2

million in other income and (deductions). Further, Houston Exploration incurred costs of $5.9 million to retire $100 million of 8.625% Notes due 2008.

Other income and (deductions) also reflects severance tax refunds totaling $21.6 million recorded by Houston Exploration for severance taxes paid in 2002 and earlier periods, compared to $9.1 million recorded in 2002, as well as $6.5 million of realized foreign currency translation gains. Finally, other income and (deductions) reflects minority interest adjustments related to Houston Exploration and KeySpan Canada, as well as carrying charges on certain regulatory assets.

The increase in income tax expense in 2003 compared to 2002 generally reflects a higher level of pre-tax earnings. Further income tax expense for 2003 and 2002 includes a number of items impacting comparative results. During 2003, the partial monetization of our Canadian investments resulted in tax expense of $3.8 million, reflecting certain United States partnership tax rules. In addition, we recorded an adjustment to income tax expense of $6.1 million due to the state of Massachusetts disallowing the carry forward of net operating losses incurred by regulated utilities. This adjustment resulted in an increase to income tax expense of $6.1 million. Offsetting, to some extent, these increases to tax expense, was a tax benefit recorded in 2003 of $9.0 million associated with certain New York City general corporation tax issues. In addition, certain costs associated with employee deferred compensation plans were deducted for federal income tax purposes in 2003. These costs, however, are not expensed for "book" purposes resulting in a beneficial permanent book-to-tax difference of $6.3 million.

Income tax expense for 2002 reflects a tax benefit of $15 million as a result of the favorable resolution of certain outstanding tax issues related to the KeySpan/LILCO merger. Additionally, we recorded an adjustment to deferred income taxes of $177.7 million reflecting a decrease in the tax basis of the assets acquired at the time of the merger. This adjustment was a result of a revised valuation study. Concurrent with the deferred tax adjustment, we reduced current income taxes payable by $183.2 million, resulting in a $5.5 million income tax benefit. Also, it should be noted that pre-tax income in the Consolidated Statement of Income reflects minority interest adjustments, whereas income taxes reflect the full amount of subsidiary taxes.

In January 2002, KeySpan announced that it had entered into an agreement to sell Midland Enterprises LLC ("Midland"), its marine barge business. During the fourth quarter of 2001, in anticipation of this divestiture, which closed on July 2, 2002, an estimated loss on the sale of Midland was recorded as discontinued operations, as well as an estimate for Midland's results of operations for the first nine months of 2002. In the second quarter of 2002, we recorded an additional after-tax loss of $19.7 million, primarily reflecting a provision for certain city and state taxes that resulted from a change in our tax structuring strategy.

In January 2003, the Financial Accounting Standards Board ("FASB") issued Financial Interpretation Number 46 ("FIN 46"), "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51"; FIN 46 requires consolidation of variable interest entities. KeySpan has an arrangement with a variable interest entity through which we lease a portion of the 2,200-megawatt Ravenswood electric generating facility ("Ravenswood facility"). Based upon KeySpan's current status as the primary beneficiary, we were required to consolidate the variable interest entity as of December 31, 2003. As a result of implementing FIN 46, we recognized a non-cash, after-tax charge of $37.6 million, or $0.23 per share related to "catch-up" depreciation of the facility since its acquisition in June 1999 and recorded the charge as a cumulative change in accounting principle. (See Note 7 to the Consolidated Financial Statements "Contractual Obligations, Financial Guarantees and Contingencies" for an explanation of the leasing arrangement for the Ravenswood facility, as well as an explanation of the implementation of FIN 46.)

As a result of the above mentioned items, income from continuing operations, less preferred stock dividends, increased $26.7 million, or 7% in 2003 compared to 2002. Earnings per share from continuing operations, however, decreased by $0.13 per share, reflecting the issuance of 13.9 million shares of common stock on January 17, 2003, as well as the re-issuance of shares held in treasury pursuant to dividend reinvestment and employee benefit plans. The increase in average common shares outstanding reduced 2003 earnings per share by $0.32 compared to 2002. Comparative earnings available for common stock, which includes the cumulative change in accounting principle recorded in 2003, as well as the loss on discontinued operations recorded in 2002, increased $9.0 million in 2003 compared to 2002. Earnings per share, however, decreased by $0.22 per share reflecting the higher level of common stock outstanding in 2003.

KeySpan's earnings for 2003 were forecasted to be approximately $2.45 to $2.60 per share, including the effect of the equity issuance in January 2003 and excluding special items. Earnings from continuing core operations (defined for this purpose as all continuing operations other than exploration and production, less preferred stock dividends) were forecasted to be approximately $2.15 to $2.20 per share, while earnings from exploration and production operations were forecasted to be approximately $0.30 to $0.40 per share. Actual 2003 earnings from continuing core operations, as defined, were $2.16 per share, while earnings from exploration and production operations were $0.48 per share.

Operating income for the year ended December 31, 2002, increased $128.3 million compared to the same period in 2001. The increase in operating income primarily reflects the following two significant events that are discussed in more detail below: (i) the discontinuance of goodwill amortization in 2002; and (ii) the recording of special items in 2001 which resulted in the recognition of certain gains and losses. These benefits to comparative operating income were offset, in part, by a decrease in natural gas prices, particularly during the first quarter of 2002, which reduced earnings associated with gas exploration and production operations. Further, the impact of extremely warm weather during the first quarter of 2002 adversely impacted natural gas consumption by gas distribution customers and operating income in the Gas Distribution segment. (See "Review of Operating Segments" for a detailed discussion of operating income for each of KeySpan's lines of business.)

In January 2002, we adopted Statement of Financial Accounting Standard ("SFAS") 142 "Goodwill and Other Intangible Assets." The key requirements of this Statement include the discontinuance of goodwill amortization, a revised framework for testing goodwill impairment and new criteria for the identification of intangible assets. Consolidated goodwill amortization for 2001 was $49.6 million, or $0.36 per share.

During 2001, we recorded the effects of a number of events that impacted results of operations for that year. These events are as follows: (1) we incurred $137.8 million in pre-tax operating losses attributed to the former Roy Kay companies ($95.0 million after-tax, or $0.69 per share), primarily reflecting costs related to the discontinuance of the general contracting activities of these companies, costs to complete work on certain loss construction projects, as well as operating losses incurred. (See Note 10 to the Consolidated Financial Statements, "Roy Kay Operations" and Note 7 "Contractual Obligations, Financial Guarantees and Contingencies - Legal Matters", for a further discussion of these issues); (2) our gas exploration and production subsidiaries recorded a non-cash, pre-tax impairment charge of $42.0 million to recognize the effect of lower wellhead prices on their valuation of proved gas reserves. Our share of this charge was $26.2 million after-tax, or $0.19 per share. (See Note 1 to the Consolidated Financial Statements "Summary of Significant Accounting Policies," Item F for further details); and (3) following a favorable appellate court ruling, we reversed a previously recorded loss provision regarding certain pending rate refund issues relating to the 1989 RICO class action settlement of $20.1 million after-tax, or $0.15 per share. This adjustment has been reflected as a $22.0 million reduction to operations and maintenance expense and a reduction of $11.5 million to interest charges on the Consolidated Statement of Income for the year ended December 31, 2001. (See Note 11 to the Consolidated Financial Statements "Class Action Settlement" for a further discussion of this issue.)

Interest expense decreased $52.0 million in 2002 compared to 2001. The weighted-average interest rate on outstanding commercial paper for 2002 was approximately 2.0% compared to approximately 4.5% in 2001. Further, KeySpan had a number of interest rate swap agreements which effectively converted fixed rate debt to floating rate debt. The use of these derivative instruments reduced interest expense by $35.6 million in 2002. (See Note 8 to the Consolidated Financial Statements "Hedging, Derivative Financial Instruments, and Fair Values" for a description of these instruments.) Interest expense in 2001 reflects the reversal of $11.5 million in accrued interest expense resulting from the RICO class action settlement, as noted previously.

Income tax expense generally reflects the level of pre-tax income in 2002 and 2001. However, as noted above, during 2002 we finalized the valuation study related to the assets transferred to KeySpan resulting from the KeySpan/LILCO business combination completed in May 1998. As a result of an adjustment to deferred taxes and current income taxes payable, KeySpan recognized a $5.5 million income tax benefit. Income tax expense for 2002 also reflects additional tax benefits of approximately $15 million resulting from the finalization of amended tax returns and the reversal of certain tax reserves.

As a result of the above mentioned items, income from continuing operations, less preferred stock dividends, increased $153.8 million in 2002 compared to 2001; earnings per share from continuing operations increased $1.05 per share. Average common shares outstanding in 2002 increased by 2% compared to 2001 reflecting the re-issuance of shares held in treasury pursuant to dividend reinvestment and employee benefit plans. This increase in average common shares outstanding reduced earnings per share in 2002 by $0.06 compared to 2001.

Net income from gas exploration and production operations decreased by $13.4 million, or $0.11 per share, in 2002 compared to 2001. These operations were adversely impacted by significantly lower realized gas prices in 2002, particularly in the first quarter. As previously mentioned, these operations recorded a non-cash impairment charge in 2001; excluding this charge, the comparative decrease in earnings was $39.6 million, or $0.30 per share.

Financial Outlook for 2004

KeySpan's consolidated earnings for 2004 are forecasted to be in the range of $2.55 to $2.75 per share, excluding special items. Earnings from continuing core operations (defined for this purpose as all continuing operations other than exploration and production, less preferred stock dividends) are forecasted to be in the range of $2.20 to $2.30 per share, while earnings from exploration and production operations are forecasted to be in the range of $0.35 to $0.45 per share.

Consolidated earnings are seasonal in nature due to the significant contribution to earnings of our gas distribution operations. As a result, we expect to earn most of our annual earnings in the first and fourth quarters of our fiscal year.

Review of Operating Segments

In response to new disclosure regulations adopted by the Securities and Exchange Commission ("SEC") as part of its implementation of the Sarbanes-Oxley Act of 2002 – specifically Regulation G, which became effective March 2003 – we are reporting all of KeySpan's segment results on an Operating Income basis for 2003, 2002 and 2001. Management believes that this generally accepted accounting principle ("GAAP") based measure provides a reasonable indication of KeySpan's underlying performance associated with its operations. The following is a discussion of financial results achieved by KeySpan's operating segments presented on an Operating Income basis.

Gas Distribution

KeySpan Energy Delivery New York ("KEDNY") provides gas distribution service to customers in the New York City Boroughs of Brooklyn, Staten Island and a portion of Queens. KeySpan Energy Delivery Long Island ("KEDLI") provides gas distribution service to customers in the Long Island Counties of Nassau and Suffolk and the Rockaway Peninsula of Queens County. Four natural gas distribution companies - Boston Gas Company, Essex Gas Company, Colonial Gas Company and EnergyNorth Natural Gas, Inc., each doing business under the name KeySpan Energy Delivery New England ("KEDNE"), provide gas distribution service to customers in Massachusetts and New Hampshire.

The table below highlights certain significant financial data and operating statistics for the Gas Distribution segment for the periods indicated.

(In Thousands of Dollars)	2003	2002	2001
	Year Ended December 31,		
Revenues	$ 4,161,272	$ 3,163,761	$ 3,613,551
Cost of gas	2,444,485	1,569,325	2,017,782
Revenue taxes	90,456	83,066	119,084
Net Gas Revenues	1,626,331	1,511,370	1,476,685
Operating Expenses			
Operations and maintenance	659,932	608,266	593,341
Depreciation and amortization	259,934	237,186	253,523
Operating taxes	147,334	135,687	148,428
Total Operating Expenses	1,067,200	981,139	995,292
Gain on the sale of property	15,123	903	-
Operating Income	$ 574,254	$ 531,134	$ 481,393
Firm gas sales and transportation (MDTH)	328,073	284,281	283,081
Transportation - Electric Generation (MDTH)	34,778	64,173	64,578
Other Sales (MDTH)	158,722	209,002	188,037
Warmer (Colder) than Normal - New York & Long Island	(8.0%)	7.0%	10.0%
Warmer (Colder) than Normal - New England	(10.0%)	4.0%	4.6%

A MDTH is 10,000 therms and reflects the heating content of approximately one million cubic feet of gas. A therm reflects the heating content of approximately 100 cubic feet of gas. One billion cubic feet (BCF) of gas equals approximately 1,000 MDTH.

Net Revenues

Net gas revenues (revenues less the cost of gas and associated revenue taxes) from our gas distribution operations increased by $115.0 million, or 8%, for the year ended December 31, 2003, compared to last year. Both our New York and New England based gas distribution operations benefited from the significantly colder than normal weather experienced throughout the Northeastern United States, particularly during the primary winter heating months, January through March, when our gas distribution operations realize over 60% of their yearly operating income. As measured in heating degree-days, weather during the first quarter of 2003 was approximately 10% colder than normal in our New York and New England service territories. This contrasts with the extremely warm weather experienced during the first quarter of 2002 when weather was approximately 16% - 18% warmer than normal. On a twelve month basis, weather was approximately 8% - 10% colder than normal in 2003 compared to 4% - 7% warmer than normal in 2002.

Net gas revenues from firm gas customers (residential, commercial and industrial customers) in our New York service territories increased by $56.4 million, or 6%, for the twelve months ended December 31, 2003, compared to the same period last year. Customer additions and oil-to-gas conversions, net of attrition and conservation, added approximately $22 million to net revenues during 2003. The effect of higher customer consumption in 2003 due primarily to colder than normal weather, coupled with lower customer consumption in 2002 due to the extremely warmer than normal weather resulted in a comparative increase to firm net revenues of approximately $41.1 million in 2003 compared to 2002. However, KEDNY and KEDLI each operate under a utility tariff that contains a weather normalization adjustment that significantly offsets variations in firm net revenues due to fluctuations from normal weather. These tariff provisions resulted in a $20.4 million refund to firm gas customers during 2003. Also included in net revenues are regulatory incentives that reduced comparative net revenues by $2.1 million and recovery of certain taxes that added $15.8 million to net revenues during 2003. The recovery of taxes through revenues, however, does not impact net income since we expense a similar amount as amortization charges and income taxes, as appropriate, on the Consolidated Statement of Income.

Net gas revenues from firm gas customers in our New England service territories increased $31.7 million, or 7%, for the year ended December 31, 2003, compared to the same period last year. Customer additions and oil-to-gas conversions, net of attrition and conservation, added approximately $13.5 million to net revenues. As with our New York service territories, higher customer consumption in 2003 due to the colder than normal weather, coupled with lower customer consumption in 2002 due to the warmer than normal weather, resulted in an increase in comparative net revenues for our New England based gas distribution utilities of approximately $25.1 million in 2003 compared to 2002. The gas distribution operations of our New England based subsidiaries do not have a weather normalization adjustment. To mitigate the effect of fluctuations from normal weather patterns on KEDNE's results of operations and cash flows, weather derivatives were put in place for the 2002/2003 and 2003/2004 winter heating seasons. Since weather during the first quarter of 2003 was 10% colder than normal in the New England service territories, we recorded an $11.9 million reduction to revenues to reflect the loss on these derivative transactions. Similarly, in 2002 we recorded a $3.3 million reduction to revenues. As a result of these transactions, comparative net revenues were adversely impacted by $8.6 million. Weather derivatives had only a marginal impact on net revenues during the fourth quarter of 2003, since weather was approximately normal. (See Note 8 to the Consolidated Financial Statements "Hedging, Derivative Financial Instruments and Fair Values" for further information).

Also included in net revenues for 2003 are $5.6 million of base-rate adjustments resulting from Boston Gas Company's recently concluded rate case. Further, included in net revenues for 2002, was a benefit of $3.9 million as a result of a favorable ruling from the Massachusetts Supreme Judicial Court relating to the appeal by Boston Gas Company of its Performance Based Rate Plan ("PBR"). The net effect of these base-rate adjustments was a favorable impact to comparative net revenues in 2003 of $1.7 million. (See "Regulation and Rate Matters" for a further discussion of these matters.)

Firm gas distribution rates for KEDNY and KEDLI in 2003, other than for the recovery of gas costs, have remained substantially unchanged from rates charged last year. As noted, firm gas distribution rates for KEDNE reflect an increase of $5.6 million resulting from The Boston Gas Company's rate order, which became effective November 1, 2003.

In our large-volume heating and other interruptible (non-firm) markets, which include large apartment houses, government buildings and schools, gas service is provided under rates that are designed to compete with prices of alternative fuel, including No. 2 and No. 6 grade heating oil. Net revenues from sales to these markets increased by $26.8 million during the twelve months ended December 31, 2003, compared to the same period last year. The majority of interruptible profits earned by KEDNE and KEDLI are returned to firm customers as an offset to gas costs.

During 2002, combined net gas revenues from our gas distribution operations increased by $34.7 million, or 2% compared to 2001. Both the New York and New England based gas distribution operations were adversely impacted by the significantly warmer than normal weather experienced throughout the Northeastern United States during 2002, particularly during the first quarter. Weather during the primary heating seasons, January through March, was approximately 16%-18% warmer than normal, across our service territories.

Net revenues from firm gas customers in our New York service territories increased $13.6 million, or 1%, in 2002 compared to 2001. Included in net revenues are regulatory incentives and recovery of certain taxes that added $1.8 million and $20.1 million to net revenues during 2002, respectively. As mentioned previously, the recovery of taxes through revenues does not impact net income. Excluding both the regulatory incentives and tax recoveries, comparative net revenues decreased $8.3 million. During 2002, our New York based gas distribution utilities added approximately $40 million in gross gas load additions through oil-to-gas conversions, as well as from new construction. Further, as mentioned, KEDNY and KEDLI each operate under utility tariffs that contain a weather normalization adjustment. These tariff provisions resulted in an increase to net gas revenues of $22.3 million in 2002. However the benefits from load additions and the weather normalization adjustment were offset by declining usage per customer due to the extremely warm first quarter weather and the use of more efficient gas heating equipment. Additionally, the down-turn in the economy throughout the Northeastern United States adversely impacted gas consumption in 2002.

Net revenues from firm gas customers in the New England service territories increased by $20.5 million, or 5%, in 2002 compared to 2001, primarily as a result of approximately $24 million in gross load additions. Also included in net revenues are base rate adjustments totaling $10.0 million associated with Boston Gas Company's PBR. The largest component of this adjustment reflects the beneficial effect of a favorable ruling of the Massachusetts Supreme Judicial Court relating to the "accumulated inefficiencies" component of the productivity factor in the PBR. This ruling resulted in a benefit to comparative net margins of $6.3 million. (See "Regulation and Rate Matters" for a further discussion of this matter.) Offsetting, to some extent, these benefits to revenues were the adverse effects of declining usage per customer due to the extremely warm first quarter weather and the use of more efficient gas heating equipment. Additionally, the down-turn in the economy throughout the Northeastern United States adversely impacted gas consumption in 2002.

As mentioned previously, the New England-based gas distribution subsidiaries do not have weather normalization adjustments. To lessen, to some extent, the effect of fluctuations from normal weather patterns on KEDNE's results of operations and cash flows, weather derivatives were in place for the 2002/2003 winter heating season. Since weather during the fourth quarter of 2002 was 7% colder than normal in the New England service territories, we recorded a $3.3 million reduction to revenues to reflect the loss on these derivative transactions. (See Note 8 to the Consolidated Financial Statements "Hedging, Derivative Financial Instruments, and Fair Values" for further information).

Firm gas distribution rates in 2002, excluding gas cost recoveries, remained substantially unchanged from 2001 in all of our service territories.

Net revenues from sales in the large-volume heating and other interruptible (non-firm) markets were consistent between 2002 and 2001.

We are committed to our expansion strategy initiated during the past few years. We believe that significant growth opportunities exist on Long Island and in our New England service territories. We estimate that on Long Island approximately 36% of the residential and multi-family markets, and approximately 58% of the commercial market currently use natural gas for space heating. Further, we estimate that in our New England service territories approximately 53% of the residential and multi-family markets, and approximately 63% of the commercial market, currently use natural gas for space heating purposes. We will continue to seek growth in all our market segments, through the economic expansion of our gas distribution system, as well as through the conversion of residential homes from oil-to-gas for space heating purposes and the pursuit of opportunities to grow the multi-family, industrial and commercial markets.

Firm Sales, Transportation and Other Quantities

Total actual firm gas sales and transportation quantities increased by 15% during the year ended December 31, 2003, compared to the same period in 2002. In the New York service territories actual firm sales increased 17%, while firm sales in the New England service territories increased 13%. Weather normalized sales quantities increased 6% in the New York service territories and 3% in the New England service territories. The increases in both actual and weather normalized gas sale quantities reflect higher customer consumption as a result of the significantly colder than normal weather in 2003, as well as from customer additions and oil-to-gas conversions for space heating purposes. Further, as mentioned previously, gas sales quantities in 2002 were adversely impacted by the exceptionally warm weather.

In 2002, total actual firm gas sales and transportation quantities remained consistent with 2001. In the New York service territories, actual and weather normalized firm gas sales and transportation quantities decreased slightly in 2002 compared to 2001, due to the exceptionally warm 2002 weather. However, in the New England services territories, firm gas sales and transportation quantities increased 4%, despite the warm first quarter weather, due to load additions.

Net revenues are not affected by customers opting to purchase their gas supply from other sources, since delivery rates charged to transportation customers generally are the same as delivery rates charged to sales service customers. Transportation quantities related to electric generation reflect the transportation of gas to our electric generating facilities located on Long Island. Net revenues from these services are not material.

Other sales quantities include on-system interruptible quantities, off-system sales quantities (sales made to customers outside of our service territories) and related transportation. We have an agreement with Coral Resources, L.P. ("Coral"), a subsidiary of Shell Oil Company, under which Coral assists in the origination, structuring, valuation and execution of energy-related transactions on behalf of KEDNY and KEDLI. We also have a portfolio management contract with Entergy Koch Trading, LP ("EKT"), under which EKT provides all of the city gate supply requirements at market prices and manages certain upstream capacity, underground storage and term supply contracts for KEDNE. These agreements expire on March 31, 2006.

Purchased Gas for Resale

The increase in gas costs for the year ended December 31, 2003 compared to the same period in 2002 of $875.2 million, or 56%, reflects an increase of 39% in the price per dekatherm of gas purchased, and a 15% increase in the quantity of gas purchased. The decrease in gas costs in 2002 compared to 2001 of $448.5 million, or 22%, reflects a decrease of 26% in the price per dekatherm of gas purchased, partially offset by a 1.0% increase in the quantity of gas purchased. The current gas rate structure of each of our gas distribution utilities includes a purchased gas adjustment clause, pursuant to which variations between actual gas costs incurred for resale to firm sales customers and gas costs billed to firm sales customers are deferred and refunded to or collected from customers in a subsequent period.

Operating Expenses

Operating expenses in 2003 increased $86.1 million, or 9%, compared to last year. This increase is primarily attributable to higher pension and other postretirement benefit costs, which have increased (net of amounts deferred and subject to regulatory true-ups) by $30.9 million during 2003. The cost of these benefits has risen primarily as a result of lower actual returns on plan assets, as well as increased health care costs. Further, the colder weather experienced during 2003 resulted in a higher level of repair and maintenance work on our gas distribution infrastructure which increased comparative operating expenses by approximately $15 million.

Higher depreciation and amortization expense reflects the continued expansion of the gas distribution system. Further, included in depreciation and amortization expense is the amortization of certain property taxes previously deferred and currently being recovered in revenues. Comparative operating taxes reflect a favorable $9.9 million adjustment recorded during 2002 relating to the reversal of excess tax reserves established for the KeySpan/LILCO combination in May 1998.

Operating expenses decreased by $14.2 million in 2002 compared to 2001. Comparative operating expenses were significantly impacted by the discontinuation of goodwill amortization. As mentioned earlier, in January 2002, we adopted SFAS 142 “Goodwill and Other Intangible Assets,” which required, among other things, the discontinuation of goodwill amortization. Goodwill amortization in the gas distribution segment for the twelve months ended December 31, 2001 was $35.6 million. Excluding the effects of this amortization, operating expenses increased by $21.4 million, or 2%, in 2002 compared to 2001.

The increase in operating expense in 2002 is attributable, in part, to higher pension and other postretirement benefits which increased by approximately $25 million, net of amounts deferred and subject to regulatory true-ups, over the level incurred in 2001. Further, depreciation and amortization expense, excluding the 2001 goodwill amortization, increased as a result of the continued expansion of the gas distribution system.

Offsetting, to some extent, these increases to operating expenses is the favorable $9.9 million adjustment to operating taxes recorded in 2002 related to the reversal of certain operating tax reserves established for the KeySpan/LILCO combination as previously noted. Further, we realized cost saving synergies as a result of early retirement and severance programs implemented in the fourth quarter of 2000. The early retirement portion of the program was completed in 2000, but the severance feature continued through 2002.

Sale of Property

During 2003 we recorded $15.1 million in gains from property sales, primarily 550 acres of real property located on Long Island.

Other Matters

As previously mentioned, there remain significant growth opportunities in our Long Island and New England gas distribution service areas. The Northeast region represents a significant portion of the country's population and energy consumption. Cost efficient gas sales growth and customer additions are critical to our earnings in the future. However, the beneficial effect of our growth initiatives may not be fully realized in the short-term since we will continue to make incremental investments in our gas distribution network to optimize the long-term growth opportunities in our service territories.

In order to serve the anticipated market requirements in our New York service territories, KeySpan and Duke Energy Corporation formed Islander East Pipeline Company, LLC ("Islander East") in 2000. Islander East is owned 50% by KeySpan and 50% by Duke Energy, and was created to pursue the authorization and construction of an interstate pipeline from Connecticut, across Long Island Sound, to a terminus near Northport, Long Island. Applications for all necessary regulatory authorizations were filed in 2000 and 2001. To date, Islander East has received a final certificate from the Federal Energy Regulatory Commission ("FERC") and all necessary permits from the State of New York. However, the State of Connecticut has denied Islander East's application for a coastal zone management permit and a permit under Section 401 of the Clean Water Act. Islander East has reinstated its appeal of the State of Connecticut's determination on the coastal zone management issue to the United States Department of Commerce and is evaluating its legal and other options with respect to the Section 401 issue. Once in service, the pipeline is expected to transport up to 260,000 DTH daily to the Long Island and New York City energy markets, enough natural gas to heat 600,000 homes. The pipeline will also allow KeySpan to diversify the geographic sources of its gas supply. However, we are unable to predict when or if all regulatory approvals required to construct this pipeline will be obtained. Various options for the financing of pipeline construction are currently being evaluated. At December 31, 2003, total expenditures associated with the siting and permitting of the Islander East pipeline were $14.9 million.

Electric Services

The Electric Services segment primarily consists of subsidiaries that own and operate oil and gas fired electric generating plants in the New York City Borough of Queens (the "Ravenswood facility") and the counties of Nassau and Suffolk on Long Island and on the Rockaway Peninsula in Queens. In addition, through long-term contracts of varying lengths, we manage the electric transmission and distribution ("T&D") system, the fuel and electric purchases, and the off-system electric sales for LIPA.

Selected financial data for the Electric Services segment is set forth in the table below for the periods indicated.

	Year Ended December 31,		
(In Thousands of Dollars)	2003	2002	2001
Revenues	$1,503,187	$1,421,143	$1,421,179
Purchased fuel	371,134	272,873	281,398
Net Revenues	1,132,053	1,148,270	1,139,781
Operating Expenses			
Operations and maintenance	650,649	659,882	662,083
Depreciation	66,843	61,377	52,284
Operating taxes	145,584	139,694	155,693
Total Operating Expenses	863,076	860,953	870,060
Gain on the sale of property	-	1,479	-
Operating Income	$ 268,977	$ 288,796	$ 269,721
Electric sales (MWH)*	4,743,029	4,998,111	4,932,836
Capacity(MW)*	2,200	2,200	2,200
Cooling degree days	1,010	1,384	1,381

*Reflects the operations of the Ravenswood facility only.

Net Revenues

Total electric net revenues decreased $16.2 million, or 1% for the year ended December 31, 2003 compared to the same period in 2002.

Net revenues from the Ravenswood facility were $3.1 million lower in 2003 compared to 2002. Comparative net revenues reflect higher capacity revenues of $31.5 million, offset by a decrease in energy margins of $34.6 million. The increase in capacity revenues reflects an increase in the level of capacity sold, as well as an increase in the selling price of capacity. Such increases are the result of two measures. First, in 2002, the New York Independent System Operator ("NYISO") employed a revised methodology to assess the available supply of and demand for installed capacity. This revised methodology resulted in insufficient capacity being procured by the market, which caused a reliability concern. Further, the revised methodology resulted in lower capacity volume sold into the NYISO and depressed capacity pricing during the year ended December 31, 2002. The NYISO, however, recognized a calculation flaw in its revised methodology, and prior to the 2002/2003 winter season capacity auction, corrected the calculation methodology to ensure that sufficient capacity is procured. Elimination of the flaw ensured compliance with New York State reliability rules and resulted in higher capacity revenue realized at the Ravenswood facility in 2003 compared to the prior year.

In addition, on May 20, 2003, the Federal Energy Regulatory Commission ("FERC") approved the NYISO's revised capacity market procurement design with an effective date of May 21, 2003. This revised capacity market procurement design is based on a demand curve rather than relying on deficiency auctions to procure necessary capacity. The deficiency auction with its associated fixed minimum capacity requirements was replaced with a spot market auction that pays gradually declining prices as additional capacity is offered and gradually increasing prices as capacity offers decrease. This new market design recognizes the value of capacity in excess of the minimum requirement and reduces price spikes during periods of shortage. Essentially, the demand curve design eliminates the high and low cycles inherent in the deficiency auction market design. This new market design also established seasonal electric generator specific price caps. Price caps establish the maximum price per megawatt ("MW") that capacity can be sold into the NYISO by divested electric generators like Ravenswood. Prior to this design change, one price cap was established for the entire year and was effective for all electric generators. For the Ravenswood facility, its 2003 summer price cap was higher than the yearly price cap effective during the 2002 summer. As a result of these market design changes, the Ravenswood facility realized higher capacity revenues during 2003 compared to 2002. It should be noted, however, that Ravenswood's 2003/2004 structured winter price cap will be lower than the yearly price cap effective during the 2002/2003 winter, which was prior to the implementation of the new demand curve methodology.

The decrease in comparative energy margins in 2003 primarily reflects significantly cooler weather during the summer of 2003 compared to the summer of 2002. Measured in cooling degree-days, weather for 2003 was 27% cooler than last year. The cooler weather resulted in lower realized "spark-spreads" (the selling price of electricity less cost of fuel, plus hedging gains or losses), as well as a reduction in megawatt hours sold into the NYISO. Further, more competitive behavior by market participants that bid into the NYISO, as well as certain price mitigation measures imposed by the FERC (as discussed below) have resulted in lower comparative realized "spark-spreads." Energy sales quantities during a portion of 2003 were also adversely impacted by the scheduled major overhaul of our largest generating unit.

We employ derivative financial hedging instruments to hedge the cash flow variability for a portion of forecasted purchases of natural gas and fuel oil consumed at the Ravenswood facility. Further, we have engaged in the use of derivative financial hedging instruments to hedge the cash flow variability associated with a portion of forecasted peak electric energy sales from the Ravenswood facility. These derivative instruments resulted in hedging gains, which are reflected in net electric margins, of $12.3 million for the year ended December 31, 2003 compared to hedging gains of $17.4 million for the year ended December 31, 2002. (See Note 8 to the Consolidated Financial Statements "Hedging, Derivative Financial Instruments, and Fair Values" for further information).

The rules and regulations for capacity, energy sales and the sale of certain ancillary services to the NYISO energy markets continue to evolve and the FERC has adopted several price mitigation measures that have adversely impacted earnings from the Ravenswood facility. Certain of these mitigation measures are still subject to rehearing and possible judicial review. The final resolution of these issues and their effect on our financial position, results of operations and cash flows cannot be fully determined at this time. (See the discussion under the caption "Market and Credit Risk Management Activities" for more information.)

Net revenues from the service agreements with LIPA decreased by $22.7 million for the year ended December 31, 2003 compared to the same period last year. Included in revenues are billings to LIPA for certain third party costs that were lower than such billings last year. These revenues have minimal or no impact on earnings since we record a similar amount of costs in operating expense and we share any cost under-runs with LIPA. Excluding these third party billings, revenues in 2003 associated with these service agreements increased approximately $7 million compared to last year. The increase reflects a higher level of service fees charged to

LIPA for the recovery of past operating costs. In 2003 we earned $16.2 million associated with non-cost performance incentives provided for under these agreements, compared to $16.0 million earned last year. (For a description of the LIPA Agreements, see the discussion under the caption "LIPA Agreements.")

Net revenues from the new electric "peaking" facilities located at Glenwood Landing and Port Jefferson on Long Island were $9.6 million higher in 2003 compared to 2002, reflecting a full year of operation. The Glenwood facility was placed in service on June 1, 2002, while the Port Jefferson facility was placed in service on July 1, 2002. These facilities added a combined 160 megawatts of generating capacity to KeySpan's electric generation portfolio. The capacity of and energy produced by these facilities are dedicated to LIPA under 25 year contracts.

Total electric net revenues increased by $8.5 million for the year ended December 31, 2002, compared to the same period in 2001. Net revenues in 2002 reflect net revenues of $17.3 million from the Glenwood Landing and Port Jefferson facilities.

Net revenues from the LIPA Agreements increased by $47.2 million in 2002, compared to 2001. Included in revenues for 2002, are billings to LIPA for certain third party costs that were significantly higher than such billings in the prior year. As previously mentioned, these revenues have minimal impact on earnings. Excluding these third party billings, revenues for 2002 associated with the LIPA Agreements were comparable to such revenues in 2001. In 2002 we earned $16.0 million associated with non-cost performance incentives provided for under these agreements, compared to $16.2 million earned in 2001.

Net revenues from the Ravenswood facility were $56 million, or 16%, lower in 2002, compared to 2001. Net revenues from capacity sales decreased $45.3 million compared to 2001, while margins associated with the sale of electric energy decreased $10.7 million. During 2002 we changed our classification of certain operating taxes that resulted in a comparative decrease in energy margins. Further, comparative energy sales were adversely impacted by a reduction in "spark-spread." Measured in cooling degree-days, weather during 2002 and 2001 was comparable.

The decrease in net revenues from capacity sales in 2002 was due, in part, to more competitive pricing by the electric generators that bid into the NYISO energy market which lowered capacity clearing prices by approximately 8% compared to 2001. Further, as mentioned earlier, the NYISO revised its methodology employed to determine the available supply of and demand for installed capacity that also had an adverse impact on the capacity market by reducing the capacity required to be purchased by load serving entities such as electric utilities.

Derivative instruments resulted in hedging gains, which are reflected in net electric margins, of $17.4 million for the year ended December 31, 2002 compared to hedging gains of $16.7 million for the year ended December 31, 2001. (See Note 8 to the Consolidated Financial Statements "Hedging, Derivative Financial Instruments, and Fair Values" for further information).

Operating Expenses

Operating expenses increased $2.1 million for the year ended December 31, 2003, compared to 2002. Included in comparative operating expenses is a decrease in third party capital costs that are fully recoverable from LIPA, as noted previously. Excluding the decrease in these costs, operating expenses increased approximately $32 million. This increase resulted, in part, from higher pension and other postretirement benefit costs. LIPA reimburses KeySpan for costs directly incurred by KeySpan in providing service to LIPA, subject to certain sharing provisions. Variations between pension and other postretirement costs and the estimates used to bill LIPA are deferred and refunded to or collected from LIPA in subsequent periods. As a result of an adjustment recorded in 2002 relating to this "true-up," comparative pension and other postretirement costs were approximately $9.3 million higher in 2003 compared to 2002. In addition, in 2002 we settled certain outstanding issues with LIPA and The Consolidated Edison Company of New York ("Consolidated Edison") that resulted in a $13.0 million decrease to operating expenses in 2002. Operating taxes reflect an increase in property tax rates associated with the Ravenswood facility. The increase in depreciation expense is associated with the Glenwood and Port Jefferson facilities.

Operating expenses were $9.1 million lower in 2002 compared to 2001. Excluding the increase in third party capital costs, operating expenses decreased by approximately $57 million in 2002 compared to 2001. As a result of an adjustment recorded in 2002 relating to the pension and other postretirement benefit "true-up" as previously mentioned, comparative pension and other postretirement costs were approximately $23 million lower in 2002 compared to 2001. Further, during 2002 we settled certain outstanding issues with LIPA and Consolidated Edison, as previously noted, that resulted in a $20.3 million decrease to comparative operating expenses. Also in 2002 we changed our method for recording certain operating taxes that resulted in a comparative decrease in operating taxes. The increase in depreciation and amortization expense primarily reflects depreciation associated with the new peaking facilities.

Other Matters

During 2002, construction began on a new 250 MW combined cycle generating facility at the Ravenswood facility site. The new facility was synchronized to the electric grid in December 2003 and commenced operational testing in January 2004. In March, the facility completed full load Dependable Maximum Net Capacity testing. The capacity and energy produced from this plant are anticipated to be sold into the NYISO energy markets during the second quarter of 2004. KeySpan intends to enter into an approximately $360 million sale/leaseback transaction with third parties to finance the cost of this facility. (See Note 15 to the Consolidated Financial Statements "Subsequent Events" for a further discussion regarding this proposed transaction.)

In 2003, the New York State Board on Electric Generation Siting and the Environment issued an opinion and order which granted a certificate of environmental capability and public need for a 250 MW combined cycle electric generating facility in Melville, Long Island, which is now final and non-appealable. Also in 2003, LIPA issued a Request for Proposal ("RFP") seeking bids from developers to either build and operate a Long Island generating facility, and/or a new cable that will link Long Island to dedicated off-Long Island power of between 250 to 600 MW of electricity by no later than the summer of 2007. KeySpan and American National Power Inc.

("ANP") filed a joint proposal in response to LIPA's RFP. Under the proposal, KeySpan and ANP will jointly own and operate two 250 MW electric generating facilities to be located on Long Island. It is anticipated that LIPA will respond to the joint proposal early in 2004. At December 31, 2003, total expenditures associated with the siting, permitting and construction of the Ravenswood expansion project, and the siting, permitting and procurement of equipment for the Long Island 250 MW combined cycle electric generating facility were $387.7 million.

As part of our growth strategy, we continually evaluate the possible acquisition and development of additional generating facilities in the Northeast. However, we are unable to predict when or if any such facilities will be acquired and the effect any such acquired facilities will have on our financial condition, results of operations or cash flows.

Energy Services

The Energy Services segment includes companies that provide services to clients located primarily within the Northeastern United States, with concentrations in the New York City metropolitan area, including New Jersey and Connecticut, as well as in Rhode Island, Pennsylvania, Massachusetts and New Hampshire. The primary lines of business are: Business Solutions and Home Energy Services.

The table below highlights selected financial information for the Energy Services segment.

	Year Ended December 31,		
(In Thousands of Dollars)	2003	2002	2001
Revenues	$ 649,590	$ 938,761	$ 1,100,167
Less: cost of gas and fuel	93,674	206,731	407,734
Net Revenues	555,916	732,030	692,433
Other operating expenses	593,982	743,965	839,918
Operating (Loss)	$ (38,066)	$ (11,935)	$ (147,485)

Revenues decreased 31% for the year ended December 31, 2003 compared to the same period last year, due in part to lower revenues realized by the Business Solutions group of companies as a result of the softness in the construction industry in the Northeastern United States, as well as from the discontinuation of the general contracting business of one of our subsidiaries. The Business Solutions group of companies provide mechanical, contracting, plumbing, engineering, and consulting services to commercial, institutional, and industrial customers. Further, comparative revenues, as well as gas and fuel costs, were impacted by the assignment of retail natural gas customers, consisting mostly of residential and small commercial customers, to ECONnergy Energy Co., Inc. ("ECONnergy). KeySpan Energy Services will continue its electric marketing activities.

Total operating losses for the Energy Services segment increased $26.1 million in 2003 compared to 2002. Operating losses for the Business Solutions group of companies increased by $32.2 million, reflecting revenue and significant gross margin pressure from the softness in the construction industry, which has delayed the start-up of certain engineering and construction projects, and has generally increased competition for remaining opportunities. In addition, margins were impacted by certain project-specific losses, resulting from costs incurred in excess of cost recoveries, for which some recovery may be possible pending successful claim resolution. Business Solutions' backlog held relatively stable at approximately $537 million at December 31, 2003 (which includes backlog of $33 million purchased in a recent acquisition as discussed below), compared to $514 million at December 31, 2002.

Offsetting, in part, the results of the Business Solutions group of companies, was a comparative increase in operating earnings of $6.1 million for the year ended December 31, 2003 associated with the Home Energy Services group of companies. These companies provide residential and small commercial customers with service and maintenance contracts, as well as the retail marketing of electricity. Comparative operating income reflects losses incurred during 2002, resulting from the non-renewal of appliance service contracts due to the warm first quarter 2002 weather, as well as from an increase in the provision for bad debts.

Comparative operating income results for 2002 compared to 2001 were significantly impacted by losses incurred by one of our subsidiaries. In 2001, we discontinued the general contracting activities related to the former Roy Kay companies, with the exception of completion of work on then existing contracts. (See Note 10 to the Consolidated Financial Statements "Roy Kay Operations" for a more detailed discussion.) For the year ended December 31, 2001, we incurred an operating loss of $137.8 million associated with the operations of the former Roy Kay companies. The Roy Kay results reflect costs related to the discontinuation of the general contracting activities of these companies, costs to complete work on certain loss construction projects, as well as operating losses. During 2002, in completing the contracts entered into by the former Roy Kay companies we incurred operating losses of $10.8 million reflecting increases in costs to complete construction contracts, and general and administrative expenses. It should be noted that in 2003 we incurred $11.4 million in operating losses which reflected provisions made for the resolution of outstanding claims and change orders, as well as additional costs incurred in connection with the collection of outstanding contract balances.

Excluding the results of the former Roy Kay companies, the Energy Services segment reflected an increase in operating income of $8.7 million in 2002 compared to 2001. Revenues, excluding the Roy Kay companies, decreased by $180.4 million in 2002, while the cost of fuel decreased by $201.0 million. These declines, which for the most part offset each other, reflect the operations of our gas and electric marketing subsidiary. In 2002, this subsidiary substantially decreased its customer base by focusing its marketing efforts on higher net margin customers and in 2003 assigned the majority of its retail natural gas customers to ECONnergy, as previously discussed.

Operating income for the Business Solutions group of companies improved by $22.0 million in 2002 compared to 2001. This increase reflected additional work being performed on the backlog of projects existing at the end of 2001 and the absence of $6 million in losses incurred on four major projects in 2001. A backlog of approximately $514 million existed at December 31, 2002, which was 20% below the December 31, 2001 level.

Offsetting the positive contribution to operating income in 2002 by the Business Solutions group of companies was a decrease of $13.3 million associated with the Home Energy Services group of companies. Contributing to the decrease in operating income from Home Energy Services were the following factors: (i) the adverse impact of the downturn in the economy in 2002; (ii) the non-renewal of appliance service contracts due to the warm first quarter weather; (iii) costs associated with the closing of a service center; and (iv) an increase in the reserve for bad debts. Comparative operating income in 2002 also benefited from the elimination of goodwill amortization, which for 2001 amounted to $8.2 million.

Other Matters

During the third quarter of 2003, KeySpan Services, Inc., and its wholly-owned subsidiary, Paulus, Sokolowski and Sartor, LLC., acquired Bard, Rao + Athanas Consulting Engineers, Inc. (BR+A), a company engaged in the business of providing engineering services relating to mechanical, electrical and plumbing systems. The purchase price was $35 million, plus up to $14.7 million in contingent consideration depending on the financial performance of BR+A over the five-year period after the closing of the acquisition. We have recorded goodwill of $26 million and intangible assets of $2 million associated with this transaction. The intangible assets, which relate primarily to a portion of the backlog purchased, as well as to non-compete agreements with all of the former owners of BR+A, will be amortized over two and three years, respectively.

Energy Investments

The Energy Investment segment consists of our gas exploration and production operations, certain other domestic and international energy-related investments, as well as certain technology-related investments. Our gas exploration and production subsidiaries, Houston Exploration and KeySpan Exploration and Production, LLC ("KES E&P") are engaged in gas and oil exploration and production, and the development and acquisition of domestic natural gas and oil properties. In line with our strategy of monetizing or divesting certain non-core assets, in 2002 we sold a portion of our assets in the joint venture drilling program with Houston Exploration that was initiated in 1999. In 2003 we reduced our ownership interest in Houston Exploration to approximately 55% (from the previous level of 66%) through the repurchase, by Houston Exploration, of three million shares of common stock owned by KeySpan. The net proceeds of approximately $79 million received in connection with this repurchase were used to pay down short-term debt. We realized a $19.0 million gain on this transaction that was recorded in other income and (deductions) in the Consolidated Statement of Income. Income taxes were not provided on this transaction, since the transaction was structured as a return of capital.

In 2003, Houston Exploration acquired the entire Gulf of Mexico shallow-water asset base of Transworld Exploration and Production, Inc. for $149 million. The properties, which are 75% natural gas, have proven reserves of approximately 92 billion cubic feet of natural gas equivalent. Current production from 11 fields is approximately 35 million cubic feet of natural gas equivalent per day. Houston Exploration funded the transaction from its bank revolver and from cash on hand at the time of closing.

Selected financial data and operating statistics for our gas exploration and production activities is set forth in the following table for the periods indicated.

(In Thousands of Dollars)	Year Ended December 31, 2003	2002	2001
Revenues	$ 501,255	$ 357,451	$ 400,031
Depletion and amortization expense	204,102	176,925	142,728
Full cost ceiling test write-down	-	-	41,989
Other operating expenses	99,944	70,267	55,653
Operating Income	$ 197,209	$ 110,259	$ 159,661
Natural gas and oil production (Mmcf)	109,211	106,044	93,968
Natural gas (per Mcf) realized	$ 4.55	$ 3.32	$ 4.24
Natural gas (per Mcf) unhedged	$ 5.23	$ 3.16	$ 4.09

*Operating income above represents 100% of our gas exploration and production subsidiaries' results for the periods indicated. Gas reserves and production are stated in BCFe and Mmcfe, which includes equivalent oil reserves

Operating Income

The increase in operating income of $87.0 million or 79% for the year ended December 31, 2003, compared to the same period of 2002, reflects a significant increase in revenues. The higher revenues were offset, to some extent, by an increase in operating expenses associated with a higher depletion rate, as well as higher lease operating expenses and severance taxes, as discussed below. Revenues for the year ended 2003 benefited from the combination of a 37% increase in average realized gas prices (average wellhead price received for production including hedging gains and losses) and a 3% increase in production volumes.

Derivative financial hedging instruments are employed by Houston Exploration to provide more predictable cash flow, as well as to reduce its exposure to fluctuations in natural gas prices. The average realized gas price for the year ended 2003 was 87% of the average unhedged natural gas price, resulting in revenues that were approximately $67 million lower than revenues that would have been achieved if derivative financial instruments had not been in place during 2003. Houston Exploration hedged slightly less than 70% of its 2003 production, principally through the use of costless collars, and has hedged a similar amount of its estimated 2004 production. Further, at December 31, 2003, Houston Exploration has derivative financial instruments in place for approximately 44% of its estimated 2005 production. (See Note 8 to the Consolidated Financial Statements, “Hedging, Derivative Financial Instruments, and Fair Values” for further information.)

The depletion rate experienced in 2003 was $1.85 per Mcf, compared to $1.68 per Mcf experienced in 2002. The increase in the depletion rate reflects downward reserve revisions related to performance, the addition of more costs to Houston Exploration’s depreciation base with fewer additions for reserves, as well as an increase in estimated future development costs at year end.

The increase in other operating expenses for the year ended December 31, 2003, compared to the same period of 2002 was primarily due to increased lease operating costs and severance taxes. Lease operating expenses increased $13.1 million in 2003 compared to 2002, as a result of the continued expansion of operations both onshore and offshore. Severance tax, which is a function of volume and revenues generated from onshore production, increased $6.5 million in 2003 compared to 2002 as a result of the increase in average wellhead prices for natural gas. Overall operating expenses are increasing as new wells and facilities are added and production from existing wells is maintained.

Operating income decreased $49.4 million or 31% in 2002 compared to 2001 primarily due to a 22% reduction in average realized gas prices, which lowered comparative revenues. Further, operating expenses increased as a result of higher levels of production and a higher depletion rate, as well as from an increase in lease operating expenses. The adverse effect on revenues resulting from the decline in average realized gas prices was partially offset by an increase of 13% in production volumes.

The average realized gas price for 2002 was 105% of the average unhedged natural gas price, resulting in revenues that were approximately $16 million higher than revenues that would have been achieved if derivative financial instruments had not been in place during 2002. Houston Exploration hedged approximately 64% of its 2002 production, principally through the use of costless collars.

The depletion rate was $1.68 per Mcf for the year ended December 31, 2002, compared to $1.49 per Mcf for the same period in 2001, reflecting higher finding and development costs together with the addition of fewer new reserves.

In 2001, our gas exploration and production subsidiaries recorded a non-cash impairment charge of $42.0 million to recognize the effect of lower wellhead prices on their valuation of proved gas reserves. Our share of this charge, which includes our joint venture ownership interest and minority interest, was $26.2 million after-tax. (See Note 1 to the Consolidated Financial Statements "Summary of Significant Accounting Policies," Item F for more information on this charge.)

Natural gas prices continue to be volatile and the risk that we may be required to record an impairment charge on our full cost pool again in the future increases when natural gas prices are depressed or if we have significant downward revisions in our estimated proved reserves.

The table below indicates the net proved reserves of our gas exploration and production subsidiaries for the periods indicated.

	Year Ended December 31,					
	2003		2002		2001	
	BCFe	%	BCFe	%	BCFe	%
Houston Exploration	755	99.1%	650	96.7%	608	94.0%
KSE E&P	7	0.9%	22	3.3%	39	6.0%
Total	762	100.0%	672	100.0%	647	100.0%

This segment also consists of KeySpan Canada; our 20% interest in Iroquois Gas Transmission System LP ("Iroquois"); our wholly owned 600,000 barrel liquefied natural gas ("LNG") storage and receiving facility located in Rhode Island ("KeySpan LNG"); and our 50% interest in Premier Transmission Limited, and until December 2003, our 24.5% interest in Phoenix Natural Gas Limited, both located in Northern Ireland.

Selected financial data for our other energy-related investments is set forth in the following table for the periods indicated.

(In Thousands of Dollars)	Year Ended December 31, 2003	2002	2001
Revenues	$ 113,124	$ 90,778	$ 98,287
Less: Operation and maintenance expense	68,568	57,161	71,411
Other operating expenses	22,317	17,622	20,883
Add: Equity earnings	19,106	13,992	13,129
Gain on sale of property	-	2,348	-
Operating Income	$ 41,345	$ 32,335	$ 19,122

** Operating income above reflects 100% of KeySpan's Canada's results.*

The increase in operating income in 2003 compared to last year reflects, in part, higher operating income associated with our Canadian investments, primarily KeySpan Canada, as well as higher earnings from our Northern Ireland investments. KeySpan Canada experienced higher unit sales, as well as higher quantities of sales of natural gas liquids in 2003, as a result of increasing oil prices. The pricing of natural gas liquids is directly related to oil prices. The Northern Ireland investments realized higher gas sales quantities, as well as favorable exchange rates during 2003. Operating income for 2003 also reflects our investment in KeySpan LNG storage facility located in Rhode Island, which we acquired in December 2002.

The increase in operating income in 2002 compared to 2001 reflects lower comparative losses associated with certain technology-related investments. Further, higher operating income from our Northern Ireland investments were, for the most part, offset by lower earnings realized by KeySpan Canada. KeySpan Canada experienced lower per unit sales prices, as well as lower quantities of sales of natural gas liquids in 2002, as a result of generally lower oil prices.

KeySpan has announced an initiative to upgrade the storage and receiving terminal and enhance the vaporization capacity at the KeySpan LNG facility located in Providence, Rhode Island. Pending approvals, the facility could be ready to accept marine deliveries by 2005. We anticipate making an investment of approximately $50 million to upgrade the facility.

We do not consider certain businesses contained in the Energy Investments segment to be part of our core asset group. We have stated in the past that we may sell or otherwise dispose of all or a portion of our non-core assets. As previously indicated, in 2003 we monetized 39.09% of our interest in KeySpan Canada, a company with natural gas processing plants and gathering facilities in Western Canada. These assets include 14 processing plants and associated gathering systems that can process approximately 1.5 BCFe of natural gas daily and provide associated natural gas liquids fractionation. We sold a portion of our interest in KeySpan Canada through the establishment of an open-ended income fund trust (the "Fund") organized under the laws of Alberta, Canada. The Fund acquired the 39.09% ownership interest of KeySpan Canada through an indirect subsidiary, and then issued 17 million trust units to the public through an initial public offering. Each trust unit represents a beneficial interest in the Fund and is registered on the Toronto Stock Exchange (KEY.UN). Additionally, we sold our 20% interest in Taylor NGL LP that owns and operates two extraction plants in Canada to AltaGas Services, Inc. We received cash proceeds of $119.4 million associated with these transactions and recorded a pre-tax loss of

$30.3 million ($34.1 million after-tax). In February 2004, KeySpan entered into an agreement to sell an additional 36% of its interest in KeySpan Canada. (See Note 15 to the Consolidated Financial Statements, "Subsequent Events.")

Further, in the fourth quarter of 2003, we completed the sale of our 24.5% interest in Phoenix Natural Gas Limited. We received cash proceeds of $96 million and recorded a pre-tax gain of $24.7 million, $16.0 million after-tax, or $0.10 per share.

Based on current market conditions we cannot predict when, or if, any other sales or dispositions of our non-core assets may take place, or the effect that any such sale or disposition may have on our financial position, results of operations or cash flows.

Allocated Costs

As previously mentioned, we are subject to the jurisdiction of the SEC under PUHCA. As part of the regulatory provisions of PUHCA, the SEC regulates various transactions among affiliates within a holding company system. In accordance with the regulations of PUHCA and the New York State Public Service Commission requirements, we have non-operating service companies that provide: (i) traditional corporate and administrative services; (ii) gas and electric transmission and distribution systems planning, marketing, and gas supply planning and procurement; and (iii) engineering and surveying services to subsidiaries. Revised allocation methodologies, approved by the SEC, have been in use since 2001, to allocate certain service company costs to affiliates.

The variation in operating income reflected in "eliminations and other" for KeySpan's non-operating subsidiaries between 2003 and 2002 primarily reflects an adjustment recorded in 2003 for environmental reserves associated with non-utility environmental sites based on a recently concluded site investigation study. (See Note 7 to the Consolidated Financial Statements "Contractual Obligations, Financial Guarantees and Contingencies – Environmental Matters" for additional information on environmental issues.) In 2001, these non-operating subsidiaries realized operating income of $31.4 million, primarily related to the $22.0 million benefit associated with the favorable appellate court decision regarding the RICO class action settlement, previously mentioned.

Liquidity

Cash flow from operations for the year ended December 31, 2003 increased $453.2 million, or 62%, compared to the same period last year. During 2003, KeySpan performed an analysis of costs capitalized for self-constructed property and inventory for income tax purposes. KeySpan filed a change of accounting method for income tax purposes resulting in a cumulative deduction for costs previously capitalized. As a result of this tax method change, along with accelerated deductions resulting from bonus depreciation, Keyspan received in October 2003, a $192.3 million refund from the Internal Revenue Service associated with the refund of prior year taxes, as well as an additional $85 million for tax payments made in 2002. On a comparative basis, tax refunds received in 2003 coupled with tax payments made in 2002, resulted in a cash flow benefit in 2003, compared to 2002, of approximately $310 million.

Comparative operating cash flow also reflects the collection of gas accounts receivable associated with higher winter gas heating sales. As a result of load additions, colder than normal winter weather during the first quarter, higher natural gas prices, and higher accounts receivable at the end of 2002, cash receipts from gas heating customers were higher in 2003 than in 2002. Further, the higher natural gas prices resulted in an increase in operating cash flow associated with the operations of Houston Exploration. These benefits to cash flow were partially offset by significantly higher cash expenditures to re-fill natural gas storage levels as a result of the higher natural gas prices.

Cash flow from operations decreased by $158.7 million, or 18%, in 2002 compared to 2001. Operating cash flow from gas exploration and production activities was adversely impacted by significantly lower realized gas prices in 2002. Further, cash flow from operations in 2002 reflects the funding of the pension obligations related to our New England subsidiaries of $80 million. These adverse effects on cash flow were partially offset by the termination of two interest rate swap agreements that resulted in a favorable operating cash flow benefit of approximately $23.4 million, as well as lower income tax payments. State and federal tax payments were lower in 2002, compared to 2001, as KeySpan was in a refund position with regard to such taxes. (See Note 8 to the Consolidated Financial Statements, "Hedging, Derivative Financial Instruments, and Fair Values" for an explanation of the interest rate hedges.)

At December 31, 2003, we had cash and temporary cash investments of $205.8 million. During 2003, we repaid $433.8 million of commercial paper and, at December 31, 2003, $481.9 million of commercial paper was outstanding at a weighted-average annualized interest rate of 1.2%. We had the ability to borrow up to an additional $818.1 million at December 31, 2003, under the terms of our credit facility.

In 2003, KeySpan renewed its $1.3 billion revolving credit facility, which was syndicated among sixteen banks. The facility is used to support KeySpan's commercial paper program, and consists of two separate credit facilities with different maturities but substantially similar terms and conditions: a $450 million facility that extends for 364 days, and a $850 million facility that is committed for three years. The fees for the facilities are subject to a ratings-based grid, with an annual fee that ranges from eight to twenty five basis points on the 364-day facility and ten to twenty basis points on the three-year facility. Both credit agreements allow for KeySpan to borrow using several different types of loans; specifically, Eurodollar loans, ABR loans, or competitively bid loans. Eurodollar loans are based on the Eurodollar rate plus a margin. ABR loans are based on the highest of the Prime Rate, the base CD rate plus 1%, or the Federal Funds Effective Rate plus 0.5%, plus a margin. Competitive bid loans are based on bid results requested by KeySpan from the lenders. The margins on both facilities are ratings based and range from zero basis points to 112.5 basis points. The margins are increased if outstanding loans are in excess of 33% of the total facility. In addition, the 364-day facility has a one-year term out option, which would cost an additional 0.25% if utilized. We do not anticipate borrowing against this facility; however, if the credit rating on our commercial paper program were to be downgraded, it may be necessary to do so.

The credit facility contains certain affirmative and negative operating covenants, including restrictions on KeySpan's ability to mortgage, pledge, encumber or otherwise subject its property to any lien, as well as certain financial covenants that require us to, among other things, maintain a consolidated indebtedness to consolidated capitalization ratio of no more than 64%. Violation of this covenant could result in the termination of the credit facility and the required repayment of amounts borrowed thereunder, as well as possible cross defaults under other debt agreements.

Under the terms of the credit facility, KeySpan's debt-to-total capitalization ratio reflects 80% equity treatment for the MEDS Equity Units issued in 2002. At December 31, 2003, consolidated indebtedness, as calculated under the terms of the credit facility was 58.2% of consolidated capitalization. The leasing arrangement associated with the Ravenswood facility ("Master Lease") has always been treated as debt for the calculation of debt-to-total capitalization under KeySpan's credit facility. Beginning on December 31, 2003, KeySpan was required to consolidate the Master Lease Agreement as required by FIN 46 and as a result the Master Lease Agreement is reflected as debt on the Consolidated Balance Sheet. See the discussion under "Off-Balance Sheet Arrangements" for an explanation of the Master Lease Agreement.

The credit facility also requires that net cash proceeds from the sale of significant subsidiaries be applied to reduce consolidated indebtedness. Further, an acceleration of indebtedness of KeySpan or one of its subsidiaries for borrowed money in excess of $25 million in the aggregate, if not annulled within 30 days after written notice, would create an event of default under the Indenture dated November 1, 2000, between KeySpan Corporation and the JPMorganChase Bank as Trustee. At December 31, 2003, KeySpan was in compliance with all covenants.

Houston Exploration has a revolving credit facility with a commercial banking syndicate that provides Houston Exploration with a commitment of $300 million, which can be increased at its option to a maximum of $350 million with prior approval from the banking syndicate. The credit facility is subject to borrowing base limitations, currently set at $300 million and is re-determined semi-annually. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The credit facility matures on July 15, 2005, is unsecured and, with the exception of trade payables, ranks senior to all existing debt of Houston Exploration.

Under the Houston Exploration credit facility, interest on base rate loans is payable at a fluctuating rate, or base rate, equal to the sum of (a) the greater of the federal funds rate plus 0.50% or the bank's prime rate plus (b) a variable margin between 0% and 0.50%, depending on the amount of borrowings outstanding under the credit facility. Interest on fixed rate loans is payable at a fixed rate equal to the sum of (a) a quoted reserve adjusted LIBOR rate, plus (b) a variable margin between 1.25% and 2.00%, depending on the amount of borrowings outstanding under the credit facility.

Financial covenants require Houston Exploration to, among other things, (i) maintain an interest coverage ratio of at least 3.00 to 1.00 of earnings before interest, taxes and depreciation ("EBITDA") to cash interest; (ii) maintain a total debt to EBITDA ratio of not more than 3.50 to 1.00; and (iii) generally prohibits the hedging of more than 70% of natural gas and oil production during any 12-month period. At December 31, 2003, Houston Exploration was in compliance with all financial covenants.

During 2003, Houston Exploration borrowed $239 million under its credit facility and repaid $264 million. At December 31, 2003, Houston Exploration had $127 million of borrowings outstanding under its credit facility at an average rate of 3.42%. In addition, $0.4 million was committed under outstanding letters of credit obligations and $172.6 million of borrowing capacity was available.

In 2003, KeySpan Canada replaced its two outstanding credit facilities with one new facility with three tranches that combined allowed KeySpan Canada to borrow up to approximately $125 million. At the time of the partial sale of KeySpan Canada, net proceeds from the sale of $119.4 million plus an additional $45.7 million drawn under the new credit facilities were used to pay down existing outstanding debt of $160.4 million. During the third quarter of 2003, KeySpan Canada issued Cdn$125 million, or approximately US$93 million, in long-term secured notes in a private placement. The proceeds of the offering were used to pay-down, in its entirety, outstanding borrowings under the credit facility. Further, one tranch of the credit facility was discontinued. (See "Capital Expenditures and Financing - Financing" below for further information regarding the long-term debt issuance.) At December 31, 2003, KeySpan Canada's credit facility had the following two tranches with the following maturities: (i) $37.5 million matures in 364 days: and (ii) $37.5 million matures in two years. During 2003, KeySpan Canada borrowed $71.5 million from its prior credit facilities and repaid $240.3 million. During the fourth quarter of 2003, KeySpan Canada borrowed $18.1 million under the new facility and at December 31, 2003, $56.9 million was available for future borrowing.

In 2003, the Boston Gas Company redeemed all 562,700 shares of its outstanding Variable Term Cumulative Preferred Stock, 6.42% Series A at its par value of $25 per share. The total payment was $14.3 million that included $0.2 million of accumulated dividends. This preferred stock series had been reflected as minority interest on KeySpan's Consolidated Balance Sheet.

On January 17, 2003, KeySpan sold 13.9 million shares of common stock on the open market and realized net proceeds of approximately $473 million. All shares were offered by KeySpan pursuant to the effective shelf registration statement filed with the SEC. Net proceeds from the equity sale were used to call $447 million of outstanding promissory notes to LIPA as is further explained in "Capital Expenditures and Financing" below. In addition, as previously noted, we used the net proceeds of approximately $79 million received in connection with the partial monetization of Houston Exploration to repay short-term debt.

A substantial portion of consolidated revenues are derived from the operations of businesses within the Electric Services segment, that are largely dependent upon two large customers – LIPA and the NYISO. Accordingly, our cash flows are dependent upon the timely payment of amounts owed to us by these customers.

We satisfy our seasonal working capital requirements primarily through internally generated funds and the issuance of commercial paper. We believe that these sources of funds are sufficient to meet our seasonal working capital needs.

Capital Expenditures and Financing

Construction Expenditures

The table below sets forth our construction expenditures by operating segment for the periods indicated:

	Year Ended December 31,	
(In Thousands of Dollars)	2003	2002
Gas Distribution	$ 419,549	$ 412,433
Electric Services	256,498	348,147
Energy Investments	314,097	272,720
Energy Services and other	21,572	27,722
	$1,011,716	$ 1,061,022

Construction expenditures related to the Gas Distribution segment are primarily for the renewal and replacement of mains and services and for the expansion of the gas distribution system. Construction expenditures for the Electric Services segment reflect costs to: (i) maintain our generating facilities; (ii) expand the Ravenswood facility; and (iii) construct new Long Island generating facilities as previously noted. The decrease in Electric Services construction expenditures in 2003, compared to last year reflects the fact that construction of the Glenwood and Port Jefferson peaking facilities was substantially completed by June 30, 2002. Construction expenditures related to the Energy Investments segment primarily reflect costs associated with gas exploration and production activities. These costs are related to the exploration and development of properties primarily in Southern Louisiana and in the Gulf of Mexico. Expenditures also include development costs associated with the joint venture with Houston Exploration, as well as costs related to KeySpan Canada's gas processing facilities.

Construction expenditures for 2004 are estimated to be approximately the same as 2003 at $1 billion. The amount of future construction expenditures is reviewed on an ongoing basis and can be affected by timing, scope and changes in investment opportunities.

Financing

In November 2003, KeySpan closed on a financing transaction pursuant to which $128 million tax-exempt bonds with a 5.25% coupon maturing in June 2027 were issued on its behalf. Fifty-three million dollars of these Industrial Development Revenue Bonds were issued through the Nassau County Industrial Development Authority for the construction of the Glenwood electric-generation peaking plant and the balance of $75 million was issued by the Suffolk County Industrial Development Authority for the Port Jefferson electric-generation peaking plant. Proceeds from the transaction were used to pay down commercial paper used for the construction, installation and equipping of the two facilities.

In 2003, KeySpan Canada, issued Cdn$125 million, or approximately US$93 million, long-term secured notes in a private placement to investors in Canada and the United States. The notes were issued in the following three series: (i) Cdn$20 million 5.42% senior secured notes due 2008; (ii) Cdn$52.5 million 5.79% senior secured notes due 2010; and (iii) Cdn$52.5 million

6.16% senior secured notes due 2013. The proceeds of the offering were used to repay KeySpan Canada's credit facility.

In addition, Houston Exploration closed on a private placement issue of $175 million 7.0%, senior subordinated notes due 2013. Interest payments began on December 15, 2003, and will be paid semi-annually thereafter. The notes will mature on June 15, 2013. Houston Exploration has the right to redeem the notes as of June 15, 2008, at a price equal to the issue price plus a specified redemption premium. Until June 15, 2006, Houston Exploration may also redeem up to 35% of the notes at a redemption price of 107% with proceeds from an equity offering. Houston Exploration incurred approximately $4.5 million of debt issuance costs on this private placement. Houston Exploration used a portion of the net proceeds from the issuance to redeem all of its outstanding $100 million principal amount of 8.625% senior subordinated notes due 2008 at a price of 104.313% of par plus interest accrued to the redemption date. Debt redemption costs totaled approximately $5.9 million. The remaining net proceeds from the offering were used to reduce debt amounts associated with Houston Exploration's bank revolving credit facility.

We also issued $300 million of medium-term and long-term debt in 2003. The debt was issued in the following two series: (i) $150 million 4.65% Notes due 2013; and (ii) $150 million 5.875% Notes due 2033. The proceeds of this issuance were used to pay down outstanding commercial paper.

In connection with the KeySpan/LILCO business combination, KeySpan and certain of its subsidiaries issued promissory notes to LIPA to support certain debt obligations assumed by LIPA. At December 31, 2002, the remaining principal amount of promissory notes issued to LIPA was approximately $600 million. Under these promissory notes, KeySpan is required to obtain letters of credit to secure its payment obligations if its long-term debt is not rated at least in the "A" range by at least two nationally recognized statistical rating agencies. In an effort to mitigate the dilutive effect of the equity issuance previously mentioned, in March 2003, we called approximately $447 million aggregate principal amount of such promissory notes at the applicable redemption prices plus accrued and unpaid interest through the dates of redemption. Interest savings associated with this redemption were $15.6 million after-tax, or $0.10 per share, in 2003.

In the fourth quarter of 2003, KeySpan received authorization from the SEC, under PUHCA, to issue up to an additional $3 billion of securities through December 31, 2006. This authorization provides KeySpan with the necessary flexibility to finance our future capital requirements over the next three years. See the discussion under the caption "Regulation and Rate Matters – Securities and Exchange Commission Regulation" for a further discussion of this approval.

We anticipate replacing outstanding commercial paper related to the construction of a new 250 MW combined cycle generating facility at the Ravenswood facility site with the proceeds from a proposed sale/leaseback transaction anticipated to be completed in the second quarter of 2004. (See Note 15 to the Consolidated Financial Statements "Subsequent Events" for further details on this proposed transaction). We will continue to evaluate our capital structure and financing strategy for 2004 and beyond. We believe that our current sources of funding (i.e., internally generated funds, the issuance of additional securities as noted above, and the availability of commercial paper) are sufficient to meet our anticipated capital needs for the foreseeable future.

The following table represents the ratings of our long-term debt at December 31, 2003. Currently, Standard & Poor's and Moody's Investor Services ratings on KeySpan's and its subsidiaries' long-term debt are on negative outlook.

	Moody's Investor Services	Standard & Poor's	FitchRatings
KeySpan Corporation	A3	A	A-
KEDNY	N/A	A+	A+
KEDLI	A2	A+	A-
Boston Gas	A2	A	N/A
Colonial Gas	A2	A+	N/A
Electric Generation	A3	A	N/A

Off-Balance Sheet Arrangements

Variable Interest Entity

We have an arrangement with a variable interest entity through which we lease a portion of the Ravenswood facility. We acquired the Ravenswood facility, in part, through the variable interest entity from Consolidated Edison on June 18, 1999 for approximately $597 million. In order to reduce the initial cash requirements, we entered into a lease agreement (the "Master Lease") with a variable interest unaffiliated financing entity that acquired a portion of the facility, three steam generating units, directly from Consolidated Edison and leased it to a KeySpan subsidiary. The variable interest unaffiliated financing entity acquired the property for $425 million, financed with debt of $412.3 million (97% of capitalization) and equity of $12.7 million (3% of capitalization). Monthly lease payments generally equal the monthly interest expense on the debt securities.

In December 2003, KeySpan implemented FIN 46 that required us to consolidate this variable interest entity and classify the Master Lease as $412.3 million long-term debt on the Consolidated Balance Sheet. Further, we recorded an asset on the Consolidated Balance Sheet for an amount substantially equal to the estimated fair market value of the leased assets at inception of the lease, less depreciation since that time. As previously mentioned, under the terms of our credit facility the Master Lease has been considered debt in the ratio of debt-to-total capitalization since the inception of the lease and therefore, implementation of FIN 46 had no impact on our credit facility. The Interpretation also requires us to continue to depreciate the leased assets over their remaining economic lives. (See Note 7 to the Consolidated Financial Statements, "Contractual Obligations, Financial Guarantees and Contingencies" for additional information regarding the leasing arrangement associated with the Master Lease Agreement and FIN 46 implementation issues.)

Guarantees

KeySpan had a number of financial guarantees for its subsidiaries at December 31, 2003. KeySpan has fully and unconditionally guaranteed: (i) $525 million of medium-term notes issued by KEDLI; (ii) the obligations of KeySpan Ravenswood LLC, the lessee under the $425 million

Master Lease Agreement associated with the Ravenswood facility; and (iii) the payment obligations of our subsidiaries related to $128 million of tax-exempt bonds issued through the Nassau County and Suffolk County Industrial Development Authority for the construction of the Glenwood and Port Jefferson electric-generation peaking facilities. The medium-term notes, the Master Lease Agreement and the tax-exempt bonds are reflected on the Consolidated Balance Sheet. Further, KeySpan has guaranteed: (i) up to $168 million of surety bonds associated with certain construction projects currently being performed by subsidiaries within the Energy Services segment; (ii) certain supply contracts, margin accounts and purchase orders for certain subsidiaries in an aggregate amount of $43 million; and (iii) $67 million of subsidiary letters of credit. The guarantee of the KEDLI medium-term notes expires in 2010, while the Master Lease Agreement can be extended to 2009. The guarantee of the payment obligations of our subsidiaries related to the tax-exempt financing extends to 2027. The other guarantees have terms that do not extend beyond 2005 and are not recorded on the Consolidated Balance Sheet. At this time, we have no reason to believe that our subsidiaries will default on their current obligations. However, we cannot predict when or if any defaults may take place or the impact such defaults may have on our consolidated results of operations, financial condition or cash flows. (See Note 7 to the Consolidated Financial Statements, "Contractual Obligations, Financial Guarantees and Contingencies" for additional information regarding KeySpan's guarantees.)

In addition, KeySpan intends to guarantee approximately $360 million in connection with a proposed sale/leaseback transaction for the financing of a new 250 MW electric generating facility located on the Ravenswood site. (See Note 15 to the Consolidated Financial Statements "Subsequent Events" for further details regarding this transaction.)

Contractual Obligations

KeySpan has certain contractual obligations related to its outstanding long-term debt, outstanding credit facility borrowings, outstanding commercial paper borrowings, operating and capital leases, and demand charges associated with certain commodity purchases. KeySpan's outstanding short-term and long-term debt issuances are explained in more detail in Note 6 to the Consolidated Financial Statements "Long-Term Debt." KeySpan's operating and capital leases, as well as its demand charges are more fully detailed in Note 7 to the Consolidated Financial Statements "Contractual Obligations, Financial Guarantees and Contingencies." The table below reflects maturity schedules for KeySpan's contractual obligations at December 31, 2003:

(In Thousands of Dollars)				
Contractual Obligations	Total	1 - 3 Years	4 - 5 Years	After 5 Years
Long-term Debt	$ 5,625,706	$1,814,999	$ 161,094	$ 3,649,613
Capital Leases	12,981	3,237	2,192	7,552
Operating Leases	417,124	179,316	115,597	122,211
Master Lease Payments	169,532	92,472	61,648	15,412
Interest Payments	3,387,891	910,937	458,547	2,018,407
Demand Charges	452,045	452,045	-	-
Total Contractual Cash Obligations	$ 10,065,279	$3,453,006	$ 799,078	$ 5,813,195
Commercial Paper	$ 481,900	Revolving		

Discussion of Critical Accounting Policies and Assumptions

In preparing our financial statements, the application of certain accounting policies requires difficult, subjective and/or complex judgments. The circumstances that make these judgments difficult, subjective and/or complex have to do with the need to make estimates about the impact of matters that are inherently uncertain. Actual effects on our financial position and results of operations may vary significantly from expected results if the judgments and assumptions underlying the estimates prove to be inaccurate. The critical accounting policies requiring such subjectivity are discussed below.

Percentage-of-Completion

Percentage-of-completion accounting is a method of accounting for long-term construction type contracts in accordance with Generally Accepted Accounting Principles and, accordingly, the method used for engineering and mechanical contracting revenue recognition by the Energy Services segment. Percentage-of-completion is measured principally by comparing the percentage of costs incurred to date for each contract to the estimated total costs for each contract at completion. Provisions for estimated losses on uncompleted contracts are made in the period in which such losses are known. Application of percentage-of-completion accounting, results in the recognition of costs and estimated earnings in excess of billings on uncompleted contracts (recorded within the Consolidated Balance Sheet) which arise when revenues have been recognized but the amounts cannot be billed under the terms of the contracts. Such amounts are recoverable from customers based on various measures of performance, including achievement of certain milestones, completion of specified units or completion of the contract. Due to uncertainties inherent within estimates employed to apply percentage-of-completion accounting, it is possible that estimates will be revised as project work progresses. Changes in estimates resulting in additional future costs to complete projects can result in reduced margins or loss contracts. Unapproved change orders and claims also involve the use of estimates, and it is reasonably possible that revisions to the estimated recoverable amounts of recorded change orders and claims may be made in the near-term. Application of percentage-of-completion accounting requires that the impact of those revised estimates be reported in the consolidated financial statements prospectively.

Valuation of Goodwill

KeySpan records goodwill on purchase transactions, representing the excess of acquisition cost over the fair value of net assets acquired. In testing for goodwill impairment under Statement of Financial Accounting Standards ("SFAS") 142 "Goodwill and Other Intangible Assets", significant reliance is placed upon a number of estimates regarding future performance that require broad assumptions and significant judgment by management. A change in the fair value of our investments could cause a significant change in the carrying value of goodwill. The assumptions used to measure the fair value of our investments are the same as those used by us to prepare yearly operating segment and consolidated earnings and cash flow forecasts. In addition, these assumptions are used to set yearly budgetary guidelines.

KeySpan currently has $1.8 billion of recorded goodwill, the majority of which is recorded in the Gas Distribution and Energy Investments segment, with approximately $171 million recorded in the Energy Services segment. As permitted under SFAS 142, we can rely on our previous valuations for the annual impairment testing provided that the following criteria for each reporting unit are met: (a) the assets and liabilities that make up the reporting unit have not changed significantly since the most recent fair value determination; and (b) the most recent fair value determination resulted in an amount that exceeded the carrying amount of the reporting unit by a substantial margin and there is no economic indication that the carrying value of goodwill may be impaired. In the case of the Gas Distribution and the Energy Investments segments, the above criteria have been met and therefore, there was no impairment to goodwill in 2003. In regard to the Energy Services segment, adverse economic conditions experienced in the construction industry in the Northeastern United States during 2003 and its related impact on the operating results of this segment, prompted management to conduct an impairment test during the fourth quarter.

KeySpan employed a combination of two methodologies in determining the fair value for its investment in the Energy Services segment, a market valuation approach and an income valuation approach. A third party specialist was engaged to assist with the valuation and evaluate the reasonableness of key assumptions employed.

Since the companies included in the Energy Services segment are not publicly traded, the market valuation approach was used to estimate their total enterprise value or aggregate potential market value. Under the market valuation approach, KeySpan compared relevant financial information relating to the companies included in the Energy Services segment to the corresponding financial information for a peer group of companies in the specialty trade-contracting sector of the construction industry. The market valuation approach derived enterprise value to earnings before interest and taxes ("EV/EBIT") multiples and enterprise value to earnings before interest, taxes, depreciation and amortization ("EV/EBITDA") multiples. Though there are numerous multiples that can be used to value an individual firm, these multiples were selected since they offer the closest parallels to discounted cash flow valuation and are most appropriate for the Energy Services segment's market sector.

In addition to the market valuation approach, we also used an income valuation approach or discounted cash flow ("DCF") valuation approach to estimate the fair market value for the companies included in the Energy Services segment. Under the income valuation approach, the fair value of a firm is obtained by discounting the sum of (i) the expected future cash flows to a firm; and (ii) the terminal value of a firm. The discount factor used in the calculation is basically a firm's weighted-average cost of capital. KeySpan was required to make certain significant assumptions in the income approach, specifically the weighted-average cost of capital, short and long-term growth rates and expected future cash flows. The cash flow model is based on relevant industry forecasts projecting improved market conditions over the next five years, continued increases in business activity that are likely to result in backlog growth, and short and long-term revenue and operating margin growth projections that management believes are reasonable given historical performance.

As a result of our valuation, management has determined that the fair value of the assets adequately exceeds their carrying value and no impairment charge is necessary. Management will continue to review and focus on our overall strategy for this business unit and accordingly will continue to evaluate the related carrying value of the goodwill. While we believe that our assumptions are reasonable, actual results, however, may differ from our projections.

Accounting for the Effects of Rate Regulation on Gas Distribution Operations

The financial statements of the Gas Distribution segment reflect the ratemaking policies and orders of the New York Public Service Commission ("NYPSC"), the New Hampshire Public Utilities Commission ("NHPUC"), and the Massachusetts Department of Telecommunications and Energy ("DTE").

Four of our six regulated gas utilities (KEDNY, KEDLI, Boston Gas Company and EnergyNorth Natural Gas, Inc.) are subject to the provisions of SFAS 71, "Accounting for the Effects of Certain Types of Regulation." This statement recognizes the actions of regulators, through the ratemaking process, to create future economic benefits and obligations affecting rate-regulated companies.

In separate merger-related orders issued by the DTE, the base rates charged by Colonial Gas Company and Essex Gas Company have been frozen at their current levels for ten-year periods ending 2009 and 2008, respectively. Due to the length of these base rate freezes, the Colonial and Essex Gas Companies had previously discontinued the application of SFAS 71.

SFAS 71 allows for the deferral of expenses and income on the consolidated balance sheet as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate setting process in a period different from the period in which they would have been reflected in the consolidated statements of income of an unregulated company. These deferred regulatory assets and liabilities are then recognized in the consolidated statement of income in the period in which the amounts are reflected in rates.

Rate regulation is undergoing significant change as regulators and customers seek lower prices for utility service and greater competition among energy service providers. In the event that regulation significantly changes the opportunity for us to recover costs in the future, all or a portion of our regulated operations may no longer meet the criteria for the application of SFAS 71. In that event, a write-down of our existing regulatory assets and liabilities could result. If we were unable to continue to apply the provisions of SFAS 71 for any of our rate regulated subsidiaries, we would apply the provisions of SFAS 101 "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71." We estimate that the write-off of our net regulatory assets at December 31, 2003 could result in a charge to net income of approximately $300 million or $1.89 per share, which would be classified as an extraordinary item. In management's opinion, our regulated subsidiaries that currently are subject to the provisions of SFAS 71 will continue to be subject to SFAS 71 for the foreseeable future.

As is further discussed under the caption "Regulation and Rate Matters," in October 2003 the DTE rendered its decision on the Boston Gas Company's base rate case and Performance Based Rate Plan proposal submitted to the DTE in April 2003. The DTE approved a $27 million increase in base revenues, as well as an allowed rate of return on equity of 10.2%. The DTE also approved a Performance Based Rate Plan for up to ten years. The rate plans previously in effect for KEDNY and KEDLI have expired. The continued application of SFAS 71 to record the activities of these subsidiaries is contingent upon the actions of regulators with regard to future rate plans. We are currently evaluating various options that may be available to us including, but not limited to, proposing new plans for KEDNY and KEDLI. The ultimate resolution of any future rate plans could have a significant impact on the application of SFAS 71 to these entities and, accordingly, on our financial position, results of operations and cash flows. However, management believes that currently available facts support the continued application of SFAS 71 and that all regulatory assets and liabilities are recoverable or refundable through the regulatory environment.

Pension and Other Postretirement Benefits

As discussed in Note 4 to the Consolidated Financial Statements, "Postretirement Benefits," KeySpan participates in both non-contributory defined benefit pension plans, as well as other post-retirement benefit ("OPEB") plans (collectively "postretirement plans"). KeySpan's reported costs of providing pension and OPEB benefits are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension and OPEB costs (collectively "postretirement costs") are impacted by actual employee demographics, the level of contributions made to the plans, earnings on plan assets, and health care cost trends. Changes made to the provisions of these plans may also impact current and future postretirement costs. Postretirement costs may also be significantly affected by changes in key actuarial assumptions, including, anticipated rates of return on plan assets and the discount rates used in determining the postretirement costs and benefit obligations. Actual results that differ from our assumptions are accumulated and amortized over ten years.

Certain gas distribution subsidiaries are subject to SFAS 71, and, as a result, changes in postretirement expenses are deferred for future recovery from or refund to gas sales customers. (However, KEDNY, although subject to SFAS 71, does not have a recovery mechanism in place for increases in postretirement costs.) Further, changes in postretirement expenses associated with subsidiaries that service the LIPA Agreements are also deferred for future recovery from or refund to LIPA.

For 2003, the assumed long-term rate of return on our postretirement plans' assets was 8.5% (pre-tax), net of expenses. This is an appropriate long-term expected rate of return on assets based on KeySpan's investment strategy, asset allocation and the historical outperformance of equity investments over long periods of time. The actual 10 year compound annual rate of return for the KeySpan Plans is greater than 8.5%.

KeySpan's master trust investment allocation policy target is 70% equity and 30% fixed income. At December 31, 2003, the actual investment allocation was 67% equities, 33% fixed income and cash. In an effort to maximize plan performance, actual asset allocation will fluctuate from year to year depending on the then current economic environment.

During 2003, KeySpan conducted an asset & liability study projecting asset returns and expected benefit payments over a 10-year period. Based on the results, KeySpan has developed a multiyear funding strategy for its postretirement plans. KeySpan believes that it is reasonable to assume assets can achieve or outperform the assumed long-term rate of return with the target allocation as a result of historical outperformance of equity investments over long-term periods.

A 25 basis point increase or decrease in the assumed long-term rate of return on plan assets would have impacted 2003 expense by approximately $4 million, before deferrals.

The year-end December 31, 2003 assumed discount rate used to determine postretirement obligations was 6.25%. Our discount rate assumption is based upon the current investment yield associated with rating agency indices that have high quality long-term corporate bonds. A 25 basis point increase or decrease in the assumed year-end discount rate would have had no impact on 2003 expense. However, a 25 basis point decrease in the assumed year-end discount rate would result in the recording of an additional minimum pension liability. A year-end discount rate of 6.00% would have required an additional $11 million debit to other comprehensive income ("OCI"), net of tax and deferrals.

At January 1, 2003, the assumed discount rate used to determine postretirement obligations was 6.75%. A 25 basis point increase or decrease in the assumed discount rate at the beginning of the year would have impacted 2003 expense by approximately $14 million, before deferrals.

Our health care cost trend assumptions are developed based on historical cost data, the near-term outlook and an assessment of likely long-term trends. The salary growth assumptions reflect our long-term outlook.

Historically, we have funded our qualified pension plans in excess of the amount required to satisfy minimum ERISA funding requirements. At December 31, 2003, we had a funding credit balance in excess of the ERISA minimum funding requirements and as a result KeySpan was not required to make any contributions to its qualified pension plans in 2003. However, although we have presently exceeded ERISA funding requirements, our pension plans, on an actuarial basis, are currently underfunded. Therefore, during 2003 KeySpan contributed $137 million to its postretirement plans.

For 2004, KeySpan expects to contribute a total of $147 million to its funded and unfunded post-retirement plans. Future funding requirements are heavily dependent on actual return on plan assets and prevailing interest rates.

Full Cost Accounting

Our gas exploration and production subsidiaries use the full cost method to account for their natural gas and oil properties. Under full cost accounting, all costs incurred in the acquisition, exploration, and development of natural gas and oil reserves are capitalized into a "full cost pool." Capitalized costs include costs of all unproved properties, internal costs directly related to natural gas and oil activities, and capitalized interest.

Under full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10%, plus the lower of cost or fair value of unproved properties less income tax effects (the "ceiling limitation"). A quarterly ceiling test is performed to evaluate whether the net book value of the full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion and amortization) less deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders' equity in the period of occurrence and typically results in lower depreciation, depletion and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date, held constant over the life of the reserves. Our gas exploration and production subsidiaries use derivative financial instruments that qualify for hedge accounting under SFAS 133 “Accounting for Derivative Instruments and Hedging Activities” to hedge against the volatility of natural gas prices. In accordance with current SEC guidelines, these derivatives are included in the estimated future cash flows in the ceiling test calculation. In calculating the ceiling test at December 31, 2003, our subsidiaries estimated that a full cost ceiling "cushion" existed, whereby the carrying value of the full cost pool was less that the ceiling limitation. No write-down is required when a cushion exists. Natural gas prices continue to be volatile and the risk that a write-down to the full cost pool will be required increases when natural gas prices are depressed or if there are significant downward revisions in estimated proved reserves.

Natural gas and oil reserve quantities represent estimates only. Under full cost accounting, reserve estimates are used to determine the full cost ceiling limitation, as well as the depletion rate. Houston Exploration estimates its proved reserves and future net revenues using sales prices estimated to be in effect as of the date it makes the reserve estimates. Natural gas prices, which have fluctuated widely in recent years, affect estimated quantities of proved reserves and future net revenues. Any estimates of natural gas and oil reserves and their values are inherently uncertain, including many factors beyond our control. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based upon actual production, results of future development and exploration activities, prevailing natural gas and oil prices, operating costs and other factors, which revision may be material. Reserve estimates are highly dependent upon the accuracy of the underlying assumptions. Actual future production may be materially different from estimated reserve quantities and the differences could materially affect future amortization of natural gas and oil properties.

Valuation of Derivative Instruments

We employ derivative instruments to manage commodity and financial market risk. All of our derivative instruments, except for certain weather derivatives, are reported on the Consolidated Balance Sheet at fair value in accordance with SFAS 133; weather derivatives are accounted for in accordance with Emerging Issues Task Force ("EITF") 99-2. None of KeySpan's derivative instruments qualify as "energy trading contracts" as defined by current accounting literature.

For those derivative instruments designated as cash flow hedges under SFAS 133, which are the majority of KeySpan's derivative instruments, changes in the market value are recorded in other comprehensive income on the Consolidated Balance Sheet, (in line with effectiveness measurements) and are recorded through earnings at the time of settlement. Hedge effectiveness is dependent upon various factors such as the use of hedge contracts with market points that are different from the underlying transaction, and to the extent hedge contracts are deemed ineffective, that portion will impact earnings.

Additionally, we use derivative financial instruments to reduce cash flow variability associated with the purchase price for a portion of future natural gas purchases for our regulated gas distribution activities; the accounting for such derivative instruments is subject to SFAS 71. Changes in the market value of these derivative instruments are recorded as regulatory assets and liabilities, as appropriate, on the Consolidated Balance Sheet. KeySpan's non-regulated subsidiaries employ a limited number of financial derivatives that do not qualify for hedge accounting treatment under SFAS 133, and, therefore, changes in the market value of these derivative instruments are recorded through earnings.

When available, quoted market prices are used to record a derivative contract's fair value. However market values for certain derivative contracts may not be readily available or determinable. If no active market exists for a commodity, a specific contract type, or for the entire term of a contract's duration, fair values are based on pricing models. Such models employ matrix pricing based on contracts with similar terms and risks, including pricing based on broker quotes and industry publications. KeySpan validates its internally developed fair values by using forecasted market information and mathematical extrapolation techniques. In addition, for hedges of forecasted transactions, KeySpan estimates the expected future cash flows of the forecasted transactions, as well as evaluates the probability of occurrence and timing of such transactions. Changes in market conditions or the occurrence of unforeseen events could affect the timing of recognition of changes in fair value of certain hedging derivatives.

See Note 8 to the Consolidated Financial Statements "Hedging, Derivative Financial Instruments and Fair Values" and Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" for a further description of all our derivative instruments.

Dividends

We are currently paying a dividend at an annual rate of $1.78 per common share. Our dividend policy is reviewed annually by the Board of Directors. The amount and timing of all dividend payments is subject to the discretion of the Board of Directors and will depend upon business conditions, results of operations, financial conditions and other factors. Based on currently foreseeable market conditions, we intend to maintain the annual dividend at the $1.78 level.

Pursuant to NYPSC orders, the ability of KEDNY and KEDLI to pay dividends to KeySpan is conditioned upon maintenance of a utility capital structure with debt not exceeding 55% and 58%, respectively, of total utility capitalization. In addition, the level of dividends paid by both utilities may not be increased from current levels if a 40 basis point penalty is incurred under the customer service performance program. At the end of KEDNY's and KEDLI's most recent rate years (September 30, 2003 and November 30, 2003, respectively), the ratio of debt to total utility capitalization was 41% and 49%, respectively. Additionally, we have met the requisite customer service performance standards. Our corporate and financial activities and those of each of our subsidiaries (including their ability to pay dividends to us) are also subject to regulation by the SEC. (For additional information, see the discussion under the heading "Regulation and Rate Matters - Securities and Exchange Commission Regulation").

Regulation and Rate Matters

Gas Distribution

By orders dated February 5, 1998 and April 14, 1998, the NYPSC approved the KeySpan/LILCO business combination and established gas rates for both KEDNY and KEDLI. Pursuant to the orders, $1 billion of efficiency savings, excluding gas costs, attributable to operating synergies that are expected to be realized over the ten-year period following the combination, were allocated to customers, net of transaction costs.

Effective May 29, 1998, KEDNY's base rates to core customers were reduced by $23.9 million annually. In addition, KEDNY is subject to an earnings sharing provision pursuant to which it is required to credit core customers with 60% of any utility earnings up to 100 basis points above certain threshold return on equity levels over the term of the rate plan (other than any earnings associated with discrete incentives) and 50% of any utility earnings in excess of 100 basis points above such threshold level. The threshold level for the rate year ended September 30, 2003 was 13.25%. KEDNY did not earn above its threshold return level in its rate year ended September 30, 2003. On September 30, 2002, KEDNY's rate agreement with the NYPSC expired. Under the terms of the agreement, the then current gas distribution rates and all other provisions, including the earnings sharing provision (at the 13.25% threshold level), remain in effect until changed by the NYPSC. At this time, we are currently evaluating various options that may be available to us regarding KEDNY's rates, including but not limited to, proposing a new rate plan.

The 1998 orders also required KEDLI to reduce base rates to its customers by $12.2 million annually effective February 5, 1998 and by an additional $6.3 million annually effective May 29, 1998. KEDLI is subject to an earnings sharing provision pursuant to which it is required to credit to firm customers 60% of any utility earnings in any rate year up to 100 basis points above a return on equity of 11.10% and 50% of any utility earnings in excess of a return on equity of 12.10%. KEDLI did not earn above its threshold return level in its rate year ended November 30, 2003. On November 30, 2000, KEDLI's rate agreement with the NYPSC expired. Under the terms of the agreement, the gas distribution rates and all other provisions, including the earnings sharing provision, will remain in effect until changed by the NYPSC. At this time, we are currently evaluating various options that may be available to us regarding KEDLI's rate plan, including but not limited to, proposing a new rate plan.

Boston Gas Company, Colonial Gas Company and Essex Gas Company operations are subject to Massachusetts's statutes applicable to gas utilities. Rates for gas sales and transportation service, distribution safety practices, issuance of securities and affiliate transactions are regulated by the DTE.

Regarding the Boston Gas Company, we filed a base rate case and Performance Based Rate Plan on April 16, 2003, to be effective in the fourth quarter of 2003. On October 31, 2003, the DTE rendered its decision on the Boston Gas Company's proposal and approved a $25.9 million increase in base revenues with an allowed return on equity of 10.2% assuming an equal balance of debt and equity. On January 27, 2004 the DTE issued orders on Boston Gas Company's Motions for Recalculation, Reconsideration and Clarification that granted an additional $1.1 million in base revenues, for a total of $27 million. The DTE also approved a true-up mechanism for pension and other postretirement benefit costs under which variations between actual pension and other postretirement benefit costs and amounts used to establish rates are deferred and collected from or refunded to customers in subsequent periods through an adjustment clause. This true-up mechanism allows for carrying charges on deferred assets and liabilities at Boston Gas Company's weighted-average cost of capital.

The DTE also approved a Performance Based Rate Plan (the "Plan") for up to ten years. The Plan allows for an annual revenue adjustment based on inflation, less a 0.41 percent productivity factor. Further, the plan contained a margin sharing mechanism, whereby 25% of earnings in excess of a 15% return on equity will be passed back to customers. Similarly, ratepayers would absorb 25% of any shortfall below a 7% return on equity.

Prior to the change in base rates and the new Plan noted above, Boston Gas Company's gas rates for local distribution service were governed by a five-year Performance-Based Rate Plan approved by the DTE in 1996 (the "Plan"). Under this Plan, Boston Gas Company's rates for local distribution were recalculated annually to reflect inflation for the previous 12 months, and reduced by a productivity factor of 1%. The productivity factor had been the subject of a remand proceeding at the DTE. With respect to this appeal, on March 7, 2002, the Massachusetts Supreme Judicial Court ruled in favor of Boston Gas Company and reduced the productivity factor from 1.0% to .5%.

In connection with the Eastern Enterprises acquisition of Colonial Gas Company in 1999, the DTE approved a merger and rate plan that resulted in a ten year freeze of base rates to Colonial Gas Company's firm customers. The base rate freeze is subject only to certain exogenous factors, such as changes in tax laws, accounting changes, or regulatory, judicial, or legislative changes. The Office of the Attorney General appealed the DTE's order to the Supreme Judicial Court, which appeal is still pending. Due to the length of the base rate freeze, Colonial Gas Company discontinued its application of SFAS 71. Essex Gas Company is also under a ten-year base rate freeze and has also discontinued its application of SFAS 71.

EnergyNorth Natural Gas, Inc.'s base rates continue as set by the NHPUC in 1993.

Electric Rate Matters

KeySpan sells to LIPA all of the capacity and, to the extent requested, energy conversion services from our existing Long Island based oil and gas-fired generating plants. Sales of capacity and energy conversion services are made under rates approved by the FERC in accordance with the Power Supply Agreement ("PSA") entered into between KeySpan and LIPA in 1998. The current FERC approved rates, which have been in effect since May 1998, expired on December 31, 2003. KeySpan filed with the FERC an updated cost of service for the Long Island based oil and gas-fired generating plants in October 2003. The rate filing included, among other things, an annual revenue increase of 2.1% or approximately $6.4 million, a return on equity of 11%, updated operating and maintenance expense levels and recovery of certain other costs. FERC approved implementation of new rates starting January 1, 2004, subject to refund. Settlement negotiations are currently ongoing.

Securities and Exchange Commission Regulation

KeySpan and its subsidiaries are subject to the jurisdiction of the SEC under PUHCA. The rules and regulations under PUHCA generally limit the operations of a registered holding company to a single integrated public utility system, plus additional energy-related businesses. In addition, the principal regulatory provisions of PUHCA: (i) regulate certain transactions among affiliates within a holding company system including the payment of dividends by such subsidiaries to a holding company; (ii) govern the issuance, acquisition and disposition of securities and assets by a holding company and its subsidiaries; (iii) limit the entry by registered holding companies and their subsidiaries into businesses other than electric and/or gas utility businesses; and (iv) require SEC approval for certain utility mergers and acquisitions.

The SEC's order issued on December 18, 2003, provides us with, among other things, authorization to do the following through December 31, 2006 (the "Authorization Period"): (a) to issue and sell up to an additional amount of $3.0 billion of common stock, preferred stock, preferred and equity-linked securities, and long-term debt securities (the "Long-Term Financing Limit") in accordance with certain defined parameters; (b) in addition to the Long-Term Financing Limit, to issue and sell up to an aggregate amount of $1.3 billion of short-term debt (the "Short-Term Financing Limit"); (c) to issue up to 13 million shares of common stock under dividend reinvestment and stock-based management incentive and employee benefit plans; (d) to maintain existing and enter into additional hedging transactions with respect to outstanding indebtedness in order to manage and minimize interest rate costs; (e) to issue guarantees and other forms of credit support in an aggregate principal amount not to exceed $4.0 billion outstanding at any one time; (f) to refund, repurchase (through open market purchases, tender offers or private transactions), replace or refinance debt or equity securities outstanding during the Authorization Period through the issuance of similar or any other type of authorized securities; (g) to pay dividends out of capital and unearned surplus as well as paid-in-capital with respect to certain subsidiaries, subject to certain limitations; (h) to engage in preliminary development activities and administrative and management activities in connection with anticipated investments in exempt wholesale generators, foreign utility companies and other energy-related companies; (i) to organize and/or acquire the equity securities of entities that will serve the purpose of facilitating authorized financings; (j) to invest up to $3.0 billion in exempt wholesale generators and foreign utility companies; (k) to create and/or acquire the securities of entities organized for the purpose of facilitating investments in other non-utility subsidiaries; and (l) to enter into certain types of affiliate transactions between certain non-utility subsidiaries involving cost structures above the typical "at-cost" limit.

In addition, we have committed that during the Authorization Period, our common equity will be at least 30% of our consolidated capitalization and each of our utility subsidiaries' common equity will be at least 30% of such entity's capitalization. As of December 31, 2003 our consolidated common equity was 38% of our consolidated capitalization, including commercial paper, and each of our utility subsidiaries common equity was at least 35% of its respective capitalization.

Electric Services - Revenue Mechanisms

LIPA Agreements

KeySpan, through certain of its subsidiaries, provides services to LIPA under the following agreements:

Management Services Agreement (“MSA”)

KeySpan manages the day-to-day operations, maintenance and capital improvements of the transmission and distribution (“T&D”) system. LIPA exercises control over the performance of the T&D system through specific standards for performance and incentives. In exchange for providing the services, we earn a $10 million annual management fee and are operating under a contract, which provides certain incentives and imposes certain penalties based upon performance. We have reached an agreement with LIPA to extend the MSA for 31 months through 2008, as discussed under the heading “Generation Purchase Right Agreement” below. Annual service incentives or penalties exist under the MSA if certain targets are achieved or not achieved. In addition, we can earn certain incentives for budget underruns associated with the day-to-day operations, maintenance and capital improvements of LIPA's T&D system. These incentives provide for us to (i) retain 100% on the first $5 million in annual budget underruns, and (ii) retain 50% of additional annual underruns up to 15% of the total cost budget, thereafter all savings accrue to LIPA. With respect to cost overruns, we will absorb the first $15 million of overruns, with a sharing of overruns above $15 million. There are certain limitations on the amount of cost sharing of overruns. To date, we have performed our obligations under the MSA within the agreed upon budget guidelines and we are committed to providing on-going services to LIPA within the established cost structure. However, no assurances can be given as to future operating results under this agreement.

Power Supply Agreement (“PSA”)

KeySpan sells to LIPA all of the capacity and, to the extent requested, energy conversion services from our existing Long Island based oil and gas-fired generating plants. Sales of capacity and energy conversion services are made under rates approved by the FERC. As noted previously, rates under the PSA have been reestablished for the contract year commencing January 1, 2004. Rates charged to LIPA include a fixed and variable component. The variable component is billed to LIPA on a monthly per megawatt hour basis and is dependent on the number of megawatt hours dispatched. LIPA has no obligation to purchase energy conversion services from us and is able to purchase energy or energy conversion services on a least-cost basis from all available sources consistent with existing interconnection limitations of the T&D system. The PSA provides incentives and penalties that can total $4 million annually for the maintenance of the output capability and the efficiency of the generating facilities. The PSA runs for a term of fifteen years through May 2013, with LIPA having the option to renew the PSA for an additional fifteen year term.

Energy Management Agreement ("EMA")

The EMA provides for KeySpan to procure and manage fuel supplies on behalf of LIPA to fuel the generating facilities under contract to it and perform off-system capacity and energy purchases on a least-cost basis to meet LIPA's needs. In exchange for these services we earn an annual fee of $1.5 million. In addition, we arrange for off-system sales on behalf of LIPA of excess output from the generating facilities and other power supplies either owned or under contract to LIPA. LIPA is entitled to two-thirds of the profit from any off-system energy sales. In addition, the EMA provides incentives and penalties that can total $7 million annually for performance related to fuel purchases and off-system power purchases. The EMA is expected to be in effect through 2013 for the procurement of fuel supplies and through 2006 for off-system management services.

Under these agreements, we are required to obtain a letter of credit in the aggregate amount of $60 million supporting our obligations to provide the various services if our long-term debt is not rated in the "A" range by a nationally recognized rating agency.

Generation Purchase Right Agreement ("GPRA")

Under the GPRA, LIPA originally had the right for a one-year period beginning on May 28, 2001, to acquire all of our Long Island based generating assets formerly owned by LILCO at fair market value at the time of the exercise of such right.

By agreement dated March 29, 2002, LIPA and KeySpan amended the GPRA to provide for a new six month option period ending on May 28, 2005. The other terms of the option reflected in the GPRA remained unchanged. In return for providing LIPA an extension of the GPRA, KeySpan has been provided with a corresponding extension of 31 months for the MSA to the end of 2008.

The extension is the result of an initiative established by LIPA to work with KeySpan and others to review Long Island's long-term energy needs. LIPA and KeySpan will jointly analyze new energy supply options including re-powering existing plants, renewable energy technologies, distributed generation, conservation initiatives and retail competition. The extension allows both LIPA and KeySpan to explore alternatives to the GPRA including re-powering existing facilities, the sale of some or all of KeySpan's plants to LIPA, or the sale of some or all of these plants to other investor-owned entities.

KeySpan Glenwood and Port Jefferson Energy Centers

KeySpan Glenwood Energy Center LLC and KeySpan Port Jefferson Energy Center LLC have entered into 25 year Power Purchase Agreements (the "PPAs") with LIPA. Under the terms of the PPAs, these subsidiaries sell capacity, energy conversion services and ancillary services to LIPA. Both plants are designed to produce 79.9 megawatts. Under the PPAs, LIPA pays a monthly capacity fee, which guarantees full recovery of each plant's construction costs, as well as an appropriate rate of return on investment. The PPAs also obligate LIPA to pay for each plant's costs of operation and maintenance. These costs are billed on a monthly estimated basis and are subject to true-up for actual costs incurred.

Ravenswood Facility

We currently sell capacity, energy and ancillary services associated with the Ravenswood facility through a bidding process into the NYISO energy markets on both a day-ahead and a real-time basis. We also have the ability to enter into bilateral transactions to sell all or a portion of the energy produced by the Ravenswood facility to load serving entities, i.e. entities that sell to end-users or to brokers and marketers.

Environmental Matters

KeySpan is subject to various federal, state and local laws and regulatory programs related to the environment. During 2003, we undertook an extensive review of all our current and former properties that are or may be subject to environmental cleanup activities. As a result of this study, we adjusted reserve balances for estimated manufactured gas plant ("MGP") related environmental cleanup activities, as well as estimated environmental cleanup costs related to three non-utility sites. Through various rate orders issued by the NYPSC, DTE and NHPUC, costs related to MGP environmental cleanup activities are recovered in rates charged to gas distribution customers and, as a result, adjustments to these reserve balances do not impact earnings. However, environmental cleanup activities related to the three non-utility sites are not subject to rate recovery. Based on the recently concluded environmental study we reduced our reserve balance for future cleanup costs related to these sites and realized a pre-tax operating income benefit of $10 million.

We estimate that the remaining cost of our MGP related environmental cleanup activities, including costs associated with the Ravenswood facility, will be approximately $269.1 million and we have recorded a related liability for such amount. We have also recorded an additional $25.6 million liability, representing the estimated environmental cleanup costs related to a former coal tar processing facility. As of December 31, 2003, we have expended a total of $101.1 million on environmental investigation and remediation activities. (See Note 7 to the Consolidated Financial Statements, "Contractual Obligations, Guarantees and Contingencies" for a further explanation of these matters.)

Market and Credit Risk Management Activities

Market Risk: KeySpan is exposed to market risk arising from potential changes in one or more market variables, such as energy commodity price risk, interest rate risk, foreign currency exchange rate risk, volumetric risk due to weather or other variables. Such risk includes any or all changes in value whether caused by commodity positions, asset ownership, business or contractual obligations, debt covenants, exposure concentration, currency, weather, and other factors regardless of accounting method. We manage our exposure to changes in market prices using various risk management techniques for non-trading purposes, including hedging through the use of derivative instruments, both exchange-traded and over-the-counter contracts, purchase of insurance and execution of other contractual arrangements.

Credit Risk: KeySpan is exposed to credit risk arising from the potential that our counterparties fail to perform on their contractual obligations. Our credit exposures are created primarily through the sale of gas and transportation services to residential, commercial, electric generation, and industrial customers and the provision of retail access services to gas marketers, by our regulated gas businesses; the sale of commodities and services to LIPA and the NYISO; the sale of gas, power and services to our retail customers by our unregulated energy service businesses; entering into financial and energy derivative contracts with energy marketing companies and financial institutions; and the sale of gas, natural gas liquids, oil and processing services to energy marketing and oil and gas production companies.

We have regional concentration of credit risk due to receivables from residential, commercial and industrial customers in New York, New Hampshire and Massachusetts, although this credit risk is spread over a diversified base of residential, commercial and industrial customers. Customers' payment records are monitored and action is taken, when appropriate. Companies within the Energy Services segment have a concentration of credit risk to large customers and to the governmental and healthcare industries.

We also have concentrations of credit risk from LIPA, our largest customer, and from other energy companies. Concentration of energy company counterparties may impact overall exposure to credit risk in that our counterparties may be similarly impacted by changes in economic, regulatory or other considerations. We actively monitor the credit profile of our wholesale counterparties in derivative and other contractual arrangements, and manage our level of exposure accordingly. Over the past year, the credit quality of certain energy companies has declined. In instances where counterparties' credit quality has declined, we may limit our credit exposure by restricting new transactions with the counterparty, requiring additional collateral or credit support and negotiating the early termination of certain agreements.

Equity and Debt Securities Risk: KeySpan is exposed to price risk due to investments in equity and debt securities held to fund benefit payments for various employee pension and other postretirement benefit plans. To the extent that the values of investments held decline, the effect will be reflected in KeySpan's recognition of periodic cost of such employee benefit plans and the determination of the amount of cash to be contributed to the employee benefit plans.

Regulatory Issues and Competitive Environment

We are subject to various other risk exposures and uncertainties associated with our gas and electric operations. The most significant contingency involves the evolution of the gas distribution and electric industries towards more competitive and deregulated environments. Set forth below is a description of these exposures.

The Gas Industry

Long Island and New York

The NYPSC continues to conduct collaborative proceedings on ways to develop the competitive energy market in New York. On July 13, 2001, the presiding officers in the case issued their recommended decision ("RD"). The RD recommends that the NYPSC adopt an end state vision that includes removing the utilities from the provision of the energy (gas and electric) commodity. The RD also recommends that utilities exit the commodity function only where there is a workably competitive market. The RD states that the only market that is currently workably competitive is the commodity market for non-residential large- use gas customers. Parties filed briefs on and opposing exceptions to the RD. On January 27, 2004, the NYPSC issued a notice seeking further comments on the matters addressed in the RD, in light of the current state of the retail market and the experience of the past few years.

On May 23, 2002, the NYPSC issued an Order Adopting Terms of Gas Restructuring Joint Proposal Petition of KeySpan Energy Delivery New York and KeySpan Energy Delivery Long Island for a Multi-Year Restructuring Agreement ("Joint Proposal"). The Joint Proposal did not alter base rate levels, but established a merchant function backout credit of $.21/dth and $.19/dth for KEDNY and KEDLI, respectively. These credits are designed to lower transportation rates charged to transportation only customers. These credits were based on established levels of projected avoided costs and levels of customer migration to non-utility commodity service. Lost revenues resulting from application of these credits will be recovered from firm gas sales customers. The Joint Proposal expired on November 30, 2003. However, by Order dated November 25, 2003 the NYPSC approved tariff amendments that allow KEDNY and KEDLI to continue the merchant function backout credit and the lost revenue recovery mechanism through May 31, 2005.

As a result of circumstances in 2001, including the California energy crisis and the bankruptcy of Enron Corp., state regulators around the country are reassessing the pace of movement toward deregulation. We are unable to predict the outcome or pace of this trend or its ultimate effect on our results of operation, financial condition or cash flows.

On December 20, 2002, New York State Governor George Pataki signed into law the "Energy Consumer Protection Act of 2002" ("Act"). The Act defines energy services companies that provide gas or electric commodity service to customers as utilities subject to the Home Energy Fair Practices Act provisions ("HEFPA") of the New York Public Service Law. Under the Act, in certain circumstances utilities such as KEDNY and KEDLI will be required to suspend distribution service to customers whose commodity service has been terminated by an energy services company. Generally, those energy services companies are required under the Act to provide these customers with the same consumer protections prescribed under HEFPA as are prescribed for full service sales customers of gas distribution companies. Those consumer protections include a series of notices warning of potential service termination, offering deferred payment agreements, and special protections for elderly, blind and disabled customers. Pursuant to the Act, the NYPSC proposed regulations implementing the Act through a notice of Proposed Rulemaking dated January 27, 2004. The Act became effective on June 18, 2003. We cannot predict the impact of the Act on KeySpan's regulated or unregulated operations at this time.

New England

In July 1997, the DTE directed Massachusetts gas distribution companies to undertake a collaborative process with other stakeholders to develop common principles under which comprehensive gas service unbundling might proceed. A settlement agreement by the local distribution companies ("LDCs") and the marketer group regarding model terms and conditions for unbundled transportation service was approved by the DTE in November 1998. In February 1999, the DTE issued its order on how unbundling of natural gas service will proceed. For a five year transition period, the DTE determined that LDC contractual commitments to upstream capacity will be assigned on a mandatory, pro-rata basis to marketers selling gas supply to the LDCs' customers. The approved mandatory assignment method eliminates the possibility that the costs of upstream capacity purchased by the LDCs to serve firm customers will be absorbed by the LDC or other customers through the transition period. The DTE also found that, through the transition period, LDCs will retain primary responsibility for upstream capacity planning and procurement to assure that adequate capacity is available to support customer requirements and growth. The DTE approved the LDCs' Terms and Conditions of Distribution Service that conform to the settled upon model terms and conditions. Since November 1, 2000, all Massachusetts gas customers have the option to purchase their gas supplies from third party sources other than the LDCs. Further, the New Hampshire Public Utility Commission required gas utilities to offer transportation services to all commercial and residential customers starting November 1, 2001. In January 2004, the DTE began a proceeding to re-examine whether the upstream capacity market has been sufficiently competitive to allow voluntary capacity assignment.

We believe that the actions described above strike a balance among competing stakeholder interests in order to most effectively make available the benefits of the unbundled gas supply market to all customers.

Electric Industry

The Ravenswood Facility and our New York City Operations

The NYISO's New York City local reliability rules currently require that 80% of the electric capacity needs of New York City be provided by "in-City" generators. As additional, more efficient electric power plants are built in New York City and the surrounding areas, the requirement that 80% of in-City load be served by in-City generators could be modified. Construction of new transmission facilities could also cause significant changes to the market. If generation and/or transmission facilities are constructed, and/or the availability of our Ravenswood facility deteriorates, then the capacity and energy sales volumes could be adversely affected. We cannot predict, however, when or if new power plants or transmission facilities will be built or the nature of future New York City energy requirements or market design.

Regional Transmission Organizations and Standard Market Design

During 2001, the FERC issued several orders and began several proceedings related to the development of Regional Transmission Organizations ("RTO") and the design of the wholesale energy markets. On September 16, 2004, FERC terminated various RTO proceedings, including the NYISO/ISONE proceeding, because it determined their continuation is no longer necessary to achieve the Commission's objective of establishing RTOs. Nevertheless, the Commission continues to guide the evolution of competitive markets in other proceedings including the development of a Standard Market Design.

On July 31, 2002, FERC issued a Notice of Proposed Rulemaking ("NOPR") intended to establish a standardized national market design and rules for competitive wholesale electric markets ("Standard Market Design" or "SMD"). These rules would apply to transmission owners ("TOs"), independent system operators ("ISOs"), and RTOs. The SMD is intended to create: (i) genuine wholesale competition; (ii) efficient transmission systems; (iii) the right pricing signals for investment in transmission and generation facilities; and (iv) more customer options. How the SMD will be implemented will be based on FERC's final rules in this regard, as well as the subject of various compliance filings by TOs, ISOs, and RTOs. We do not know how the markets will develop nor how these proposed changes will impact the operations of the NYISO or its market rules. Furthermore, we are unable to determine to what extent, if any, this process will impact the Ravenswood facility's financial condition, results of operations or cash flows.

New York Independent System Operator Matters

On May 31, 2002, FERC approved the NYISO's mitigation plan ("the Plan"). The Plan retains existing mitigation measures such as $1,000/MWhr energy price caps, non-spinning reserve bid caps, in-City capacity and energy mitigation measures, the day ahead Automated Mitigation Procedure ("AMP"), and the NYISO's general mitigation authority. In addition, the Plan implemented a new in-City real time automated mitigation procedure. On November 26, 2003, the NYISO filed with FERC a request for tariff revisions reflecting the implementation of enhanced real-time scheduling software. Among other things, the new software included changes to the in-City day-ahead energy mitigation measures. The in-City day-ahead energy mitigation will no longer use the Indian Point 2 price as a proxy for determining whether an energy offer should be mitigated. The NYISO is going to apply its conduct and impact mitigation scheme to in-City offers. This will be applied on an hour by hour basis rather than on a 24-hour basis. Overall the changes are intended to address longstanding issues in the NYISO market and help the NYISO markets reach their full potential. The revisions are expected to lead to prices that reflect actual market and system conditions, including scarcity conditions. FERC approved the tariff revisions on February 11, 2004 and the NYISO will implement the revisions when they complete testing of the software revisions in the fall of 2004. However, the NYISO will implement the revisions associated with the in-City mitigation measures in its existing systems before the summer of 2004. Although prices for various energy products in the NYISO markets have softened, it is not known to what extent each of these proceedings and revised rules may impact the Ravenswood facility's financial condition, results of operations or cash flows.

NYISO Demand Curve Capacity Market Implementation

On March 21, 2003 the NYISO made a filing at FERC seeking approval of a Demand Curve to be used in place of its current deficiency auction for capacity procurement. On May 20, 2003, FERC approved, with some modifications, the Demand Curve to become effective May 21, 2003. On October 23, 2003, FERC denied various requests for rehearing of its order approving the Demand Curve and approved the NYISO's compliance filing. On December 9, 2003, the NYISO filed its first status report with FERC with respect to how the Demand Curve was working. The NYISO report found that there was no evidence of inappropriate withholding of capacity resources and that the Demand Curve was working as intended. On December 22, 2003, the Electric Consumers Resource Council filed an appeal with the DC Circuit Court of Appeals of FERC's May 20, 2003 order approving the Demand Curve and its October 23, 2003 order denying rehearing. This case is still pending and we are unable to determine to what extent, if any, this proceeding will impact the Ravenswood facility's financial condition, results of operations or cash flows.

10-Minute Non-Spinning Reserves - DC Court of Appeals

Due to volatility in the market clearing price of 10-minute spinning and non-spinning reserves during the first quarter of 2000, the NYISO requested that FERC approve a bid cap on reserves as well as requiring a refunding of so called alleged "excess payments" received by sellers, including Ravenswood. On May 31, 2000, FERC issued an order that granted approval of a \$2.52 per MWh bid cap for 10 minute non-spinning reserves, plus payments for the opportunity cost of not making energy sales. The other requests, such as a bid cap for spinning reserves, retroactive refunds, recalculation of reserve prices for March 2000, and convening a technical conference and settlement proceeding, were rejected.

The NYISO, Con Edison, Niagara Mohawk Power Corporation and Rochester Gas and Electric (joint petitioners) each individually appealed FERC's order to Federal court. The appeals were consolidated into one case by the court. On November 7, 2003 the United States Court of Appeals for the District of Columbia (the "Court") issued its decision in the case of *Consolidated Edison Company of New York, Inc., v. Federal Energy Regulatory Commission* ("Decision"). Essentially, the Court found errors in the Commission's decision and remanded some issues in the case back to the Commission for further explanation and action. The Commission has not acted on the remand. At this time we can not predict the outcome of the remand proceeding.

Foreign Currency Fluctuations

We follow the principles of SFAS 52, "Foreign Currency Translation" for recording our investments in foreign affiliates. At December 31, 2003, the net assets of these affiliates was approximately \$323 million and at December 31, 2003, the accumulated after-tax foreign currency translation included in Other Comprehensive Income was a credit of \$26.5 million. (See Note 1 to the Consolidated Financial Statements "Summary of Significant Accounting Policies.")

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Financially-Settled Commodity Derivative Instruments – Non-Regulated Hedging Activities: From time to time, KeySpan subsidiaries have utilized derivative financial instruments, such as futures, options and swaps, for the purpose of hedging the cash flow variability associated with changes in commodity prices. KeySpan is exposed to commodity price risk primarily with regard to its gas exploration and production activities and its electric generating facilities. Derivative financial instruments are employed by Houston Exploration to hedge cash flow variability associated with forecasted sales of natural gas. The Ravenswood facility uses derivative financial instruments to hedge the cash flow variability associated with the purchase of natural gas and oil that will be consumed during the generation of electricity. The Ravenswood facility also hedges the cash flow variability associated with a portion of peak electric energy sales.

For derivative instruments associated with gas exploration and production activities, KeySpan uses standard New York Mercantile Exchange ("NYMEX") future price quotes to value swap positions and published volatility in its Black-Scholes calculation for outstanding options. Further, KeySpan uses standard NYMEX futures prices to value gas futures contracts and market quoted forward prices to value oil swap and natural gas basis swap contracts associated with its Ravenswood facility. We also use market quoted forward prices to value electric derivatives associated with the Ravenswood facility.

The following tables set forth selected financial data associated with these derivative financial instruments that were outstanding at December 31, 2003.

Type of Contract	Year of Maturity	Volumes (mmcf)	Floor ($)	Ceiling ($)	Fixed Price ($)	Current Price ($)	Fair Value ($000)
Gas							
Collars	2004	64,100	3.75-4.13	5.05-6.02	-	5.11 - 6.19	(29,449)
	2005	36,500	4.50	5.50	-	4.65 - 5.61	(1,534)
Put Options - Short Natural Gas	2004	9,100	-	-	5.00	5.11 - 5.26	4,228
Swaps/Futures - Short Natural Gas	2004	14,640	-	-	4.96	5.11 - 6.19	(6,912)
	2005	18,250	-	-	4.77	4.65 - 5.61	(3,194)
Swaps/Futures - Long Natural Gas	2005	10	-	-	4.95	4.65	(6)
		142,600					(36,867)

Type of Contract	Year of Maturity	Volumes (Barrels)	Fixed Price ($)	Current Price ($)	Fair Value ($000)
Oil					
Swaps - Long Fuel Oil	2004	100,548	20.55 - 29.60	28.28 - 32.42	361
	2005	28,000	24.65 - 27.25	27.35	24
		128,548			385

Type of Contract	Year of Maturity	MWh	Fixed Price ($)	Current Price ($)	Fair Value ($000)
Electricity					
Swaps - Energy	2004	580,000	14.00 - 28.00	14.10 - 39.33	259

The following tables detail the changes in and sources of fair value for the above derivatives:

(In Thousands of Dollars) *Change in Fair Value of Derivative Hedging Instruments*	2003 ($000)
Fair value of contracts at January 1,	$ (32,628)
Net losses on contracts realized	35,449
(Decrease) in fair value of all open contracts	(39,045)
Fair value of contracts outstanding at December 31,	$ (36,224)

(In Thousands of Dollars)

	Fair Value of Contracts		
Sources of Fair Value	Maturity In 12 Months	Maturity in 2005	Total Fair Value
Prices actively quoted	$ (23,142)	$ (3,677)	$ (26,819)
Prices provided by external sources	(3)	-	(3)
Prices based on models and other valuation methods	(8,992)	(1,054)	(10,046)
Local published indicies	620	24	644
	$ (31,517)	$ (4,707)	$ (36,224)

Firm Gas Sales Derivative Instruments - Regulated Utilities: We use derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with our Gas Distribution operations. The accounting for these derivative instruments is subject to SFAS 71 "Accounting for the Effects of Certain Types of Regulation." Therefore, changes in the fair value of these derivatives have been recorded as a regulatory asset or regulatory liability on the Consolidated Balance Sheet. Gains or losses on the settlement of these contracts are initially deferred and then refunded to or collected from our firm gas sales customers consistent with regulatory requirements.

The following table sets forth selected financial data associated with these derivative financial instruments that were outstanding at December 31, 2003.

Type of Contract	Year of Maturity	Volumes (mmcf)	Floor ($)	Ceiling ($)	Fixed Price ($)	Current Price ($)	Fair Value ($000)
Options	2004	6,460	3.75 - 5.00	4.75 - 6.00	-	5.11 - 6.19	3,008
Swaps	2004	17,122	-	-	4.42 - 6.23	5.11 - 6.19	6,501
	2005	3,310	-	-	4.61 - 5.65	4.65 - 5.61	352
		26,892					9,861

See Note 8 to the Consolidated Financial Statements "Hedging, Derivative Financial Instruments and Fair Values" for a further description of all our derivative instruments.

Item 8. *Financial Statements and Supplementary Data*

CONSOLIDATED BALANCE SHEET

(In Thousands of Dollars)	Year Ended December 31, 2003	2002
ASSETS		
Current Assets		
Cash and temporary cash investments	**$ 205,751**	$ 170,617
Accounts receivable	**1,029,459**	1,122,022
Unbilled revenue	**505,633**	473,060
Allowance for uncollectible accounts	**(79,184)**	(63,029)
Gas in storage, at average cost	**488,521**	297,060
Material and supplies, at average cost	**121,415**	113,519
Other	**115,304**	93,980
	2,386,899	2,207,229
Investments and Other	**248,565**	264,729
Property		
Gas	**6,522,251**	6,125,529
Electric	**2,636,537**	1,974,352
Other	**425,576**	394,374
Accumulated depreciation	**(2,610,876)**	(2,374,772)
Gas exploration and production, at cost	**3,088,242**	2,438,998
Accumulated depletion	**(1,167,427)**	(973,889)
	8,894,303	7,584,592
Deferred Charges		
Regulatory assets	**564,985**	438,516
Goodwill and other intangible assets, net of amortization	**1,809,712**	1,796,225
Other	**722,320**	688,759
	3,097,017	2,923,500
Total Assets	**$ 14,626,784**	$ 12,980,050

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET

(In Thousands of Dollars)	Year Ended December 31, 2003	2002
LIABILITIES AND CAPITALIZATION		
Current Liabilities		
Current redemption of long-term debt	**$ 1,471**	$ 11,413
Accounts payable and other liabilities	**1,141,597**	1,096,654
Commercial paper	**481,900**	915,697
Dividends payable	**72,289**	64,714
Taxes accrued	**46,580**	51,276
Customer deposits	**40,370**	38,387
Interest accrued	**64,609**	77,092
	1,848,816	2,255,233
Deferred Credits and Other Liabilities		
Regulatory liabilities:		
Miscellaneous liabilities	**104,034**	84,479
Removal costs recovered	**450,034**	-
Removal costs recovered	**-**	365,744
Deferred income tax	**1,273,651**	877,013
Postretirement benefits and other reserves	**961,962**	759,731
Other	**121,790**	154,907
	2,911,471	2,241,874
Commitments and Contingencies (See Note 7)	**-**	-
Capitalization		
Common stock	**3,487,645**	3,005,354
Retained earnings	**621,430**	522,835
Accumulated other comprehensive income	**(68,640)**	(108,423)
Treasury stock	**(378,487)**	(475,174)
Total common shareholders' equity	**3,661,948**	2,944,592
Preferred stock	**83,568**	83,849
Long-term debt	**5,611,432**	5,224,081
Total Capitalization	**9,356,948**	8,252,522
Minority Interest in Subsidiary Companies	**509,549**	230,421
Total Liabilities and Capitalization	**$ 14,626,784**	$ 12,980,050

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF INCOME

(In Thousands of Dollars, Except Per Share Amounts)	Year Ended December 31, **2003**	2002	2001
Revenues			
Gas Distribution	**$ 4,161,272**	$ 3,163,761	$ 3,613,551
Electric Services	**1,503,086**	1,421,043	1,421,079
Energy Services	**641,432**	938,761	1,100,167
Gas Exploration and Production	**501,255**	357,451	400,031
Energy Investments	**108,116**	89,650	98,287
Total Revenues	**6,915,161**	5,970,666	6,633,115
Operating Expenses			
Purchased gas for resale	**2,495,102**	1,653,273	2,171,113
Fuel and purchased power	**414,633**	395,860	538,532
Operations and maintenance	**2,005,796**	2,101,897	2,114,759
Depreciation, depletion and amortization	**574,074**	514,613	559,138
Operating taxes	**418,236**	381,767	448,924
Total Operating Expenses	**5,907,841**	5,047,410	5,832,466
Gain on sale of property	**15,123**	4,730	-
Income from equity investments	**19,214**	14,096	13,129
Operating Income	**1,041,657**	942,082	813,778
Other Income and (Deductions)			
Interest charges	**(307,694)**	(301,504)	(353,470)
Sale of subsidiary stock	**13,356**	-	-
Cost of debt redemption	**(24,094)**	-	-
Minority interest	**(63,852)**	(24,918)	(40,847)
Other	**42,119**	25,169	34,924
Total Other Income and (Deductions)	**(340,165)**	(301,253)	(359,393)
Income Taxes			
Current	**(104,355)**	(24,212)	101,738
Deferred	**381,666**	267,691	108,955
Total Income Taxes	**277,311**	243,479	210,693
Earnings from Continuing Operations	**424,181**	397,350	243,692
Discontinued Operations			
Income (loss) from operations, net of tax	**-**	(3,356)	10,918
Loss on disposal, net of tax	**-**	(16,306)	(30,356)
Loss from Discontinued Operations	**-**	(19,662)	(19,438)
Cumulative Change in Accounting Principles, net of tax	**(37,451)**	-	-
Net Income	**386,730**	377,688	224,254
Preferred stock dividend requirements	**5,844**	5,753	5,904
Earnings for Common Stock	**$ 380,886**	$ 371,935	$ 218,350
Basic Earnings Per Share:			
Continuing Operations, less preferred stock dividends	**$ 2.64**	$ 2.77	$ 1.72
Discontinued Operations	**-**	(0.14)	(0.14)
Change in Accounting Principles	**(0.23)**	-	-
Basic Earnings Per Share	**$ 2.41**	$ 2.63	$ 1.58
Diluted Earnings Per Share			
Continuing Operations, less preferred stock dividends	**$ 2.62**	$ 2.75	$ 1.70
Discontinued Operations	**-**	(0.14)	(0.14)
Change in Accounting Principles	**(0.23)**	-	-
Diluted Earnings Per Share	**$ 2.39**	$ 2.61	$ 1.56
Average Common Shares Outstanding (000)	**158,256**	141,263	138,214
Average Common Shares Outstanding - Diluted (000)	**159,232**	142,300	139,221

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

(In Thousands of Dollars)	Year Ended December 31, 2003	2002	2001
Operating Activities			
Net income	**$ 386,730**	$ 377,688	$ 224,254
Adjustments to reconcile net income to net cash provided by (used in) operating activities			
Depreciation, depletion and amortization	**574,074**	514,613	559,138
Deferred income tax	**189,275**	90,724	108,955
Income from equity investments	**(18,038)**	(14,096)	(13,129)
Dividends from equity investments	**2,807**	3,905	7,570
Amortization of interest rate swap	**(9,861)**	-	-
(Gain) loss on disposal of subsidiary stock	**(13,356)**	-	19,438
Gain on sale of property	**(15,123)**	(4,730)	-
Gain from class action settlement	**-**	-	(33,510)
Provision for losses on contracting business	**-**	-	63,682
Change in accounting principle	**37,451**	-	-
Environmental reserve adjustment	**(10,459)**	-	-
Minority interest	**63,852**	24,918	40,847
Changes in assets and liabilities			
Accounts receivable	**77,750**	(259,454)	401,976
Materials and supplies, fuel oil and gas in storage	**(199,357)**	42,508	(43,856)
Accounts payable and accrued expenses	**199,980**	18,179	(400,636)
Reserve payments	**(36,486)**	(23,369)	-
Other	**(44,596)**	(39,394)	(44,548)
Net Cash Provided by Operating Activities	**1,184,643**	731,492	890,181
Investing Activities			
Construction expenditures	**(1,011,716)**	(1,061,022)	(1,059,759)
Other Investments	**(211,370)**	(27,579)	-
Proceeds from sale of property and subsidiary stock	**309,696**	179,840	18,458
Issuance of long-term note	**(55,000)**	-	-
Other	**-**	-	(6)
Net Cash (Used in) Investing Activities	**(968,390)**	(908,761)	(1,041,307)
Financing Activities			
Treasury stock issued	**96,687**	86,710	88,786
Common stock issuance	**473,573**	-	-
Issuance of long-term debt	**1,024,912**	549,280	812,116
Payment of long-term debt	**(605,625)**	(124,991)	(183,410)
Payment of commercial paper	**(433,797)**	(132,753)	(251,787)
Redemption of promissory notes	**(447,005)**	-	-
Redemption of preferred stock	**(14,293)**	-	-
Common and preferred stock dividends paid	**(280,560)**	(256,656)	(251,502)
Termination of interest rate swaps	**-**	57,415	-
Other	**4,989**	9,629	12,846
Net Cash (Used in) Provided by Financing Activities	**(181,119)**	188,634	227,049
Net Increase in Cash and Cash Equivalents	**$ 35,134**	$ 11,365	$ 75,923
Cash and Cash Equivalents at Beginning of Period	**170,617**	159,252	83,329
Cash and Cash Equivalents at End of Period	**$ 205,751**	$ 170,617	$ 159,252
Interest Paid	**$ 355,136**	$ 343,933	$ 328,910
Income Tax Paid	**$ 65,495**	$ 98,344	$ 128,558

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF RETAINED EARNINGS

(In Thousands of Dollars)	Year Ended December 31, 2003	2002	2001
Balance at Beginning of Period	**$ 522,835**	$ 452,206	$ 480,639
Net Income for Period	**386,730**	377,688	224,254
	909,565	829,894	704,893
Deductions:			
Cash dividends declared on common stock	**282,291**	252,175	246,783
Cash dividends declared on preferred stock	**5,844**	5,753	5,904
MEDS Equity Units	**-**	49,131	-
Balance at End of Period	**$ 621,430**	$ 522,835	$ 452,206

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(In Thousands of Dollars)	Year Ended December 31, 2003	2002	2001
Net Income	**$ 386,730**	$ 377,688	$ 224,254
Other comprehensive income, net of tax			
Net losses (gains) on derivative instruments	**23,042**	(17,033)	(27,690)
Reclassification adjustment for other gains reclassified to net income	**-**	-	(3,242)
Foreign currency translation adjustments	**28,696**	9,759	(9,627)
Unrealized gains (losses) on marketable securities	**8,480**	(10,019)	(5,464)
Premium on derivative instrument	**(3,437)**	-	-
Accrued unfunded pension obligation	**8,380**	(55,768)	(13,262)
Unrealized (losses) gains on derivative financial instruments	**(25,379)**	(39,845)	62,943
Other comprehensive income (loss), net of tax	**39,782**	(112,906)	3,658
Comprehensive Income	**$ 426,512**	$ 264,782	$ 227,912
Related tax (benefit) expense			
Net losses (gains) on derivative instruments	**12,407**	(9,172)	$ (14,910)
Reclassification adjustment for other gains reclassified to net income	-	-	(1,746)
Foreign currency translation adjustments	**15,451**	5,255	(5,184)
Unrealized gains (losses) on marketable securities	**4,568**	(5,395)	(2,942)
Accrued unfunded pension obligation	**4,513**	(30,029)	(7,140)
Premium on derivative instrument	**(1,851)**	-	-
Unrealized (losses) gains on derivative financial instruments	**(13,666)**	(21,454)	33,892
Total Tax (Benefit) Expense	**$ 21,422**	$ (60,795)	$ 1,970

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CAPITALIZATION

(In Thousands of Dollars)	December 31, 2003	2002	2003	2002
Common Shareholders' Equity	**Shares Issued**			
Common stock, $0.01 par Value	**172,737,654**	158,837,654	**$ 1,727**	$ 1,588
Premium on capital stock			**3,485,918**	3,003,766
Retained earnings			**621,430**	522,835
Other comprehensive income			**(68,640)**	(108,423)
Treasury stock	**13,073,219**	16,412,880	**(378,487)**	(475,174)
Total Common Shareholders' Equity	**159,664,435**	142,424,774	**3,661,948**	2,944,592
Preferred Stock - No Redemption Required				
Par Value $100 per share				
7.07% Series B -private placement	**553,000**	553,000	**55,300**	55,300
7.17% Series C-private placement	**197,000**	197,000	**19,700**	19,700
6.00% Series A-private placement	**85,676**	88,486	**8,568**	8,849
Total Preferred Stock - No Redemption Required			**83,568**	83,849
Long - Term Debt	**Interest Rate**	**Maturity**		
Notes				
Medium term notes	4.65% - 9.75%	2005 - 2033	**3,185,000**	2,885,000
Senior secured notes	5.42% - 6.16%	2008-2013	**96,425**	-
Senior subordinated notes	7.0%	2013	**175,000**	100,000
Total Notes			**3,456,425**	2,985,000
Gas Facilities Revenue Bonds	Variable	2020	**125,000**	125,000
	5.50% - 6.95%	2020 - 2026	**523,500**	523,500
Total Gas Facilities Revenue Bonds			**648,500**	648,500
Promissory Notes to LIPA				
Debentures	8.20%	2023	**-**	270,000
Pollution control revenue bonds	5.15%	2016	**108,022**	108,022
Electric facilities revenue bonds	5.30%	2023 - 2025	**47,400**	224,405
Total Promissory Notes to LIPA			**155,422**	602,427
MEDS Equity Units	8.75%	2005	**460,000**	460,000
Industrial Development Bonds	5.25%	2027	**128,275**	-
First Mortgage Bonds	5.50% - 10.10%	2003 - 2028	**153,186**	163,625
Authority Financing Notes	Variable	2027 - 2028	**66,005**	66,005
Other Subsidiary Debt			**145,612**	304,298
Ravenswood Master Lease & Capital Leases		2005 - 2022	**425,262**	13,884
Subtotal			**5,638,687**	5,243,739
Unamortized interest rate hedge and debt discount			**(69,243)**	(75,265)
Derivative impact on debt			**43,459**	67,020
Less: current maturities			**1,471**	11,413
Total Long-Term Debt			**5,611,432**	5,224,081
Total Capitalization			**$ 9,356,948**	$ 8,252,522

See accompanying Notes to the Consolidated Financial Statements.

Notes to the Consolidated Financial Statements

Note 1. Summary of Significant Accounting Policies

A. Organization of the Company

KeySpan Corporation, a New York corporation, was formed in May 1998, as a result of the business combination of KeySpan Energy Corporation, the parent of The Brooklyn Union Gas Company, and certain businesses of the Long Island Lighting Company ("LILCO"). On November 8, 2000, KeySpan acquired Eastern Enterprises ("Eastern"), a Massachusetts business trust, and the parent of several gas utilities operating in Massachusetts. Also on November 8, 2000, Eastern acquired EnergyNorth, Inc. ("ENI"), the parent of a gas utility operating in central New Hampshire. KeySpan Corporation will be referred to in these notes to the Consolidated Financial Statements as "KeySpan", "we", "us" and "our."

Our core business is gas distribution, conducted by our six regulated gas utility subsidiaries: The Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York ("KEDNY") and KeySpan Gas East Corporation d/b/a KeySpan Energy Delivery Long Island ("KEDLI") distribute gas to customers in the Boroughs of Brooklyn, Staten Island and a portion of the Borough of Queens in New York City, and the counties of Nassau and Suffolk on Long Island and the Rockaway Peninsula in Queens, respectively; Boston Gas Company, Colonial Gas Company and Essex Gas Company, each doing business as KeySpan Energy Delivery New England ("KEDNE"), distribute gas to customers in southern, eastern and central Massachusetts; and EnergyNorth Natural Gas, Inc., d/b/a KeySpan Energy Delivery New England distributes gas to customers in central New Hampshire. Together, these companies distribute gas to approximately 2.5 million customers throughout the Northeast.

We also own, lease and operate electric generating plants on Long Island and in New York City. Under contractual arrangements, we provide power, electric transmission and distribution services, billing and other customer services for approximately 1.0 million electric customers of the Long Island Power Authority ("LIPA").

Our other subsidiaries are involved in gas and oil exploration and production; gas storage; liquefied natural gas storage; wholesale and retail electric marketing; appliance service; plumbing; heating, ventilation, air conditioning and other mechanical services; large energy-system ownership, installation and management; fiber optic services; and engineering and consulting services. We also invest in, and participate in the development of natural gas pipelines; natural gas processing plants; electric generation, and other energy-related projects, domestically and internationally. (See Note 2, "Business Segments" for additional information on each operating segment.)

We are a registered holding company under the Public Utility Holding Company Act of 1935 ("PUHCA"), as amended. Therefore, our corporate and financial activities and those of our subsidiaries, including their ability to pay dividends to us, are subject to regulation by the Securities and Exchange Commission ("SEC"). Under our holding company structure, we have no independent operations or source of income of our own and conduct all of our operations through our subsidiaries and, as a result, we depend on the earnings and cash flow of, and dividends or distributions from, our subsidiaries to provide the funds necessary to meet our debt and contractual obligations. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operations of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation by state regulatory authorities.

B. Basis of Presentation

The Consolidated Financial Statements presented herein reflect the accounts of KeySpan and its subsidiaries. Most of our subsidiaries are fully consolidated in the financial information presented, except for certain subsidiary investments in the Energy Investments segment which are accounted for on the equity method as we do not have a controlling voting interest or otherwise have control over the management of such companies. All significant intercompany transactions have been eliminated. Certain reclassifications were made to conform prior period financial statements to current period financial statement presentation. For December 31, 2003, 2002 and 2001, we reclassified income from equity investments and property sales from other income and (deductions) to operating income on the Consolidated Statement of Income. On the 2001 Consolidated Statement of Cash Flows, minority interest, changes in assets and liabilities – other, and (gain) loss on disposal of subsidiary stock amounts have been reclassified. The amount related to the loss from discontinued operations has been separately identified as (gain) loss on disposal of subsidiary stock. In addition, minority interest was previously disclosed as a component of changes in assets and liabilities – other; it has since been reclassified as a separate line item for all periods presented.

The preparation of financial statements in conformity with generally accepted accounting principles ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities 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.

C. Accounting for the Effects of Rate Regulation

The accounting records for our six regulated gas utilities are maintained in accordance with the Uniform System of Accounts prescribed by the Public Service Commission of the State of New York ("NYPSC"), the New Hampshire Public Utility Commission ("NHPUC"), and the Massachusetts Department of Telecommunications and Energy ("DTE"). Our electric generation subsidiaries are not subject to state rate regulation, but they are subject to Federal Energy Regulatory Commission ("FERC") regulation. Our financial statements reflect the ratemaking policies and actions of these regulators in conformity with GAAP for rate-regulated enterprises.

Four of our six regulated gas utilities (KEDNY, KEDLI, Boston Gas Company and EnergyNorth Natural Gas, Inc.) and our Long Island based electric generation subsidiaries are subject to the provisions of Statement of Financial Accounting Standards ("SFAS") 71, "Accounting for the Effects of Certain Types of Regulation." This statement recognizes the ability of regulators, through the ratemaking process, to create future economic benefits and obligations affecting rate-regulated companies. Accordingly, we record these future economic benefits and obligations as regulatory assets and regulatory liabilities on the Consolidated Balance Sheet, respectively.

In separate merger related orders issued by the DTE, the base rates charged by Colonial Gas Company and Essex Gas Company have been frozen at their current levels for ten-year periods, ending 2009 and 2008, respectively. Due to the length of these base rate freezes, the Colonial and Essex Gas Companies had previously discontinued the application of SFAS 71.

The following table presents our net regulatory assets at December 31, 2003 and December 31, 2002.

(In Thousands of Dollars)	December 31, 2003	December 31, 2002
Regulatory Assets		
Regulatory tax asset	$ 47,236	$ 53,401
Property taxes	64,854	58,400
Environmental costs	296,888	182,163
Postretirement benefits	93,284	82,563
Costs associated with the KeySpan/LILCO transaction	50,585	61,989
Derivative financial instruments	6,909	-
Other	5,229	-
Total Regulatory Assets	$ 564,985	$ 438,516
Miscellaneous Regulatory Liabilities	(104,034)	(84,479)
Net Regulatory Assets	460,951	354,037
Removal Costs Recovered	(450,034)	-
	$ 10,917	$ 354,037

The regulatory assets above are not included in rate base. However, we record carrying charges on the property tax and costs associated with the KeySpan/LILCO transaction cost deferrals. We also record carrying charges on our regulatory liabilities. The remaining regulatory assets represent, primarily, costs for which expenditures have not yet been made, and therefore, carrying charges are not recorded. We anticipate recovering these costs in our gas rates concurrently with future cash expenditures. If recovery is not concurrent with the cash expenditures, we will record the appropriate level of carrying charges. Deferred gas costs of $53.4 million and $61.8 million at December 31, 2003 and December 31, 2002, respectively are reflected in accounts receivable on the Consolidated Balance Sheet. Deferred gas costs are subject to current recovery from customers.

We estimate that full recovery of our regulatory assets will not exceed 10 years, except for the regulatory tax asset, which will be recovered over the estimated lives of certain utility property.

Rate regulation is undergoing significant change as regulators and customers seek lower prices for utility service and greater competition among energy service providers. In the event that regulation significantly changes the opportunity to recover costs in the future, all or a portion of our regulated operations may no longer meet the criteria for the application of SFAS 71. In that event, a write-down of all or a portion of our existing regulatory assets and liabilities could result. If we were unable to continue to apply the provisions of SFAS 71 for any of our rate regulated subsidiaries, we would apply the provisions of SFAS 101, "Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement 71." We estimate that the write-off of all net regulatory assets at December 31, 2003, before consideration of removal costs recovered, could result in a charge to net income of $300 million or $1.89 per share, which would be classified as an extraordinary item. In 2003, KeySpan implemented SFAS 143 "Accounting for Asset Retirement Obligations" and reclassified cost of removal accruals from accumulated depreciation to regulatory liabilities. For the 2002 Consolidated Balance Sheet presentation, these accruals are reflected as a separate line item in deferred credits and other liabilities. In management's opinion, our regulated subsidiaries that are currently subject to the provisions of SFAS 71 will continue to be subject to SFAS 71 for the foreseeable future.

D. Revenues

Gas Distribution: Utility gas customers are billed monthly or bi-monthly on a cycle basis. Revenues include unbilled amounts related to the estimated gas usage that occurred from the most recent meter reading to the end of each month.

The cost of gas used is recovered when billed to firm customers through the operation of gas adjustment clauses ("GAC") included in utility tariffs. The GAC provision requires periodic reconciliation of recoverable gas costs and GAC revenues. Any difference is deferred pending recovery from or refund to firm customers. Further, net revenues from tariff gas balancing services, off-system sales and certain on-system interruptible sales are refunded, for the most part, to firm customers subject to certain sharing provisions.

The New York and Long Island gas utility tariffs contain weather normalization adjustments that largely offset shortfalls or excesses of firm net revenues (revenues less gas costs and revenue taxes) during a heating season due to variations from normal weather. Revenues are adjusted each month the clause is in effect and are generally included in rates in the following month. The New England gas utility rate structures contain no weather normalization feature, therefore their net revenues are subject to weather related demand fluctuations.

Electric Services: Electric revenues are derived from billings to LIPA for management of LIPA's transmission and distribution ("T&D") system, electric generation, and procurement of fuel.

KeySpan manages the day-to-day operations, maintenance and capital improvements of the T&D system under a Management Service Agreement ("MSA"). In exchange for providing the services, KeySpan earns a $10 million annual management fee. Annual service incentives or penalties exist under the MSA if certain targets are achieved or not achieved. In addition, we can earn certain incentives for budget underruns associated with the day-to-day operations, maintenance and capital improvements of LIPA's T&D system. These incentives provide for us to (i) retain 100% on the first $5 million in annual budget underruns, and (ii) retain 50% of additional annual underruns up to 15% of the total cost budget, thereafter all savings accrue to LIPA. With respect to cost overruns, we will absorb the first $15 million of overruns, with a sharing of overruns above $15 million. There are certain limitations on the amount of cost sharing of overruns.

In addition, KeySpan sells to LIPA under a Power Supply Agreement ("PSA") all of the capacity and, to the extent requested, energy conversion services from our existing Long Island based oil and gas-fired generating plants. Sales of capacity and energy conversion services are made under rates approved by the FERC. Rates charged to LIPA include a fixed and variable component. The variable component is billed to LIPA on a monthly per megawatt hour basis and is dependent on the number of megawatt hours dispatched. The PSA provides incentives and penalties that can total $4 million annually for the maintenance of the output capability and the efficiency of the generating facilities.

KeySpan also procures and manages fuel supplies on behalf of LIPA, under an Energy Management Agreement ("EMA"), to fuel the generating facilities under contract to it and perform off-system capacity and energy purchases on a least-cost basis to meet LIPA's needs. In exchange for these services we earn an annual fee of $1.5 million. In addition, we arrange for off-system sales on behalf of LIPA of excess output from the generating facilities and other power supplies either owned or under contract to LIPA. LIPA is entitled to two-thirds of the profit from any off-system energy sales. In addition, the EMA provides incentives and penalties that can total $7 million annually for performance related to fuel purchases and off-system power purchases.

KeySpan Glenwood Energy Center LLC and KeySpan Port Jefferson Energy Center LLC have entered into 25 year Power Purchase Agreements with LIPA (the "PPAs"). Under the terms of the PPAs, these subsidiaries sell capacity, energy conversion services and ancillary services to LIPA. Each plant is designed to produce 79.9 megawatts ("MW"). Under the PPAs, LIPA pays a monthly capacity fee, which guarantees full recovery of each plant's construction costs, as well as an appropriate rate of return on investment. The PPAs also obligate LIPA to pay for each plant's costs of operation and maintenance. These costs are billed on a monthly estimated basis and are subject to true-up for actual costs incurred.

In addition, electric revenues are derived from our investment in the 2,200 megawatt Ravenswood electric generation facility ("Ravenswood facility"), which we acquired in June 1999. (See Note 7 "Contractual Obligations, Financial Guarantees and Contingencies" for a description of the Ravenswood transaction.) We realize revenues from our investment in the Ravenswood facility through the sale, at wholesale, of energy, capacity, and ancillary services to the New York Independent System Operator ("NYISO"). Energy and ancillary services are sold through a bidding process into the NYISO energy markets on a day ahead or real time basis.

Energy Services: Revenues earned by our Energy Services segment for mechanical and other contracting services are derived from service rendered under fixed price, cost-plus, guaranteed maximum price, and time and materials-type contracts and generally recognized on the percentage-of-completion method. Percentage-of-completion is measured principally by the percentage of costs incurred to date for each contract to the estimated total costs for each contract at completion. Provisions for estimated losses on uncompleted contracts are made in the period in which such losses are determined. In the case of customer change orders, estimated recoveries are included for work performed in forecasting ultimate profitability on certain contracts. Due to uncertainties inherent in the estimation process, changes in job performance, job conditions, estimated profitability and final contract settlements may result in revisions to estimated costs and, therefore, revenues. Such revisions to costs and income are recognized in the period in which the revisions are determined.

Costs and estimated earnings in excess of billings on uncompleted contracts arise when revenues have been recorded but the amounts cannot be billed under the terms of the contracts. Such amounts are recoverable from customers upon various measures of performance, including achievement of certain milestones, completion of specified units or completion of the contract.

Also included in costs and estimated earnings on uncompleted contracts are amounts to be collected from customers for changes in contract specifications or design, contract change orders in dispute or unapproved as to scope or price, or other customer-related causes of unanticipated additional contract costs. These amounts are recorded at their estimated net realizable value when realization is probable and can be reasonably estimated. Claims and unapproved change orders involve negotiation and, in certain cases, litigation. Unapproved change orders and claims also involve the use of estimates, and it is reasonably possible that revisions to the estimated recoverable amounts of recorded change orders and claims may be made in the near-term. If KeySpan does not successfully resolve these matters, an expense may be required, in addition to amounts that have been previously provided for. Claims against KeySpan are recognized when a loss is considered probable and amounts are reasonably determinable.

Energy service and maintenance revenues are recognized as earned or over the life of the service contract, as appropriate. Energy sales made by our electric marketing subsidiary are recorded upon delivery of the related commodity. Fiber optic service revenue is recognized upon delivery of service access. We have unearned revenue recorded in deferred credits and other liabilities – other on the Consolidated Balance Sheet totaling $23.8 million and $19.2 million for the years ended December 31, 2003, and December 31, 2002, respectively. These balances represent primarily unearned revenues for service contracts and leases on fiber optic cables. The unearned revenues from the service contracts are generally amortized to income within one year, while the lease related unearned revenues are amortized over periods ranging from five to 30 years.

Gas Exploration and Production: Natural gas and oil revenues earned by our gas exploration and production activities are recognized using the entitlements method of accounting. Under this method of accounting, income is recorded based on the net revenue interest in production or nominated deliveries. Production gas volume imbalances are incurred in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under deliveries are recorded as assets. Imbalances are reduced either by subsequent recoupment of over and under deliveries or by cash settlement, as required by applicable contracts. Production imbalances are marked-to-market at the end of each month using the market price at the end of each period.

E. Utility and Other Property - Depreciation and Maintenance

Property, principally utility gas property is stated at original cost of construction, which includes allocations of overheads, including taxes, and an allowance for funds used during construction. The rates at which KeySpan subsidiaries capitalized interest for the years ended December 31, 2001 through 2003 ranged from 2.95% to 10.67%. Capitalized interest for 2003, 2002 and 2001 was $13.5 million, $19.7 million and $8.5 million, respectively.

Depreciation is provided on a straight-line basis in amounts equivalent to composite rates on average depreciable property. The cost of property retired is charged to accumulated depreciation.

KeySpan recovers certain asset retirement costs through rates charged to customers as a portion of depreciation expense. At December 31, 2003 and 2002, KeySpan had costs recovered in excess of costs incurred totaling $450 million and $366 million, respectively. These amounts are reflected as a regulatory liability for 2003 and in deferred credits and other liabilities for 2002 on the Consolidated Balance Sheet.

The cost of repair and minor replacement and renewal of property is charged to maintenance expense. The composite rates on average depreciable property were as follows:

	Year Ended December 31,		
	2003	2002	2001
Electric	3.81%	3.88%	3.78%
Gas	3.37%	3.44%	3.40%

We also had $425.6 million of other property at December 31, 2003, which is not reflected in "rate base" for utility rate making purposes. This property consists of assets held primarily by our Corporate Service subsidiary of $320.3 million and $105.3 million in Energy Services assets. The Corporate Service assets consist largely of land, buildings, office equipment and furniture, vehicles, computer and telecommunications equipment and systems. These assets have depreciable lives ranging from three to 40 years. We allocate the carrying cost of these assets to our operating subsidiaries through our PUHCA allocation methodology. Energy Services assets consist largely of construction equipment and fiber optic cable and related electronics and have service lives ranging from seven to 40 years.

KeySpan's repair and maintenance costs, including planned major maintenance in the Electric Services segment for turbine and generator overhauls, are expensed as incurred unless they represent replacement of property to be capitalized. Planned major maintenance cycles primarily range from seven to eight years. Smaller periodic overhauls are performed approximately every 18 months.

F. Gas Exploration and Production Property - Depletion

At December 31, 2003, we had exploration and production property in the amount of $3.1 billion related to our investments in natural gas and oil properties. These assets are accounted for under the full cost method of accounting. Under the full cost method, costs of acquisition, exploration and development of natural gas and oil reserves are capitalized into a "full cost pool" as incurred. Unproved properties and related costs are excluded from the depletion and amortization base until a determination as to the existence of proved reserves. Properties are depleted and charged to operations using the unit of production method using proved reserve quantities.

These investments consist of our 55% ownership interest in The Houston Exploration Company ("Houston Exploration"), an independent natural gas and oil exploration company, as well as KeySpan Exploration and Production, LLC ("KeySpan Exploration"), our wholly-owned subsidiary engaged in a joint venture with Houston Exploration. To the extent that such capitalized costs (net of accumulated depletion) less deferred taxes exceed the present value (using a 10% discount rate) of estimated future net cash flows from proved natural gas and oil reserves and the lower of cost or fair value of unproved properties, less deferred taxes, such excess costs are charged to operations, but would not have an impact on cash flows. Once incurred, such impairment of gas properties is not reversible at a later date even if gas prices increase.

The ceiling test is calculated using natural gas and oil prices in effect as of the balance sheet date, held flat over the life of the reserves. We use derivative financial instruments that qualify for hedge accounting under SFAS 133 "Accounting for Derivative Instruments and Hedging Activities," to hedge the volatility of natural gas prices. In accordance with current SEC guidelines, we have included estimated future cash flows from our hedging program in the ceiling test calculation. As of December 31, 2003, we estimated, using a wellhead price of $5.79 per MCF, that our capitalized costs did not exceed the ceiling test limitation. At December 31, 2002, we estimated, using a wellhead price of $4.35 per MCF, that our capitalized costs did not exceed the ceiling test limitation.

In calculating the ceiling test at December 31, 2001, we estimated, using a wellhead price of $2.38 per MCF, that our capitalized costs exceeded the ceiling limitation. As a result, in the fourth quarter of 2001, a $42.0 million impairment charge to write down our gas exploration and production assets was recorded. This charge was recorded in depreciation, depletion and amortization on the Consolidated Statement of Income. KeySpan's share of the impairment charge was $26.2 million after-tax, or $0.19 per share.

Natural gas prices continue to be volatile and the risk that a write down to the full cost pool increases when, among other things, natural gas prices are depressed, there are significant downward revisions in our estimated proved reserves or we have unsuccessful drilling results.

Houston Exploration capitalizes interest related to its unevaluated natural gas and oil properties, as well as some properties under development which are not currently being amortized. For years ended December 31, 2003, 2002 and 2001, capitalized interest was $7.3 million, $8.0 million and $12.0 million, respectively.

G. Goodwill and Other Intangible Assets

The balance of goodwill and other intangible assets was $1.8 billion at December 31, 2003 and 2002, representing primarily the excess of acquisition cost over the fair value of net assets acquired. Goodwill and other intangible assets reflect the Eastern and ENI acquisitions, the KeySpan/LILCO transaction, as well as acquisitions of energy-related service companies and also relates to certain ownership interests of 50% or less in energy-related investments in Northern Ireland which are accounted for under the equity method.

The table below summarizes the goodwill and other intangible assets balance for each segment at December 31, 2003 and 2002:

(In Thousands of Dollars)	Year Ended December 31,	
Operating Segment	2003	2002
Gas Distribution	$1,436,917	$1,436,917
Energy Services	172,874	148,596
Energy Investments and other	199,921	210,712
	$1,809,712	$1,796,225

The increase in goodwill related to the Energy Services segment primarily reflects the acquisition of Bard, Rao + Athanas Consulting Engineers, LLC. ("BR+A"), a Boston, Massachusetts company engaged in the business of providing engineering services relating to heating, ventilation, and air conditioning systems. The purchase price was approximately $35 million, plus up to $14.7 million in contingent consideration depending on the financial performance of BR+A over the five-year period following the closing of the acquisition. We have recorded goodwill of approximately $26 million and intangible assets of approximately $2 million associated with this transaction. The intangible assets, which relate primarily to a portion of the backlog purchased, as well as to non-compete agreements entered into with all of the former owners of BR+A, will be amortized over two and three years, respectively.

The decrease in goodwill related to Energy Investments and other primarily reflects the sale of our 24.5% interest in Phoenix Natural Gas Limited, located in Northern Ireland, and the related write-off of the goodwill associated with this investment.

On January 1, 2002, KeySpan adopted SFAS 142 "Goodwill and Other Intangible Assets". Under SFAS 142, among other things, goodwill is no longer required to be amortized and is to be tested for impairment at least annually. The initial impairment test was to be performed within six months of adopting SFAS 142 using a discounted cash flow method, compared to a undiscounted cash flow method allowed under a previous standard. Any amounts impaired using data as of January 1, 2002, was to be recorded as a "Cumulative Effect of an Accounting Change." Any amounts impaired using data after the initial adoption date will be recorded as an operating expense. During the second quarter of 2002, we completed our initial impairment analysis for all the reporting units and determined that no consolidated impairment existed. In the fourth quarter of 2002, KeySpan updated its review of the carrying value of goodwill compared to the fair value of the assets by reporting unit and determined that no impairment existed.

In the fourth quarter of 2003, KeySpan updated its review of the carrying value of goodwill associated with the Energy Services segment. KeySpan employed a combination of two methodologies in determining the fair value for its investment in the Energy Services segment, a market valuation approach and an income valuation approach. A third party specialist was engaged to assist with the valuation and evaluate the reasonableness of key assumptions employed. Under the market valuation approach, KeySpan compared relevant financial information relating to the companies included in the Energy Services segment to the corresponding financial information for a peer group of companies in the specialty trade-contracting sector of the construction industry. Under the income valuation approach, the fair value of a firm is obtained by discounting the sum of (i) the expected future cash flows to a firm; and (ii) the terminal value of a firm. As a result of our valuation, management has determined that the fair value of the assets adequately exceeds their carrying value and no impairment charge was necessary.

As required by SFAS 142, below is a reconciliation of reported earnings available for common stockholders for the years ended December 31, 2003, 2002 and 2001 and pro-forma net income, for the same periods, adjusted for the discontinuance of goodwill amortization.

	Year Ended December 31,		
(In Thousands of Dollars, Except for Per Share Amounts)	2003	2002	2001
Earnings for common stockholders	$ 380,886	$ 371,935	$ 218,350
Add back: goodwill amortization*	-	-	49,550
Adjusted net income	$ 380,886	$ 371,935	$ 267,900
Basic earnings per share	$ 2.41	$ 2.63	$ 1.58
Add back: goodwill amortization	-	-	0.36
Adjusted basic earnings per share	$ 2.41	$ 2.63	$ 1.94
Diluted earnings per share	$ 2.39	$ 2.61	$ 1.56
Add back: goodwill amortization	-	-	0.36
Adjusted diluted earnings per share	$ 2.39	$ 2.61	$ 1.92

* Excludes the write-off of $12.4 million of goodwill in 2001 associated with the Roy Kay Operations.

For the twelve months ended December 31, 2001, goodwill amortization was recorded in each segment as follows: Gas Distribution $35.6 million; Energy Services $8.2 million; and Energy Investments and other $5.8 million.

Prior to implementation of SFAS 142, goodwill was reviewed for impairment under SFAS 121 "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of." Under SFAS 121, the carrying value of goodwill was reviewed if the facts and circumstances, such as significant declines in sales, earnings or cash flows, or material adverse changes in the business climate, suggested it might be impaired. If this review indicated that goodwill was not recoverable, as determined based upon the estimated undiscounted cash flows of the entity acquired, impairment was measured by comparing the carrying value of the investment in such entity to its fair value. Fair value was determined based on quoted market values, appraisals, or discounted cash flows. For the year ended December 31, 2001, we reviewed the facts and circumstances for the entities carrying goodwill and as a result of the above procedures, wrote off $12.4 million associated with the Roy Kay Companies upon determination that the asset was not recoverable. (See Note 10, "Roy Kay Operations" for additional information.)

H. Hedging and Derivative Financial Instruments

From time to time, we employ derivative instruments to hedge a portion of our exposure to commodity price risk and interest rate risk, as well as to hedge cash flow variability associated with a portion of our peak electric energy sales. Whenever hedge positions are in effect, we are exposed to credit risk in the event of nonperformance by counter-parties to derivative contracts, as well as nonperformance by the counter-parties of the transactions against which they are hedged. We believe that the credit risk related to the futures, options and swap instruments is no greater than that associated with the primary commodity contracts which they hedge. Our derivative instruments do not qualify as energy trading contracts as defined by current accounting literature.

Financially-Settled Commodity Derivative Instruments: We employ derivative financial instruments, such as futures, options and swaps, for the purpose of hedging the cash flow variability associated with forecasted purchases and sales of various energy-related commodities. All such derivative instruments are accounted for pursuant to the requirements of SFAS 133 "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS 149, "Amendment of Statement 133 Derivative Instruments and Hedging Activities" (collectively, "SFAS 133"). With respect to those commodity derivative instruments that are designated and accounted for as cash flow hedges, the effective portion of periodic changes in the fair market value of cash flow hedges is recorded as other comprehensive income on the Consolidated Balance Sheet, while the ineffective portion of such changes in fair value is recognized in earnings. Unrealized gains and losses (on such cash flow hedges) that are recorded as other comprehensive income are subsequently reclassified into earnings concurrent when hedged transactions impact earnings. With respect to those commodity derivative instruments that are not designated as hedging instruments, such derivatives are accounted for on the Consolidated Balance Sheet at fair value, with all changes in fair value reported in earnings.

Firm Gas Sales Derivatives Instruments – Regulated Utilities: We utilize derivative financial instruments to reduce cash flow variability associated with the purchase price for a portion of our future natural gas purchases. Our strategy is to minimize fluctuations in firm gas sales prices to our regulated firm gas sales customers in our New York and New England service territories. Since these derivative instruments are being employed to support our gas sales prices to regulated firm gas sales customers, the accounting for these derivative instruments is subject to SFAS 71. Therefore, changes in the market value of these derivatives are recorded as regulatory assets or regulatory liabilities on our Consolidated Balance Sheet. Gains or losses on the settlement of these contracts are initially deferred and then refunded to or collected from our firm gas sales customers during the appropriate winter heating season consistent with regulatory requirements.

Physically-Settled Commodity Derivative Instruments: Upon implementation of Derivative Implementation Group ("DIG") Issue C16 on April 1, 2002, certain of our contracts for the physical purchase of natural gas were assessed as no longer being exempt from the requirements of SFAS 133 as normal purchases. As such, these contracts are recorded on the Consolidated Balance Sheet at fair market value. However, since such contracts were executed for the purchases of natural gas that is sold to regulated firm gas sales customers, and pursuant to the requirements of SFAS 71, changes in the fair market value of these contracts are recorded as a regulatory asset or regulatory liability on the Consolidated Balance Sheet.

Weather Derivatives: The utility tariffs associated with our New England gas distribution operations do not contain a weather normalization adjustment. As a result, fluctuations from normal weather may have a significant positive or negative effect on the results of these operations. To mitigate the effect of fluctuations from normal weather on our financial position and cash flows, we may enter into derivative instruments from time to time. Based on the terms of the contracts, we account for these instruments pursuant to the requirements of Emerging Issues Task Force ("EITF") 99-2 "Accounting for Weather Derivatives." In this regard, we account for weather derivatives using the "intrinsic value method" as set forth in such guidance.

Interest Rate Derivative Instruments: We continually assess the cost relationship between fixed and variable rate debt. Consistent with our objective to minimize our cost of capital, we periodically enter into hedging transactions that effectively convert the terms of underlying debt obligations from fixed to variable or variable to fixed. Payments made or received on these derivative contracts are recognized as an adjustment to interest expense as incurred. Hedging transactions that effectively convert the terms of underlying debt obligations from fixed to variable are designated and accounted for as fair-value hedges pursuant to the requirements of SFAS 133. Hedging transactions that effectively convert the terms of underlying debt obligations from variable to fixed are considered cash flow hedges.

I. Equity Investments

Certain subsidiaries own as their principal assets, investments (including goodwill), representing ownership interests of 50% or less in energy-related businesses that are accounted for under the equity method. None of these investments are publicly traded.

J. Income and Excise Tax

In accordance with SFAS 109, "Accounting for Income Taxes" and applicable rate regulation, certain of our regulated subsidiaries record a regulatory asset for the net cumulative effect of providing deferred income taxes on all differences between the financial statement carrying amounts of existing assets and liabilities, and their respective tax basis. Investment tax credits, which were available prior to the Tax Reform Act of 1986, were deferred and generally amortized as a reduction of income tax over the estimated lives of the related property.

We report our collections and payments of excise taxes on a gross basis. Gas distribution revenues include the collection of excise taxes, while operating taxes include the related expense. For the years ended December 31, 2003, 2002 and 2001, excise taxes collected and paid were $90.5 million, $83.1 million, $119.1 million, respectively.

K. Subsidiary Common Stock Issuances to Third Parties

We follow an accounting policy of income statement recognition for parent company gains or losses from issuances of common stock by subsidiaries to unaffiliated third parties.

L. Foreign Currency Translation

We follow the principles of SFAS 52, "Foreign Currency Translation," for recording our investments in foreign affiliates. Under this statement, all elements of the financial statements are translated by using a current exchange rate. Translation adjustments result from changes in exchange rates from one reporting period to another. At December 31, 2003 and 2002, the foreign currency translation adjustment was included on the Consolidated Balance Sheet. The functional currency for our foreign affiliates is their local currency.

M. Earnings Per Share

Basic earnings per share ("EPS") is calculated by dividing earnings for common stock by the weighted average number of shares of common stock outstanding during the period. No dilution for any potentially dilutive securities is included. Diluted EPS assumes the conversion of all potentially dilutive securities and is calculated by dividing earnings for common stock, as adjusted, by the sum of the weighted average number of shares of common stock outstanding plus all potentially dilutive securities.

At December 31, 2003 we have approximately 2 million options outstanding to purchase KeySpan common stock that were not used in the calculation of diluted EPS since the exercise price associated with these options was greater than the average per share market price of KeySpan's common stock. Further, we have 85,676 shares of convertible preferred stock outstanding that can be converted into 221,153 shares of common stock. These shares were not included in the calculation of diluted EPS for the year ending December 31, 2001 since to do so would have been anti-dilutive.

Under the requirements of SFAS 128, "Earnings Per Share" our basic and diluted EPS are as follows:

(In Thousands of Dollars, Except Per Share Amounts)	Year Ended December 31, 2003	2002	2001
Earnings for common stock	$ 380,886	$ 371,935	$ 218,350
Houston Exploration dilution	(269)	(471)	(1,116)
Preferred stock dividend	514	531	-
Earnings for common stock - adjusted	$ 381,131	$ 371,995	$ 217,234
Weighted average shares outstanding (000)	158,256	141,263	138,214
Add dilutive securities:			
Options	755	809	1,007
Convertible preferred stock	221	228	-
Total weighted average shares outstanding - assuming dilution	159,232	142,300	139,221
Basic earnings per share	$ 2.41	$ 2.63	$ 1.58
Diluted earnings per share	$ 2.39	$ 2.61	$ 1.56

N. Stock Options and Other Stock Based Compensation

We issue stock options to all KeySpan officers and certain other management employees as approved by the Board of Directors. These options generally vest over a three-to-five year period and have exercise periods between 5-10 years. Up to approximately 21 million shares have been authorized for the issuance of options and approximately 7.0 million of these shares were remaining at December 31, 2003. Moreover, under a separate plan, Houston Exploration has issued and outstanding approximately 2.5 million stock options to key Houston Exploration employees. KeySpan and Houston Exploration have adopted the prospective method of transition in accordance with SFAS 148 "Accounting for Stock-Based Compensation – Transition and Disclosure." Accordingly, compensation expense has been recognized by employing the fair value recognition provisions of SFAS 123 "Accounting for Stock-Based Compensation" for grants awarded after January 1, 2003.

KeySpan and Houston Exploration continue to apply APB Opinion 25, “Accounting for Stock Issued to Employees,” and related Interpretations in accounting for grants awarded prior to January 1, 2003. Accordingly, no compensation cost has been recognized for these fixed stock option plans in the Consolidated Financial Statements since the exercise prices and market values were equal on the grant dates. Had compensation cost for these plans been determined based on the fair value at the grant dates for awards under the plans consistent with SFAS 123, our net income and earnings per share would have decreased to the pro-forma amounts indicated below:

	Year Ended December 31,		
(In Thousands of Dollars, Except Per Share Amounts)	2003	2002	2001
Earnings available for common stock:			
As reported	$ 380,886	$ 371,935	$ 218,350
Add: recorded stock-based compensation expense, net of tax	3,650	221	261
Deduct: total stock-based compensation expense, net of tax	(9,358)	(7,547)	(8,459)
Pro-forma earnings	$ 375,178	$ 364,609	$ 210,152
Earnings per share:			
Basic - as reported	$ 2.41	$ 2.63	$ 1.58
Basic - pro-forma	$ 2.37	$ 2.58	$ 1.52
Diluted - as reported	$ 2.39	$ 2.61	$ 1.56
Diluted - pro-forma	$ 2.36	$ 2.56	$ 1.50

All grants are estimated on the date of the grant using the Black-Scholes option-pricing model. The following table presents the weighted average fair value, exercise price and assumptions used for the periods indicated:

	Year Ended December 31,		
	2003	2002	2001
Fair value of grants issued	$ 4.26	$ 3.42	$ 5.29
Dividend yield	5.49%	5.36%	4.91%
Expected volatility	24.26%	22.47%	29.04%
Risk free rate	3.16%	4.94%	5.13%
Expected lives	6 years	10 years	10 years
Exercise price	$ 32.40	$ 32.66	$ 39.50

A summary of the status of our fixed stock option plans and changes is presented below for the periods indicated:

	Year Ended December 31,					
	2003		2002		2001	
Fixed Options	Shares	Weighted Exercise Price	Shares	Weighted Exercise Price	Shares	Weighted Exercise Price
Outstanding at beginning of period	9,524,900	$ 30.74	7,796,162	$ 29.67	6,456,627	$ 25.61
Granted during the year	1,650,450	$ 32.40	2,796,310	$ 32.66	2,285,350	$ 39.50
Exercised	(664,902)	$ 23.64	(506,794)	$ 24.42	(809,983)	$ 25.15
Forfeited	(189,705)	$ 34.63	(560,778)	$ 30.99	(135,832)	$ 29.19
Outstanding at end of period	10,320,743	$ 31.39	9,524,900	$ 30.74	7,796,162	$ 29.67
Exercisable at end of period	5,365,545	$ 28.76	4,105,999	$ 27.69	2,996,771	$ 24.86

Remaining Contractual Life	Options Outstanding at December 31, 2003	Weighted Average Exercise Price	Range of Exercise Price	Options Exercisable at December 31, 2003	Weighted Average Exercise Price	Range of Exercise Price
2 years	30,138	$ 25.98	$14.86 - 27.00	30,138	$ 25.98	$14.86 - 27.00
3 years	221,086	$ 30.43	$20.57 - 30.50	221,086	$ 30.43	$20.57 - 30.50
4 years	301,410	$ 32.56	$19.15 - 32.63	301,410	$ 32.56	$19.15 - 32.63
5 years	1,359,727	$ 27.86	$24.73 - 29.38	1,359,727	$ 27.86	$24.73 - 29.38
6 years	652,344	$ 26.97	$21.99 - 27.06	652,344	$ 26.97	$21.99 - 27.06
7 years	1,567,924	$ 22.79	$22.50 - 32.76	1,546,262	$ 22.64	$22.50 - 32.76
8 years	2,012,038	$ 39.50	$39.50	805,553	$ 39.50	$39.50
9 years	2,565,404	$ 32.66	$32.66	449,025	$ 32.66	$32.66
10 years	1,610,672	$ 32.40	$32.40	-	$ 32.40	$32.40
	10,320,743			5,365,545		

In early 2003, KeySpan's Board of Directors approved a modification to the Long-Term Incentive Compensation Plan design and its application to officers of KeySpan. Long-term incentive compensation for officers consist of 50% stock options and 50% performance shares. Performance shares will be awarded based upon the attainment of overall corporate performance goals and will better align incentive compensation with overall corporate performance. During 2002, and in prior years, the majority of long-term incentive compensation awards were stock option grants with a limited amount of restricted stock award grants.

O. Recent Accounting Pronouncements

In January 2003, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 46 ("FIN 46"), "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51" which was revised in December 2003. 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 was effective 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 original provisions of FIN 46 were to be applied for the first interim or annual period beginning after June 15, 2003. In October, the FASB delayed implementation of FIN 46 until the fourth quarter 2003 for certain variable interest entities. We currently have an arrangement with a variable interest entity through which we lease a portion of the Ravenswood facility. As required by FIN 46, this variable entity was consolidated at December 31, 2003. (See Note 7 "Contractual Obligations, Financial Guarantees and Contingencies – Variable Interest Entity" for a detailed description of this leasing arrangement.)

In April 2003, the FASB issued SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." This Statement amends and clarifies financial accounting and reporting for derivative instruments, including certain instruments embedded in other contracts and for hedging activities under Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities." This Statement: (i) clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative; (ii) clarifies when a derivative contains a financing component; (iii) amends the definition of an underlying; and (iv) amends certain other existing pronouncements. The implementation of this Statement will not have a significant impact on our results of operations, financial condition or cash flows since our derivative instruments that meet the definition of a derivative and qualify for hedge accounting treatment will continue to do so. The Statement was effective for contracts entered into or modified after June 30, 2003.

In May 2003, the FASB issued SFAS 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." This Statement establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify certain financial instruments as a liability (or an asset in some circumstances) when there is an obligation to redeem the issuer's shares and either requires or may require satisfaction of the obligation by transferring assets, or satisfy the obligation by issuing additional equity shares subject to certain criteria. This Statement was effective for financial instruments entered into or modified after May 31, 2003, and otherwise was effective at the beginning of the first interim period beginning after June 15, 2003. It is to be implemented by reporting the cumulative effect of a change in an accounting principle for financial instruments created before the issuance date of the Statement and still existing at the beginning of the interim period of adoption. The implementation of this Statement did not have an impact on our results of operations, financial condition or cash flows.

In July 2003, the FASB concluded its discussions on EITF 03-11 "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 *Accounting for Derivative Instruments and Hedging Activities* and Not Held for Trading Purposes as Defined in EITF Issue No. 02-3 *Issues Involved in Accounting for Derivative Contracts held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.*" The Task Force reached a consensus that determining whether realized gains or losses on physically settled derivative contracts not "held for trading purposes" should be reported in the income statement on a gross or net basis is a matter of judgment that depends on the relevant facts and circumstances. KeySpan reports realized gains or losses on its derivative instruments that hedge the cash flow variability associated with the forecasted sales of natural gas and electricity in its reported revenues at time of their settlement. Realized gains or losses on derivative instruments that hedge the cash flow variability associated with the forecasted purchase of natural gas or fuel oil are reported in operating expense. We believe that this EITF does not have a significant impact on our results of operations, financial condition or cash flows. This Statement was effective October 1, 2003.

In December 2003, the FASB issued SFAS 132 (revised 2003) "Employers' Disclosures about Pensions and Other Postretirement Benefits." This Statement revises employers' disclosures about pension and other postretirement benefit plans. This Statement retains the disclosure requirements contained in FASB Statement 132 "Employers' Disclosures about Pensions and Other Postretirement Benefits", which it replaces. It requires additional disclosures to those in the original Statement 132 about assets, obligations, cash flows, and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. KeySpan has implemented all the requirements of this Statement in Footnote 4 "Postretirement Benefits."

P. Impact of Cumulative Effect of Change in Accounting Principles

KeySpan has an arrangement with a variable interest entity through which it leases a portion of the 2,200-megawatt Ravenswood electric generation facility. On December 31, 2003, KeySpan adopted FIN 46. This pronouncement required KeySpan to consolidate its variable interest entity, which had a fair market value of a $425 million at the inception of the lease, June 1999. As a result, KeySpan recorded a $37.6 million after-tax charge, or $0.23 per share, change in accounting principle on the Consolidated Statement of Income, representing approximately four and a half years of depreciation. (See Note 7, "Contractual Obligations, Financial Guarantees and Contingencies – Variable Interest Entity" for a detailed description of the impact of the adoption of this standard.)

On January 1, 2003, KeySpan adopted SFAS 143, "Accounting for Asset Retirement Obligations." SFAS 143 requires an entity to record a liability and corresponding asset representing the present value of legal obligations associated with the retirement of tangible, long-lived assets. The cumulative effect of SFAS 143 and the change in accounting principle was a benefit to net income of $0.2 million, after-tax. (See Note 7, "Contractual Obligations, Financial Guarantees and Contingencies – Asset Retirement Obligation" for further details.)

Under Accounting Principle Board Opinion No. 20 ("APB 20"), the pro-forma impact of the retroactive application resulting from the adoption of a change in accounting principle is to be disclosed as follows:

(*In Thousands of Dollars, Except Per Share Amounts*)	Year Ended December 31, 2003	2002	2001
Earnings for common stock	$ 380,886	$ 371,935	$ 218,350
Add back: Cumulative effect of a change in accounting principle	37,451	-	-
Earnings for common stock before cumulative effect of a change in accounting principle:			
As reported	418,337	371,935	218,350
Less: SFAS 143 Accretion expense, net of taxes	-	(1,135)	(1,067)
Less:FIN 46 Depreciation expense, net of taxes	(9,538)	(8,024)	(8,024)
Add: SFAS 143 Costs of removal expense, net of taxes	-	471	471
Pro-forma earnings	$ 408,799	$ 363,247	$ 209,730
Earnings per share before cumulative change in accounting principle:			
Basic - as reported	$ 2.64	$ 2.63	$ 1.58
Basic - pro-forma	$ 2.58	$ 2.57	$ 1.52
Diluted - as reported	$ 2.62	$ 2.61	$ 1.56
Diluted - pro-forma	$ 2.57	$ 2.55	$ 1.51
Earnings per share for common stock:			
Basic - as reported	$ 2.41	$ 2.63	$ 1.58
Basic - pro-forma	$ 2.58	$ 2.57	$ 1.52
Diluted - as reported	$ 2.39	$ 2.61	$ 1.56
Diluted - pro-forma	$ 2.57	$ 2.55	$ 1.51

Q. Accumulated Other Comprehensive Income

As required by SFAS 130, "Reporting Comprehensive Income", the components of accumulated other comprehensive income are as follows:

(*In Thousands of Dollars*)	**Year Ended December 31, 2003**	2002
Foreign currency translation adjustments	$ 26,523	$ (2,173)
Unrealized (losses) on marketable securities	(7,530)	(16,012)
Premium on derivative instrument	(3,437)	-
Accrued unfunded pension obligation	(60,650)	(69,031)
Unrealized (losses) on derivative financial instruments	(23,546)	(21,207)
Accumulated other comprehensive income	$ (68,640)	$ (108,423)

Note 2. Business Segments

We have four reportable segments: Gas Distribution, Electric Services, Energy Services and Energy Investments.

The Gas Distribution segment consists of our six gas distribution subsidiaries. KEDNY provides gas distribution services to customers in the New York City Boroughs of Brooklyn, Staten Island and a portion of the Borough of Queens. KEDLI provides gas distribution services to customers in the Long Island counties of Nassau and Suffolk and the Rockaway Peninsula of Queens County. The remaining gas distribution subsidiaries, collectively doing business as KEDNE, provide gas distribution service to customers in Massachusetts and New Hampshire.

The Electric Services segment consists of subsidiaries that: operate the electric transmission and distribution system owned by LIPA; own and provide capacity to and produce energy for LIPA from our generating facilities located on Long Island; and manage fuel supplies for LIPA to fuel our Long Island generating facilities. These services are provided in accordance with long-term service contracts having remaining terms that range from three to eleven years and Power Purchase agreements for 25 years. The Electric Services segment also includes subsidiaries that own, lease and operate the 2,200 megawatt Ravenswood electric generation facility located in Queens, New York. All of the energy, capacity and ancillary services related to the Ravenswood facility is sold to the NYISO energy markets. KeySpan is currently analyzing proposals from interested investors to participate in a leveraged lease financing of a new 250 MW combined cycle electric generating facility located at the existing Ravenswood facility site. (See Note 15, "Subsequent Events" for further details.)

The Energy Services segment includes companies that provide energy-related and a minimal amount of fiber optic services to customers primarily located within the Northeastern United States, with concentrations in the New York City metropolitan area, including New Jersey and Connecticut, as well as Rhode Island, Pennsylvania, Massachusetts and New Hampshire, through the following lines of business: (i) Home Energy Services, which provides residential customers with service and maintenance of energy systems and appliances, as well as the retail marketing of electricity to commercial customers; and (ii) Business Solutions, which provides plumbing, heating, ventilation, air conditioning and mechanical services, as well as operation and maintenance, design, engineering and consulting services to commercial and industrial customers.

In 2003, KeySpan Services, Inc. and its wholly-owned subsidiary Paulus, Sokolowski, and Sartor, LLC. acquired Bard, Rao + Athanas Consulting Engineers, LLC. ("BR+A"), a Boston, Massachusetts company engaged in the business of providing engineering services relating to heating, ventilation, and air conditioning systems. The purchase price was approximately $35 million, plus up to $14.7 million in contingent consideration depending on the financial performance of BR+A over the five-year period following the closing of the acquisition. We have recorded goodwill of $26 million and intangible assets of $2 million associated with this transaction. The intangible assets, which relate primarily to a portion of the backlog purchased, as well as to non-compete agreements entered into with all of the former owners of BR+A, will be amortized over two and three years, respectively. In 2003, KeySpan's gas and electric marketing subsidiary, KeySpan Energy Services Inc., assigned the majority of its retail natural gas customers, consisting mostly of residential and small commercial customers, to ECONnergy Energy Co., Inc. ("ECONnergy"). KeySpan Energy Services will continue its electric marketing activities.

The Energy Investments segment consists of our gas exploration and production investments, as well as certain other domestic and international energy-related investments. Our gas exploration and production subsidiaries are engaged in gas and oil exploration and production, and the development and acquisition of domestic natural gas and oil properties. These investments consist of our 55% equity interest in The Houston Exploration Company ("Houston Exploration"), an independent natural gas and oil exploration company, as well as our wholly-owned subsidiary KeySpan Exploration and Production, LLC, our wholly owned subsidiary engaged in a joint venture with Houston Exploration. In February 2003, we reduced our ownership interest in Houston Exploration from 66% to approximately 55% following the repurchase, by Houston Exploration, of three million shares of common stock owned by KeySpan. We realized net proceeds of $79 million in connection with this repurchase. KeySpan follows an accounting policy of income statement recognition for Parent company gains or losses from common stock transactions initiated by its subsidiaries. As a result, KeySpan realized a gain of $19 million on this transaction, which is reflected in other income and (deductions) on the Consolidated Statement of Income. Income taxes were not provided, since this transaction was structured as a return of capital.

In the fourth quarter of 2003, Houston Exploration acquired the entire Gulf of Mexico shallow-water asset base of Transworld Exploration and Production, Inc. for $149 million. The properties, which are 75% natural gas, have proven reserves of 92 billion cubic feet of natural gas equivalent. Current production from 11 fields is approximately 35 million cubic feet of natural gas equivalent per day. Houston Exploration funded the transaction from its bank revolving credit facility and with cash on hand at the time of closing.

Subsidiaries in this segment also hold a 20% equity interest in the Iroquois Gas Transmission System LP, a pipeline that transports Canadian gas supply to markets in the Northeastern United States; and a 50% interest in the Premier Transmission Pipeline Limited in Northern Ireland. These subsidiaries are accounted for under the equity method. Accordingly, equity income from these investments is reflected as a component of operating income in the Consolidated Statement of Income. In the fourth quarter of 2003, we completed the sale of our 24.5% interest in Phoenix Natural Gas Limited for $96 million and recorded a pre-tax gain of $24.7 million in other income and (deductions) on the Consolidated Statement of Income.

We also have investments in certain midstream natural gas assets in Western Canada through KeySpan Canada. These assets include 14 processing plants and associated gathering systems that can process approximately 1.5 BCFe of natural gas daily and provide associated natural gas liquids fractionation. In 2003, we sold a portion of our interest in KeySpan Canada through the establishment of an open-ended income fund trust ("KeySpan Facilities Income Fund" or the "Fund") organized under the laws of Alberta, Canada. The Fund acquired a 39.09% ownership interest in KeySpan Canada through an indirect subsidiary, and then issued 17 million trust units to the public through an initial public offering. Each trust unit represents a beneficial interest in the Fund and is registered on the Toronto Stock Exchange under the symbol KEY.UN. Additionally, we sold our 20% interest in Taylor NGL LP that owns and operates two extraction plants also in Canada to AltaGas Services, Inc. Net proceeds of $119.4 million from the two sales, plus proceeds of $45.7 million drawn under a new credit facility made available to KeySpan Canada, were used to pay down existing KeySpan Canada credit facilities of $160.4 million. A pre-tax loss of $30.3 million was recognized on the transactions and is included in other income and (deductions) on the Consolidated Statement of Income. These transactions produced a tax expense of $3.8 million as a result of certain United States partnership tax rules and resulted in an after-tax loss of $34.1 million. In February 2004, KeySpan entered into an agreement to sell an additional 36% of its interest in KeySpan Canada. (See Note 15 to the Consolidated Financial Statements, "Subsequent Events.")

The accounting policies of the segments are the same as those used for the preparation of the Consolidated Financial Statements. Our segments are strategic business units that are managed separately because of their different operating and regulatory environments. Operating results of our segments are evaluated by management on an operating income basis. Due to the July 2002 sale of Midland Enterprises LLC, an inland marine barge business, this subsidiary is reported as discontinued operations for 2002 and 2001. (See Note 9, "Discontinued Operations" for more information on the sale of Midland).

The reportable segment information below is shown excluding the operations of Midland:

(InThousands of Dollars)	Gas Distribution	Electric Services	Energy Services	Gas Exploration and Production	Other Investments	Eliminations	Consolidated
Year Ended December 31, 2003							
Unaffiliated revenue	4,161,272	1,503,086	641,432	501,255	108,116	-	6,915,161
Intersegment revenue	-	101	8,158	-	5,008	(13,267)	-
Depreciation, depletion and amortization	259,934	66,843	9,869	204,102	19,046	14,280	574,074
Sales of property	15,123	-	-	-	-	-	15,123
Income from equity investments	-	-	-	-	19,106	108	19,214
Operating income	574,254	268,977	(38,066)	197,209	41,345	(2,062)	1,041,657
Interest income	1,194	4,628	1,070	-	1,002	(2,235)	5,659
Interest charges	203,733	43,065	16,863	8,504	7,541	27,988	307,694
Total assets	8,444,071	2,473,076	445,534	1,530,875	915,383	817,845	14,626,784
Equity method investments	-	-	-	-	97,018	-	97,018
Construction expenditures	419,549	256,498	9,305	295,943	18,154	12,267	1,011,716

Eliminating items include intercompany interest income and expense, the elimination of certain intercompany accounts, as well as activities of our corporate and administrative subsidiaries.

Electric Services revenues from LIPA and the NYISO of $1.5 billion for the year ended December 31, 2003, represents approximately 22% of our consolidated revenues during that period.

(In Thousands of Dollars)	Gas Distribution	Electric Services	Energy Services	Gas Exploration and Production	Other Investments	Eliminations	Consolidated
Year Ended December 31, 2002							
Unaffiliated revenue	3,163,761	1,421,043	938,761	357,451	89,650	-	5,970,666
Intersegment revenue	-	100	-	-	1,128	(1,228)	-
Depreciation, depletion and amortization	237,186	61,377	9,522	176,925	14,573	15,030	514,613
Sales of property	903	1,479	-	-	2,348	-	4,730
Income from equity investments	-	-	-	-	13,992	104	14,096
Operating income	531,134	288,796	(11,935)	110,259	32,335	(8,507)	942,082
Interest income	2,020	1,834	1,248	-	238	(3,768)	1,572
Interest charges	215,140	57,589	19,386	7,303	6,858	(4,772)	301,504
Total assets	7,783,011	1,775,244	497,269	1,187,425	974,409	762,692	12,980,050
Equity method investments	-	-	-	-	130,815	-	130,815
Construction expenditures	412,433	348,147	11,648	241,477	31,243	16,074	1,061,022

Eliminating items include intercompany interest income and expense and the elimination of certain intercompany accounts as well as activities of our corporate and administrative subsidiaries.

Electric Services revenues from LIPA and the NYISO of $1.4 billion for the year ended December 31, 2002 represents approximately 24% of our consolidated revenues during that period.

(InThousands of Dollars)	Gas Distribution	Electric Services	Energy Services	Gas Exploration and Production	Other Investments	Eliminations	Consolidated
Year Ended December 31, 2001							
Unaffiliated revenue	3,613,551	1,421,079	1,100,167	400,031	98,287	-	6,633,115
Intersegment revenue	-	100	-	-	-	(100)	-
Depreciation, depletion and amortization	253,523	52,284	33,636	184,717	15,737	19,241	559,138
Income from equity investments	-	-	-	-	13,129	-	13,129
Operating income	481,393	269,721	(147,485)	159,661	19,122	31,366	813,778
Interest income	3,879	433	3,185	-	334	495	8,326
Interest charges	219,307	46,842	21,106	2,993	9,772	53,450	353,470
Total assets	6,994,140	1,677,710	550,891	951,135	797,294	818,436	11,789,606
Equity method investments	-	-	-	-	107,069	-	107,069
Construction expenditures	384,323	211,816	17,134	385,463	52,513	8,510	1,059,759

Eliminating items include intercompany interest income and expense and the elimination of certain intercompany accounts as well as activities of our corporate and administrative subsidiaries.

Electric Services revenues from LIPA and the NYISO of $1.4 billion for the year ended December 31, 2001 represents approximately 21% of our consolidated revenues during that period.

Note 3. Income Tax

KeySpan files a consolidated federal income tax return. A tax sharing agreement between the holding company and its subsidiaries provides for the allocation of a realized tax liability or benefit based upon separate return contributions of each subsidiary to the consolidated taxable income or loss in the consolidated income tax return. The subsidiaries record income tax payable or receivable from KeySpan resulting from the inclusion of their taxable income or loss in the consolidated return.

Income tax expense is reflected as follows in the Consolidated Statement of Income:

	Year Ended December 31,		
(In Thousands of Dollars)	2003	2002	2001
Current income tax	$ (104,355)	$ (24,212)	$ 101,738
Deferred income tax	381,666	267,691	108,955
Total income tax	$ 277,311	$ 243,479	$ 210,693

At December 31, the significant components of KeySpan's deferred tax assets and liabilities calculated under the provisions of SFAS No.109 "Accounting for Income Taxes" were as follows:

	December 31,	
(In Thousands of Dollars)	2003	2002
Reserves not currently deductible	$ 34,342	$ 38,275
New York corporation income tax	(56,188)	(13,997)
Property related differences	(1,049,237)	(818,116)
Regulatory tax asset	(16,532)	(18,690)
Property taxes	(98,089)	(52,339)
Other items - net	(87,947)	(12,146)
Net deferred tax liability	$ (1,273,651)	$ (877,013)

During the year ended December 31, 2002, an adjustment to deferred income taxes of $177.7 million was recorded to reflect a decrease in the tax basis of the assets acquired at the time of the KeySpan/LILCO combination. This adjustment resulted from a revised valuation study. Concurrent with this deferred tax adjustment, KeySpan reduced current income taxes payable by $183.2 million, resulting in a net $5.5 million income tax benefit. Currently, the Internal Revenue Service is auditing KeySpan's tax returns pertaining to the KeySpan/LILCO combination, as well as other return years. At this time, we cannot predict the outcome of the ongoing audit.

The federal income tax amounts included in the Statement of Income differ from the amounts which result from applying the statutory federal income tax rate to income before income tax.

The table below sets forth the reasons for such differences:

(In Thousands of Dollars)	Year Ended December 31, 2003	2002	2001
Computed at the statutory rate	$ 245,522	$ 224,290	$ 159,035
Adjustments related to:			
Tax credits	-	(1,026)	(1,100)
Removal costs	(6,592)	(4,787)	(1,470)
Accrual to return adjustment	549	(9,539)	2,354
Goodwill amortization	-	-	21,126
Minority interest in Houston Exploration	19,969	9,490	13,862
State income tax	28,462	42,125	26,418
Other items - net	(10,599)	(17,074)	(9,532)
Total income tax	$ 277,311	$ 243,479	$ 210,693
Effective income tax rate (1)	40%	38%	46%

(1) Reflects both federal as well as state income taxes.

Note 4. Postretirement Benefits

Pension Plans: The following information represents the consolidated results for our noncontributory defined benefit pension plans which cover substantially all employees. Benefits are based on years of service and compensation. Funding for pensions is in accordance with requirements of federal law and regulations. KEDLI and Boston Gas Company are subject to certain deferral accounting requirements mandated by the NYPSC and DTE, respectively for pension costs and other postretirement benefit costs.

Information pertaining to discontinued operations has been excluded from this presentation.

The calculation of net periodic pension cost is as follows:

(In Thousands of Dollars)	Year Ended December 31, 2003	2002	2001
Service cost, benefits earned during the period	$ 47,531	$ 42,423	$ 41,162
Interest cost on projected benefit obligation	138,270	132,424	128,481
Expected return on plan assets	(130,556)	(157,958)	(180,757)
Net amortization and deferral	66,949	(4,247)	(39,772)
Total pension (benefit) cost	$ 122,194	$ 12,642	$ (50,886)

The following table sets forth the pension plans' funded status at December 31, 2003 and December 31, 2002.

(In Thousands of Dollars)	Year Ended December 31, 2003	2002
Change in benefit obligation:		
Benefit obligation at beginning of period	$ (2,080,193)	$ (1,915,154)
Service cost	(47,531)	(42,423)
Interest cost	(138,270)	(132,424)
Amendments	(3,079)	(2,932)
Actuarial loss	(192,617)	(103,988)
Benefits paid	118,494	116,728
Benefit obligation at end of period	(2,343,196)	(2,080,193)
Change in plan assets:		
Fair value of plan assets at beginning of period	1,544,518	1,899,256
Actual return on plan assets	335,757	(347,270)
Employer contribution	93,458	109,260
Benefits paid	(118,494)	(116,728)
Fair value of plan assets at end of period	1,855,239	1,544,518
Funded status	(487,957)	(535,675)
Unrecognized net loss from past experience different from that assumed and from changes in assumptions	557,204	627,199
Unrecognized prior service cost	64,925	71,126
Unrecognized transition obligation	-	237
Net prepaid pension cost reflected on consolidated balance sheet	$ 134,172	$ 162,887

	Year Ended December 31, 2003	2002	2001
Assumptions:			
Obligation discount	6.25%	6.75%	7.00%
Asset return	8.50%	8.50%	8.50%
Average annual increase in compensation	4.00%	4.00%	4.00%

Unfunded Pension Obligation: At December 31, 2003 the accumulated benefit obligation was in excess of pension assets. As prescribed by SFAS 87 "Employers' Accounting for Pensions," KeySpan had a $244.4 million minimum liability at December 31, 2003, for this unfunded pension obligation. As permitted under current accounting guidelines, these accruals can be offset by a corresponding debit to a long-term asset up to the amount of accumulated unrecognized prior service costs. Any remaining amount is to be recorded in other comprehensive income on the Consolidated Balance Sheet.

Therefore, at year-end, we had a long-term asset in deferred charges other of $55.3 million, representing the amount of unrecognized prior service cost and a debit to other comprehensive income of $93.3 million, or $60.6 million after-tax. The remaining amount of $95.8 was recorded as a contractual receivable, representing the amount that would have been recovered from LIPA in accordance with our service agreements if the underlying assumptions giving rise to this minimum liability were realized and recorded as pension expense.

At December 31, 2003 the projected benefit obligation, accumulated benefit obligation and value of assets for plans with accumulated benefit obligations in excess of plan assets were $1.2 billion, $1.1 billion and $794 million.

At December 31, 2002, the accumulated benefit obligation was also in excess of pension assets. As a result, we had an additional minimum liability of $286.3 million, a long-term asset in deferred charges other of $61.5 million, and a debit to other comprehensive income of $106.2 million, or $69.0 million after-tax. The remaining amount of $118.6 was recorded as a contractual receivable from LIPA.

At December 31, 2002 the projected benefit obligation, accumulated benefit obligation and value of assets for plans with accumulated benefit obligations in plan assets were $1.1 billion, $948 million and $621 million, respectively.

At the end of the year, we will re-measure the accumulated benefit obligation and pension assets, and adjust the accrual and deferrals as appropriate.

Other Postretirement Benefits: The following information represents the consolidated results for our noncontributory defined benefit plans covering certain health care and life insurance benefits for retired employees. We have been funding a portion of future benefits over employees' active service lives through Voluntary Employee Beneficiary Association ("VEBA") trusts. Contributions to VEBA trusts are tax deductible, subject to limitations contained in the Internal Revenue Code.

Net periodic other postretirement benefit cost included the following components:

	Year Ended December 31,		
(In Thousands of Dollars)	2003	2002	2001
Service cost, benefits earned during the period	$ 18,825	$16,566	$20,339
Interest cost on accumulated postretirement benefit obligation	69,803	65,486	64,649
Expected return on plan assets	(27,530)	(36,839)	(42,822)
Net amortization and deferral	35,815	17,527	11,664
Other postretirement cost	$ 96,913	$62,740	$53,830

The following table sets forth the plans' funded status at December 31, 2003 and December 31, 2002.

(In Thousands of Dollars)	Year Ended December 31, 2003	2002
Change in benefit obligation:		
Benefit obligation at beginning of period	$(1,056,944)	$ (969,692)
Service cost	(18,825)	(16,566)
Interest cost	(69,803)	(65,486)
Plan participants' contributions	(1,757)	(1,587)
Amendments	35,458	57,984
Actuarial (loss)	(209,446)	(115,563)
Benefits paid	53,693	53,966
Benefit obligation at end of period	(1,267,624)	(1,056,944)
Change in plan assets:		
Fair value of plan assets at beginning of period	361,166	476,146
Actual return on plan assets	85,625	(82,950)
Employer contribution	43,578	20,349
Plan participants' contributions	1,757	1,587
Benefits paid	(53,693)	(53,966)
Fair value of plan assets at end of period	438,433	361,166
Funded status	(829,191)	(695,778)
Unrecognized net loss from past experience different from that assumed and from changes in assumptions	573,277	464,269
Unrecognized prior service cost	(89,034)	(60,104)
Accrued postretirement cost reflected on consolidated balance sheet	$ (344,948)	$ (291,613)

	Year Ended December 31, 2003	2002	2001
Assumptions:			
Obligation discount	6.25%	6.75%	7.00%
Asset return	8.50%	8.50%	8.50%
Average annual increase in compensation	4.00%	4.00%	4.00%

The measurement of plan liabilities also assumes a health care cost trend rate of 11% grading down to 5% over five years, and 5% thereafter. A 1% increase in the health care cost trend rate would have the effect of increasing the accumulated postretirement benefit obligation as of December 31, 2003 by $149.9 million and the net periodic health care expense by $12.3 million. A 1% decrease in the health care cost trend rate would have the effect of decreasing the accumulated postretirement benefit obligation as of December 31, 2003 by $131.8 million and the net periodic health care expense by $10.5 million.

At December 31, 2003, KeySpan had a contractual receivable from LIPA of $226.3 million representing the postretirement benefits associated with the electric business unit employees recorded in deferred charges other on the Consolidated Balance Sheet. LIPA has been reimbursing us for costs related to the postretirement benefits of the electric business unit employees in accordance with the LIPA Agreements.

KeySpan's retiree health benefit plan currently includes a prescription drug benefit that is provided to retired employees. In December 2003, new Medicare legislation (the Medicare Prescription Drug, Improvement and Modernization Act of 2003 – "the Medicare Act") was enacted that may ultimately affect KeySpan's obligations and expense related to retiree health benefits. Keyspan has elected to defer accounting for the effects of the Medicare Act, as permitted by FASB Staff Position 106-1 “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003”. Therefore, any measure of the accumulated postretirement benefit obligation or retiree benefit costs reflected in the accompanying notes do not reflect the effects of this new legislation. In consideration of this new law, KeySpan may need to amend certain benefit plans and, therefore, the impact of the Medicare Act on KeySpan’s financial condition and cash flows can not be determined with any degree of certainty at this time. Further, the FASB will be issuing specific guidance on the accounting for the subsidy arising under the Medicare Act and that guidance, when issued, could require KeySpan to change previously reported information.

Pension/Other Post Retirement Benefit Plan Assets: Keyspan’s weighted average asset allocations at December 31, 2003 and 2002, by asset category, for both the pension and other postretirement benefit plans are as follows:

	Pension		OPEB	
Asset Category	2003	2002	2003	2002
Equity securities	61%	54%	68%	60%
Debt securities	31%	30%	26%	28%
Cash and equivalents	2%	8%	2%	7%
Venture capital	6%	8%	4%	5%
Total	100%	100%	100%	100%

The long-term rate of return on assets (pre-tax) is assumed to be 8.5% which management believes is an appropriate long-term expected rate of return on assets based on our investment strategy, asset allocation mix and the historical performance of equity investments over long periods of time. The actual ten- year compound rate of return for our Plans is greater than 8.5%.

Our master trust investment allocation policy target for the assets of the pension and other postretirement benefit plans is 70% equity and 30% fixed income.

During 2003, KeySpan conducted an asset and liability study projecting asset returns and expected benefit payments over a ten-year period. Based on the results of the study, KeySpan has developed a multi-year funding strategy for its plans. We believe that it is reasonable to assume assets can achieve or outperform the assumed long-term rate of return with the target allocation as a result of historical out-performance of equity investments over long-term periods.

Cash Contributions: In 2004, KeySpan is expected to contribute approximately $89 million to its pension plans and approximately $58 million to its other postretirement benefit plans.

Defined Contribution Plan: KeySpan also offers both its union and management employees a defined contribution plan. Both the KeySpan Energy 401(k) Plan for Management Employees and the KeySpan Energy 401(k) Plan for Union Employees are available to all eligible employees. These Plans are defined contribution plans subject to Title I of the Employee Retirement Income Security Act of 1974 ("ERISA"). All eligible employees contributing to the Plan receive a certain employer matching contribution based on a percentage of the employee contribution, as well as a 10% discount on the KeySpan Common Stock Fund. The matching contributions are in KeySpan's common stock. For the years ended December 31, 2003, 2002 and 2001, we recorded an expense of $11.2 million, $11.2 million, and $11.0 million respectively.

Note 5. Capital Stock

Common Stock: Currently we have 450,000,000 shares of authorized common stock. In 1998, we initiated a program to repurchase a portion of our outstanding common stock on the open market. At December 31, 2003, we had 13.1 million shares, or approximately $378.5 million of treasury stock outstanding. We completed this repurchase plan in 1999 and have since utilized treasury stock to satisfy our common stock benefit plans. During 2003, we issued 3.3 million shares out of treasury for the dividend reinvestment feature of our Investor Program, the Employee Stock Discount Purchase Plan, the 401(k) Plan and Stock Option Plans.

On January 17, 2003, we issued 13.9 million shares of common stock in a public offering that generated net proceeds of approximately $473 million. All shares were offered by KeySpan pursuant to an effective shelf registration statement filed with the SEC.

Preferred Stock: We have the authority to issue 100,000,000 shares of preferred stock with the following classifications: 16,000,000 shares of preferred stock, par value $25 per share; 1,000,000 shares of preferred stock, par value $100 per share; and 83,000,000 shares of preferred stock, par value $.01 per share.

At December 31, 2003 we had 553,000 shares outstanding of 7.07% Preferred Stock Series B par value $100; 197,000 shares outstanding of 7.17% Preferred Stock Series C par value $100; and 85,676 shares outstanding of 6% Preferred Stock Series A par value $100, in the aggregate totaling $83.6 million.

In September 2003, the Boston Gas Company redeemed all 562,700 shares of its outstanding Variable Term Cumulative Preferred Stock, 6.42% Series A at its par value of $25 per share. The total payment was $14.3 million, which included $0.2 million of accumulated dividends. This preferred stock series had been reflected as Minority Interest on KeySpan's Consolidated Balance Sheet.

Note 6. Long-Term Debt

Notes Payable: KEDLI had $125 million of Medium-Term Notes at 6.90% due January 15, 2008, and $400 million of 7.875% Medium-Term Notes due February 1, 2010, outstanding at December 31, 2003, each of which is guaranteed by KeySpan.

Further, KeySpan had $2.36 billion of medium and long term notes outstanding at December 31, 2003 of which $1.65 billion of these notes are associated with the acquisition of Eastern and ENI. These notes were issued in three series as follows: $700 million, 7.25% Notes due 2005; $700 million, 7.625% Notes due 2010 and $250 million, 8.00% Notes due 2030. The remaining notes of $710 million have interest rates ranging from 6.15% to 9.75% and mature in 2005-2025.

In 2003, we issued $300 million of medium-term and long-term debt. The debt was issued in the following two series: (i) $150 million 4.65% Notes due 2013; and (ii) $150 million 5.875% Notes due 2033. The proceeds of this issuance were used to pay down outstanding commercial paper.

Also during 2003, KeySpan Canada, issued Cdn$125 million, or approximately US$93 million, long-term secured notes in a private placement to investors in Canada and the United States. The notes were issued in the following three series: (i) Cdn$20 million 5.42% senior secured notes due 2008; (ii) Cdn$52.5 million 5.79% senior secured notes due 2010; and (iii) Cdn$52.5 million 6.16% senior secured notes due 2013. The proceeds of the offering have been used to re-pay KeySpan Canada's credit facility.

In 2003 Houston Exploration finalized a private placement issuance of $175 million of 7.0%, senior subordinated notes due 2013. Interest payments began on December 15, 2003, and will be paid semi-annually thereafter. The notes will mature on June 15, 2013. Houston Exploration has the right to redeem the notes as of June 15, 2008, at a price equal to the issue price plus a specified redemption premium. Until June 15, 2006, Houston Exploration may also redeem up to 35% of the notes at a redemption price of 107% with proceeds from an equity offering. Houston Exploration incurred approximately $4.5 million of debt issuance costs on this private placement.

Houston Exploration used a portion of the net proceeds from the issuance to redeem all of its outstanding $100 million principal amount of 8.625% senior subordinated notes due 2008 at a price of 104.313% of par plus interest accrued to the redemption date. Debt redemption costs totaled approximately $5.9 million and is reflected in other income and (deductions) in the Consolidated Statement of Income. The remaining net proceeds from the offering were used to reduce debt amounts associated with Houston Exploration's bank revolving credit facility.

Gas Facilities Revenue Bonds: KEDNY can issue tax-exempt bonds through the New York State Energy Research and Development Authority. Whenever bonds are issued for new gas facilities projects, proceeds are deposited in trust and subsequently withdrawn to finance qualified expenditures. There are no sinking fund requirements on any of our Gas Facilities Revenue Bonds. At December 31, 2003, KEDNY had $648.5 million of Gas Facilities Revenue Bonds outstanding. The interest rate on the variable rate series due December 1, 2020 is reset weekly and ranged from 0.60% to 1.20% during the year ended December 31, 2003, at which time the rate was 1.10%.

Promissory Notes: In connection with the KeySpan/LILCO transaction, KeySpan and certain of its subsidiaries issued promissory notes to LIPA to support certain debt obligations assumed by LIPA. The remaining principal amount of promissory notes issued to LIPA was approximately $600 million at December 31, 2002. In 2003 we called approximately $447 million aggregate principal amount of such promissory notes at the applicable redemption prices plus accrued and unpaid interest through the dates of redemption. Therefore, at December 31, 2003, $155.4 million of these promissory notes remained outstanding. Under these promissory notes, KeySpan is required to obtain letters of credit to secure its payment obligations if its long-term debt is not rated at least in the "A" range by at least two nationally recognized statistical rating agencies. At December 31, 2003, KeySpan was in compliance with this requirement.

Interest savings associated with this redemption were $15.6 million after-tax, or $0.10 per share, in 2003. We applied the provisions of SFAS 145 "Rescission of FASB Statement No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" and recorded an expense of $18.2 million, reflecting redemption costs, as well as the write-off of previously deferred debt issuance costs. This expense has been recorded in other income and (deductions) in the Consolidated Statement of Income.

***MEDS Equity Units*:** At December 31, 2003, KeySpan had $460 million of MEDS Equity Units outstanding at 8.75% consisting of a three-year forward purchase contract for our common stock and a six-year note. The purchase contract commits us, three years from the date of issuance of the MEDS Equity Units, May 2005, to issue and the investors to purchase, a number of shares of our common stock based on a formula tied to the market price of our common stock at that time. The 8.75% coupon is composed of interest payments on the six-year note of 4.9% and premium payments on the three-year equity forward contract of 3.85%. These instruments have been recorded as long-term debt on the Consolidated Balance Sheet. Further, upon issuance of the MEDS Equity Units, we recorded a direct charge to retained earnings of $49.1 million, which represents the present value of the forward contract's premium payments.

There were eight million MEDS Equity units issued which are subject to conversion upon execution of the three-year forward purchase contract. The number of shares to be issued depends on the average closing price of our common stock over the 20 day trading period ending on the third trading day prior to May 16, 2005. If the average closing price over this time frame is less than or equal to $35.30 of KeySpan's common stock, 11.3 million shares will be issued. If the average closing price over this time frame is greater than or equal to $42.36, 9.4 million shares will be issued. The number of shares issued at a price between $35.30 and $42.36 will be between 9.4 million and 11.3 million based upon a sliding scale.

These securities are currently not considered convertible instruments for purposes of applying SFAS 128 "Earnings Per Share" calculations, unless or until such time as the market value of our common stock reaches a threshold appreciation price ($42.36 per share) that is higher than the current per share market value. Interest payments do, however, reduce net income and earnings per share.

The Emerging Issues Task Force of the FASB is considering proposals related to accounting for certain securities and financial instruments, including securities such as the Equity Units. The current proposals being considered include the method of accounting discussed above. Alternatively, other proposals being considered could result in the common shares issuable pursuant to the purchase contract to be deemed outstanding and included in the calculation of diluted earnings per share, and could result in periodic "mark to market" of the purchase contracts, causing periodic charges or credits to income. If this latter approach were adopted, our basic and diluted earnings per share could increase and decrease from quarter to quarter to reflect the lesser and greater number of shares issuable upon satisfaction of the contract, as well as charges or credits to income.

Industrial Development Revenue Bonds: In the fourth quarter of 2003, KeySpan closed on a financing arrangement pursuant to which $128 million tax-exempt bonds with a 5.25% coupon maturing in June 2027 were issued on its behalf. Fifty-three million dollars of these Industrial Development Revenue Bonds were issued through the Nassau County Industrial Development Authority for the construction of the Glenwood electric-generation peaking plant and the balance of $75 million was issued by the Suffolk County Industrial Development Authority for the Port Jefferson electric-generation peaking plant. Proceeds from the transaction were used to repay commercial paper used to finance the construction, installation and equipping of the two facilities. KeySpan has guaranteed all payment obligations of our subsidiaries with regard to these bonds.

First Mortgage Bonds: Colonial Gas Company, Essex Gas Company, ENI and their respective subsidiaries, have issued and outstanding approximately $153.2 million of first mortgage bonds. These bonds are secured by KEDNE gas utility property. The first mortgage bond indentures include, among other provisions, limitations on: (i) the issuance of long-term debt; (ii) engaging in additional lease obligations; and (iii) the payment of dividends from retained earnings.

Authority Financing Notes: Certain of our electric generation subsidiaries can issue tax-exempt bonds through the New York State Energy Research and Development Authority. At December 31, 2003, $41.1 million of Authority Financing Notes 1999 Series A Pollution Control Revenue Bonds due October 1, 2028 were outstanding. The interest rate on these notes is reset based on an auction procedure. The interest rate during 2003 ranged from 0.56% to 1.15%, through December 31, 2003, at which time the rate was 1.10%.

We also have outstanding $24.9 million variable rate 1997 Series A Electric Facilities Revenue Bonds due December 1, 2027. The interest rate on these bonds is reset weekly and ranged from 0.70 % to 1.21% from January 1, 2003 through December 31, 2003 at which time the rate was 1.08%.

Ravenswood Master Lease: We have an arrangement with a variable interest unaffiliated entity through which we lease a portion of the Ravenswood facility. We acquired the Ravenswood facility, in part, through the variable interest entity, from Consolidated Edison on June 18, 1999 for approximately $597 million. In order to reduce the initial cash requirements, we entered into a lease agreement (the "Master Lease") with a variable interest financing entity that acquired a portion of the facility, three steam generating units, directly from Consolidated Edison and leased it to a KeySpan subsidiary. The variable interest financing entity acquired the property for $425 million, financed with debt of $412.3 million (97% of capitalization) and equity of $12.7 million (3% of capitalization). Monthly lease payments are substantially equal to the monthly interest expense on the debt securities.

In December 2003, KeySpan implemented FASB Interpretation No. 46 ("FIN 46"), "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51." This Interpretation required us to, among other things, consolidate this variable interest entity and classify the Master Lease as $412.3 million long-term debt on the Consolidated Balance Sheet. Further, we recorded an asset on the Consolidated Balance Sheet for an amount substantially equal to the fair market value of the leased assets at the inception of the lease, less depreciation since that date. Under the terms of our credit facility the Master Lease has been considered debt in the ratio of debt-to-total capitalization since the inception of the lease and therefore, implementation of FIN 46 has no impact on our credit facility. (See Note 7 "Contractual Obligations, Financial Guarantees and Contingencies" for additional information regarding the leasing arrangement associated with the Master Lease Agreement and FIN 46 implementation issues.)

PUHCA Authorization: In the fourth quarter of 2003 KeySpan received authorization from the SEC, under PUCHA, to issue up to an additional $3 billion of securities through December 31, 2006. This authorization provides KeySpan with the necessary flexibility to finance future capital requirements over the next three years.

Commercial Paper and Revolving Credit Agreements: In June 2003, KeySpan renewed its $1.3 billion revolving credit facility, which was syndicated among sixteen banks. The credit facility supports KeySpan's commercial paper program, and consists of two separate credit facilities with different maturities but substantially similar terms and conditions: a $450 million facility that extends for 364 days, and a $850 million facility that is committed for three years. The fees for the facilities are subject to a ratings-based grid, with an annual fee that ranges from eight to twenty five basis points on the 364-day facility and ten to thirty basis points on the three-year facility. Both credit agreements allow for KeySpan to borrow using several different types of loans; specifically, Eurodollar loans, ABR loans, or competitively bid loans. Eurodollar loans are based on the Eurodollar rate plus a margin. ABR loans are based on the highest of the Prime Rate, the base CD rate plus 1%, or the Federal Funds Effective Rate plus 0.5%, plus a margin. Competitive bid loans are based on bid results requested by KeySpan from the lenders. The margins on both facilities are ratings based and range from zero basis points to 112.5 basis points. The margins are increased if outstanding loans are in excess of 33% of the total facility. In addition, the 364-day facility has a one-year term out option, which would cost an additional 0.25% if utilized. We do not anticipate borrowing against this facility; however, if the credit rating on our commercial paper program were to be downgraded, it may be necessary to do so.

The credit facility contains certain affirmative and negative operating covenants, including restrictions on KeySpan's ability to mortgage, pledge, encumber or otherwise subject its property to any lien and certain financial covenants that require us to, among other things, maintain a consolidated indebtedness to consolidated capitalization ratio of no more than 64%.

Under the terms of the credit facility, the calculation of KeySpan's debt-to-total capitalization ratio reflects 80% equity treatment for the MEDS Equity Units. At December 31, 2003, consolidated indebtedness, as calculated under the terms of the credit facility, was 58.2% of consolidated capitalization. Violation of this covenant could result in the termination of the credit facility and the required repayment of amounts borrowed thereunder, as well as possible cross defaults under other debt agreements.

The credit facility also requires that net cash proceeds from the sale of subsidiaries be applied to reduce consolidated indebtedness. Further, an acceleration of indebtedness of KeySpan or one of its subsidiaries for borrowed money in excess of $25 million in the aggregate, if not annulled within 30 days after written notice, would create an event of default under the Indenture, dated as of November 1, 2000, between KeySpan Corporation and the Chase Manhattan Bank, as Trustee. At December 31, 2003, KeySpan was in compliance with all covenants.

At December 31, 2003, we had cash and temporary cash investments of $205.8 million. During 2003, we repaid $433.8 million of commercial paper and, at December 31, 2003, $481.9 million of commercial paper was outstanding at a weighted average annualized interest rate of 1.2%. We had the ability to borrow up to an additional $818.1 million at December 31, 2003, under the commercial paper program.

Houston Exploration has a revolving credit facility with a commercial banking syndicate that provides Houston Exploration with a commitment of $300 million, which can be increased, at its option to a maximum of $350 million with prior approval from the banking syndicate. The credit facility is subject to borrowing base limitations, currently set at $300 million and is re-determined semi-annually. Up to $25 million of the borrowing base is available for the issuance of letters of credit. The new credit facility matures July 15, 2005, is unsecured and, with the exception of trade payables, ranks senior to all existing debt.

Under the Houston Exploration credit facility, interest on base rate loans is payable at a fluctuating rate, or base rate, equal to the sum of (a) the greater of the federal funds rate plus

0.50% or the bank's prime rate plus (b) a variable margin between 0% and 0.50%, depending on the amount of borrowings outstanding under the credit facility. Interest on fixed loans is payable at a fixed rate equal to the sum of (a) a quoted reserve adjusted LIBOR rate plus (b) a variable margin between 1.25% and 2.00%, depending on the amount of borrowings outstanding under the credit facility.

Financial covenants require Houston Exploration to, among other things, (i) maintain an interest coverage ratio of at least 3.00 to 1.00 of earnings before interest, taxes and depreciation ("EBITDA") to cash interest; (ii) maintain a total debt to EBITDA ratio of not more than 3.50 to 1.00; and (iii) hedge no more than 70% of natural gas production during any 12-month period. At December 31, 2003, Houston Exploration was in compliance with all financial covenants.

During 2003, Houston Exploration borrowed $239 million under its credit facility and repaid $264 million. At December 31, 2003, $127 million of borrowings remained outstanding at a weighted average annualized interest rate of 3.42%. Also, $0.4 million was committed under outstanding letters of credit obligations. At December 31, 2003, $172.6 million of borrowing capacity was available.

In 2003, KeySpan Canada replaced its two outstanding credit facilities with one new facility with three tranches that combined allowed KeySpan Canada to borrow up to approximately $125 million. At the time of the partial sale of KeySpan Canada, net proceeds from the sale of $119.4 million plus an additional $45.7 million drawn under the new credit facilities were used to pay down existing outstanding debt of $160.4 million. During the third quarter of 2003, KeySpan Canada issued Cdn$125 million, or approximately US$93 million, in long-term secured notes in a private placement, as previously mentioned. The proceeds of the offering were used to pay-down, in its entirety, outstanding borrowings under the credit facility. Further, one tranch of the credit facility was discontinued. At December 31, 2003, KeySpan Canada's credit facility has the following two tranches with the following maturities: (i) $37.5 million matures in 364 days: and (ii) $37.5 million matures in two years. During 2003, KeySpan Canada borrowed $71.5 million from its prior credit facilities and repaid $240.3 million. During the fourth quarter of 2003, KeySpan Canada borrowed $18.1 million under the new facility and at December 31, 2003 $56.9 million is available for future borrowing. KeySpan is not a guarantor of this facility.

Capital Leases: Our subsidiaries lease certain facilities and equipment under long-term leases, which expire on various dates through 2022. The weighted average interest rate on these obligations was 6.12%.

Debt Maturity: The following table reflects the maturity schedule for our debt repayment requirements, including capitalized leases and related maturities, at December 31, 2003:

(In Thousands of Dollars)	Long-Term Debt	Capital Leases	Total
Repayments:			
Year 1	$ 333	$ 1,138	$ 1,471
Year 2	1,302,333	1,096	1,303,429
Year 3	512,333	1,003	513,336
Year 4	333	1,063	1,396
Year 5	160,761	1,129	161,890
Thereafter	3,649,613	7,552	3,657,165
	$ 5,625,706	$ 12,981	$ 5,638,687

Note 7. Contractual Obligations, Financial Guarantees and Contingencies

Lease Obligations: Lease costs included in operation expense were $82.1 million in 2003 reflecting, primarily, the Master Lease and the lease of our Brooklyn headquarters of $29.3 million and $14.6 million, respectively. Lease costs also include leases for other buildings, office equipment, vehicles and power operated equipment. Lease costs for the year ended December 31, 2002 and 2001 were $71.1 million and $75.8 million, respectively. As previously mentioned, the Master Lease has been consolidated as required by FIN 46, and as a result, future lease payments will be reflected as interest expense on the Consolidated Statement of Income beginning January 1, 2004. The future minimum cash lease payments under various leases, excluding the Master Lease, all of which are operating leases, are $58.9 million per year over the next five years and $122.2 million, in the aggregate, for all years thereafter. (See discussion below for further information regarding the Master Lease.)

Variable Interest Entity*:* As mentioned, KeySpan has an arrangement with a variable interest entity through which we lease a portion of the Ravenswood facility. We acquired the Ravenswood facility, a 2,200-megawatt electric generating facility located in Queens, New York, in part, through the variable interest entity from Consolidated Edison on June 18, 1999 for approximately $597 million. In order to reduce the initial cash requirements, we entered into the Master Lease with a variable interest, unaffiliated financing entity that acquired a portion of the facility, or three steam generating units, directly from Consolidated Edison and leased it to our subsidiary. The variable interest unaffiliated financing entity acquired the property for $425 million, financed with debt of $412.3 million (97% of capitalization) and equity of $12.7 million (3% of capitalization). KeySpan has no ownership interests in the units or the variable interest entity. KeySpan has guaranteed all payment and performance obligations of our subsidiary under the Master Lease. Monthly lease payments substantially equal the monthly interest expense on such debt securities.

The initial term of the Master Lease expires on June 20, 2004 and may be extended until June 20, 2009. In June 2004, we have the right to: (i) either purchase the facility for the original acquisition cost of $425 million, plus the present value of the lease payments that would otherwise have been paid through June 2009; (ii) terminate the Master Lease and dispose of the facility; or (iii) otherwise extend the Master Lease to 2009. If the Master Lease is terminated in 2004, KeySpan has guaranteed an amount generally equal to 83% of the residual value of the original cost of the property, plus the present value of the lease payments that would have otherwise been paid through June 20, 2009. At this time, KeySpan intends to maintain a leasing arrangement for the foreseeable future. In June 2009, when the Master Lease terminates, we may purchase the facility in an amount equal to the original acquisition cost, subject to adjustment, or surrender the facility to the lessor. If we elect not to purchase the property, the Ravenswood facility will be sold by the lessor. We have guaranteed to the lessor 84% of the residual value of the original cost of the property.

In December 2003, KeySpan implemented FASB Interpretation No. 46 ("FIN 46"), "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51." This Interpretation required us to, among other things, consolidate this variable interest entity and classify the Master Lease as $412.3 million long-term debt on the Consolidated Balance Sheet based on our current status as primary beneficiary. Further, we recorded an asset on the Consolidated Balance Sheet for an amount substantially equal to the fair market value of the leased assets at the inception of the lease, less depreciation since that date, or approximately $388 million. As previously mentioned, under the terms of our credit facility the Master Lease has been considered debt in the ratio of debt-to-total capitalization since the inception of the lease and therefore, implementation of FIN 46 has no impact on our credit facility. In addition, we recorded a $37.6 million after-tax charge, or $0.23 per share, change in accounting principle on the Consolidated Statement of Income, representing approximately four and a half years of depreciation. Based upon expected average outstanding shares, we anticipate the incremental impact of the additional depreciation expense for 2004 to be approximately $0.05 per share. Yearly lease payments will be reflected as interest expense on the Consolidated Statement of Income beginning January 1, 2004. Future minimum lease payments are $30.8 per year over the next five years and $15.4 million for 2009.

If our subsidiary that leases the Ravenswood facility was not able to fulfill its payment obligations with respect to the Master Lease payments, then the maximum amount KeySpan would be exposed to under its current guarantees would be $425 million plus the present value of the remaining lease payments through June 20, 2009.

***Asset Retirement Obligations*:** On January 1, 2003, KeySpan adopted SFAS 143, "Accounting for Asset Retirement Obligations." SFAS 143 requires an entity to record a liability and corresponding asset representing the present value of legal obligations associated with the retirement of tangible, long-lived assets. At December 31, 2003, the present value of our future asset retirement obligation ("ARO") was approximately $92.4 million, primarily related to our investment in Houston Exploration. The cumulative effect of SFAS 143 and the change in accounting principle was a benefit to net income of $0.2 million, after-tax.

The following table describes on a pro-forma basis the asset retirement obligation associated with Houston Exploration as if SFAS 143 had been adopted on January 1, 2002.

(In Thousands of Dollars)	For the Year Ended December 31, 2003	2002
ARO Liability at January 1,	$ 57,197	$ 45,759
Additions from drilling	5,738	8,507
Additions from purchases	29,244	286
Deletions from abandonment	(160)	-
Changes resulting from timing	(3,330)	-
ARO accretion expense	3,668	2,645
ARO Liability at December 31,	$ 92,357	$ 57,197
Reflected on Consolidated Balance Sheet		
ARO Liability - Current	$ 7,703	N/A
ARO Liability - Long term	$ 84,654	N/A

KeySpan's largest asset base is its gas transmission and distribution system. A legal obligation exists due to certain safety requirements at final abandonment. In addition, a legal obligation may be construed to exist with respect to KeySpan's liquefied natural gas ("LNG") storage tanks due to clean up responsibilities upon cessation of use. However, mass assets such as storage, transmission and distribution assets are believed to operate in perpetuity and, therefore, have indeterminate cash flow estimates. Since that exposure is in perpetuity and cannot be measured, no liability will be recorded pursuant to SFAS 143. KeySpan's ARO will be re-evaluated in future periods until sufficient information exists to determine a reasonable estimate of fair value.

Financial Guarantees: KeySpan has issued financial guarantees in the normal course of business, primarily on behalf of its subsidiaries, to various third party creditors. At December 31, 2003, the following amounts would have to be paid by KeySpan in the event of non-payment by the primary obligor at the time payment is due:

(In Thousands of Dollars)		Amount of Exposure	Expiration Dates
Guarantees for Subsidiaries			
Medium-Term Notes - KEDLI	(i)	$ 525,000	2008-2010
Industrial Development Revenue Bonds	(ii)	128,000	2027
Master Lease - Ravenswood	(iii)	425,000	2004
Surety Bonds	(iv)	168,000	Revolving
Commodity Guarantees and Other	(v)	43,000	2005
Letters of Credit	(vi)	67,000	2004
		$ 1,356,000	

The following is a description of KeySpan's outstanding subsidiary guarantees:

(i) KeySpan has fully and unconditionally guaranteed $525 million to holders of Medium-Term Notes issued by KEDLI. These notes are due to be repaid on January 15, 2008 and February 1, 2010. KEDLI is required to comply with certain financial covenants under the debt agreements. Currently, KEDLI is in compliance with all covenants and management does not anticipate that KEDLI will have any difficulty maintaining such compliance. The face value of these notes are included in long-term debt on the Consolidated Balance Sheet.

(ii) KeySpan has fully and unconditionally guaranteed the payment obligations of its subsidiaries with regard to $128 million of Industrial Development Revenue Bonds issued through the Nassau County and Suffolk County Industrial Development Authorities for the construction of the Glenwood and Port Jefferson electric-generation peaking plants. The face value of these notes are included in long-term debt on the Consolidated Balance Sheet.

(iii) KeySpan has guaranteed all payment and performance obligations of KeySpan Ravenswood, LLC, the lessee under the $425 million Master Lease associated with the lease of the Ravenswood facility. The initial term of the lease expires on June 20, 2004 and may be extended until June 20, 2009.

(iv) KeySpan has agreed to indemnify the issuers of various surety and performance bonds associated with certain construction projects currently being performed by subsidiaries within the Energy Services segment. In the event that the operating companies in the Energy Services segment fail to perform their obligations under contracts, the injured party may demand that the surety make payments or provide services under the bond. KeySpan would then be obligated to reimburse the surety for any expenses or cash outlays it incurs.

(v) KeySpan has guaranteed commodity-related payments for subsidiaries within the Energy Services segment, as well as KeySpan Ravenswood, LLC. These guarantees are provided to third parties to facilitate physical and financial transactions involved in the purchase of natural gas, oil and other petroleum products for electric production and marketing activities. The guarantees cover actual purchases by these subsidiaries that are still outstanding as of December 31, 2003.

(vi) KeySpan has issued stand-by letters of credit in the amount of $67 million to third parties that have extended credit to certain subsidiaries. Certain vendors require us to post letters of credit to guarantee subsidiary performance under our contracts and to ensure payment to our subsidiary subcontractors and vendors under those contracts. Certain of our vendors also require letters of credit to ensure reimbursement for amounts they are disbursing on behalf of our subsidiaries, such as to beneficiaries under our self-funded insurance programs. Such letters of credit are generally issued by a bank or similar financial institution. The letters of credit commit the issuer to pay specified amounts to the holder of the letter of credit if the holder demonstrates that we have failed to perform specified actions. If this were to occur, KeySpan would be required to reimburse the issuer of the letter of credit.

To date, KeySpan has not had a claim made against it for any of the above guarantees or letters of credit and we have no reason to believe that our subsidiaries will default on their current obligations. However, we cannot predict when or if any defaults may take place or the impact such defaults may have on our consolidated results of operations, financial condition or cash flows.

In June 2003, Hawkeye Electric, LLC et al. ("Hawkeye") and KeySpan reached an agreement settling certain legal matters. Under the terms of the settlement: (i) certain obligations between the parties have been modified and clarified, (ii) certain contracts were awarded to Hawkeye, (iii) certain credit and bonding support made available by KeySpan to Hawkeye was terminated and (iv) KeySpan and a Hawkeye affiliate closed on a $55 million long-term note receivable due from Hawkeye on July 20, 2018 bearing interest at an annual rate of 5% and secured by a power plant in Greenport, New York.

Fixed Charges Under Firm Contracts: Our utility subsidiaries and the Ravenswood facility have entered into various contracts for gas delivery, storage and supply services. Certain of these contracts require payment of annual demand charges in the aggregate amount of approximately $452 million. We are liable for these payments regardless of the level of service we require from third parties. Such charges associated with gas distribution operations are currently recovered from utility customers through the gas adjustment clause.

Legal Matters: From time to time we are subject to various legal proceedings arising out of the ordinary course of our business. Except as described below, we do not consider any of such proceedings to be material to our business or likely to result in a material adverse effect on our results of operations, financial condition or cash flows.

KeySpan has been cooperating in preliminary inquiries regarding trading in KeySpan Corporation stock by individual officers of KeySpan prior to the July 17, 2001 announcement that KeySpan was taking a special charge in its Energy Services business and otherwise reducing its 2001 earnings forecast. These inquiries are being conducted by the U.S. Attorney's Office, Southern District of New York and the SEC.

On March 5, 2002, the SEC, as part of its continuing inquiry, issued a formal order of investigation, pursuant to which it will review the trading activity of certain company insiders from May 1, 2001 to the present, as well as KeySpan's compliance with its reporting rules and regulations, generally during the period following the acquisition by KeySpan Services, Inc., a KeySpan subsidiary, of the Roy Kay companies through the July 17, 2001 announcement.

KeySpan and certain of its current and former officers and directors are defendants in a consolidated class action lawsuit filed in the United States District Court for the Eastern District of New York. This lawsuit alleges, among other things, violations of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934, as amended ("Exchange Act"), in connection with disclosures relating to or following the acquisition of the Roy Kay companies. In October 2001, a shareholder's derivative action was commenced in the same court against certain current and former officers and directors of KeySpan, alleging, among other things, breaches of fiduciary duty, violations of the New York Business Corporation Law and violations of Section 20(a) of the Exchange Act. On June 12, 2002, a second derivative action was commenced which asserted similar allegations. Each of these proceedings seeks monetary damages in an unspecified amount. On March 18, 2003, the court granted our motion to dismiss the class action complaint. The court's order dismissed certain class allegations with prejudice, but provided the plaintiffs a final opportunity to file an amended complaint concerning the remaining allegations. In April 2003, plaintiffs filed an amended complaint and in July 2003 the court denied our motion to dismiss the amended complaint but did strike certain allegations. On November 20, 2003, the court granted our motion for reconsideration of the July 2003 order and the court struck additional allegations from the amended complaint which effectively limited the potential class period. On December 19, 2003, KeySpan filed a motion to dismiss the derivative actions. The motion is still pending. KeySpan intends to vigorously defend each of these proceedings. However, we are unable to predict the outcome of these proceedings or what effect, if any, such outcome will have on our financial condition, results of operations or cash flows.

KeySpan subsidiaries, along with several other parties, have been named as defendants in numerous proceedings filed by plaintiffs claiming various degrees of injury from asbestos exposure at generating facilities formerly owned by LILCO and others. In connection with the May 1998 transaction with LIPA, costs incurred by KeySpan for liabilities for asbestos exposure arising from the activities of the generating facilities previously owned by LILCO are recoverable from LIPA through the Power Supply Agreement between LIPA and KeySpan.

KeySpan is unable to determine the outcome of the other outstanding asbestos proceedings, but does not believe that such outcomes, if adverse, will have a material effect on its financial condition, results of operation or cash flows. KeySpan believes that its cost recovery rights under the Power Supply Agreement, its indemnification rights against third parties and its insurance coverage (above applicable deductible limits) cover its exposure for asbestos liabilities generally.

As previously reported, KeySpan, through its subsidiary, formerly known as Roy Kay, Inc., has terminated the employment of the former owners of the Roy Kay companies and commenced a proceeding in the Chancery Division of the Superior Court, Monmouth County, New Jersey (Docket No. Mon. C. 95-01) as a result of the alleged fraudulent acts of the former owners, both before and after the acquisition of the Roy Kay companies in January 2000. KeySpan commenced this proceeding because it believed that, among other things, the former owners misstated the financial statements of the Roy Kay companies and certain underlying work-in-progress schedules. The former owners filed counterclaims against KeySpan and certain of its subsidiaries, as well as certain of their respective officers, to recover damages they claimed to have incurred as a result of, among other things, their alleged improper termination and the alleged fraud on the part of KeySpan in failing to disclose the limitations imposed upon the Roy

Kay companies, with respect to the performance of certain services under PUHCA. In March 2004, KeySpan entered into an agreement with these former owners settling this proceeding, the terms of which did not have a material effect on our financial condition or results of operations.

Other Contingencies: We derive a substantial portion of our revenues in our Electric Services segment from a series of agreements with LIPA pursuant to which we manage LIPA's transmission and distribution system and supply the majority of LIPA's customers' electricity needs. The agreements terminate at various dates between May 28, 2006 and May 28, 2013, and at this time, we can provide no assurance that any of the agreements will be renewed or extended, or if they were to be renewed or extended, the terms and conditions thereof. In addition, given the complexity of these agreements, disputes arise from time to time between KeySpan and LIPA concerning the rights and obligations of each party to make and receive payments as required pursuant to the terms of these agreements. As a result, KeySpan is unable to determine what effect, if any, the ultimate resolution of these disputes will have on its financial condition or results of operations.

Environmental Matters

Air: With respect to NOx emissions reduction requirements for our existing power plants, we are required to be in compliance with the Phase III reduction requirements of the Ozone Transportation Commission memorandum by May 1, 2003, and we fully expect to achieve such emission reductions on time and in a cost-effective manner.

Water: Additional capital expenditures associated with the renewal of the surface water discharge permits for our power plants may be required by the Department of Environmental Conservation ("DEC"). Until our monitoring obligations are completed and changes to the Environmental Protection Agency regulations under Section 316 of the Clean Water Act are promulgated, the need for and the cost of equipment upgrades cannot be determined.

Land, Manufactured Gas Plants and Related Facilities

New York Sites: Within the State of New York we have identified 43 historical manufactured gas plant ("MGP") sites and related facilities, which were owned or operated by KeySpan subsidiaries or such companies' predecessors. These former sites, some of which are no longer owned by us, have been identified to the NYPSC and the DEC for inclusion on appropriate site inventories. Administrative Orders on Consent ("ACO") or Voluntary Cleanup Agreements ("VCA") have been executed with the DEC to address the investigation and remediation activities associated with certain sites. Investigation and remediation activities required at the remaining sites will be addressed as part of an application KeySpan submitted to the DEC in October 2003 under its Voluntary Cleanup Program ("VCA Application").

We have identified 28 of these sites as being associated with the historical operations of KEDNY. One site has been fully remediated. The remaining sites will be investigated and, if necessary, remediated under the terms and conditions of ACOs or VCAs. Expenditures incurred to date by us with respect to KEDNY MGP-related activities total $38.8 million. In July 2001, KEDNY filed a complaint for the recovery of its remediation costs in the New York State Supreme Court against the various insurance companies that issued general comprehensive liability policies to KEDNY. The outcome of this proceeding cannot yet be determined.

The remaining 15 sites have been identified as being associated with the historical operations of KEDLI. Expenditures incurred to date by us with respect to KEDLI MGP-related activities total $32.2 million. One site has been fully investigated and requires no further action. The remaining sites will be investigated and, if necessary, remediated under the conditions of ACOs or VCAs. In January 1998, KEDLI filed a complaint for the recovery of its remediation costs in the New York State Supreme Court against the various insurance companies that issued general comprehensive liability policies to KEDLI. The outcome of this proceeding cannot yet be determined.

We presently estimate the remaining cost of our KEDNY and KEDLI MGP-related environmental remediation activities will be $226.4 million, which amount has been accrued by us as a reasonable estimate of probable cost for known sites. Expenditures incurred to date by us with respect to these MGP-related activities total $71 million.

With respect to remediation costs, the KEDNY rate plan provides, among other things, that if the total cost of investigation and remediation varies from that which is specifically estimated for a site under investigation and/or remediation, then KEDNY will retain or absorb up to 10% of the variation. The KEDLI rate plan also provides for the recovery of investigation and remediation costs but with no consideration of the difference between estimated and actual costs. At December 31, 2003, we have reflected a regulatory asset of $245.3 million for our KEDNY/KEDLI MGP sites. In accordance with NYPSC policy, KeySpan records a reduction to regulatory liabilities as costs are incurred for environmental clean-up activities. At December 31, 2003, these previously deferred regulatory liabilities totaled $61.0 million. In October 2003, KEDNY and KEDLI filed a joint petition with the NYPSC seeking rate treatment for additional environmental costs that may be incurred in the future.

We are also responsible for environmental obligations associated with the Ravenswood facility, purchased from Consolidated Edison in 1999, including remediation activities associated with its historical operations and those of the MGP facilities that formerly operated at the site. We are not responsible for liabilities arising from disposal of waste at off-site locations prior to the acquisition closing and any monetary fines arising from Consolidated Edison's pre-closing conduct. We presently estimate the remaining environmental clean up activities for this site will be $3.4 million, which amount has been accrued by us. Expenditures incurred to date total $1.6 million.

New England Sites: Within the Commonwealth of Massachusetts and the State of New Hampshire, we are aware of 76 former MGP sites and related facilities within the existing or former service territories of KEDNE.

Boston Gas Company, Colonial Gas Company and Essex Gas Company may have or share responsibility under applicable environmental laws for the remediation of 66 of these sites. A subsidiary of National Grid USA ("National Grid"), formerly New England Electric System, has assumed responsibility for remediating 11 of these sites, subject to a limited contribution from Boston Gas Company, and has provided full indemnification to Boston Gas Company with respect to 8 other sites. In addition, Boston Gas Company, Colonial Gas Company, and Essex Gas Company have each assumed responsibility for remediating 3 sites. At this time, it is uncertain as to whether Boston Gas Company, Colonial Gas Company or Essex Gas Company have or share responsibility for remediating any of the other sites. No notice of responsibility has been issued to us for any of these sites from any governmental environmental authority.

In March 1999, Boston Gas Company and a subsidiary of National Grid filed a complaint for the recovery of remediation costs in the Massachusetts Superior Court against various insurance companies that issued comprehensive general liability policies to National Grid and its predecessors with respect to, among other things, the 11 sites for which Boston Gas Company has agreed to make a limited contribution. In October 2002, Boston Gas Company filed a complaint in the United States District Court – Massachusetts District against one of the insurance companies that issued comprehensive general liability policies to Boston Gas Company for its remaining sites. The outcome of these proceedings cannot be determined at this time.

We presently estimate the remaining cost of these Massachusetts KEDNE MGP-related environmental cleanup activities will be $25.4 million, which amount has been accrued by us as a reasonable estimate of probable cost for known sites. Expenditures incurred since November 8, 2000 with respect to these MGP-related activities total $13.5 million.

We may have or share responsibility under applicable environmental laws for the remediation of 10 MGP sites and related facilities associated with the historical operations of EnergyNorth. At four of these sites we have entered into cost sharing agreements with other parties who share responsibility for remediation of these sites. EnergyNorth also has entered into an agreement with the United States Environmental Protection Agency ("EPA") for the contamination from the Nashua site that was allegedly commingled with asbestos at the so-called Nashua River Asbestos Site, adjacent to the Nashua MGP site.

EnergyNorth has filed suit in both the New Hampshire Superior Court and the United States District Court for the District of New Hampshire for recovery of its remediation costs against the various insurance companies that issued comprehensive general liability and excess liability insurance policies to EnergyNorth and its predecessors. Settlements have been reached with some of the carriers and one carrier was dismissed from a Superior Court action on summary judgment. The outcome of the remaining proceedings cannot yet be determined.

We presently estimate the remaining cost of EnergyNorth MGP-related environmental cleanup activities will be $13.9 million, which amount has been accrued by us as a reasonable estimate of probable cost for known sites. Expenditures incurred since November 8, 2000, with respect to these MGP-related activities total $7.8 million.

By rate orders, the DTE and the NHPUC provide for the recovery of site investigation and remediation costs and, accordingly, at December 31, 2003, we have reflected a regulatory asset of $51.5 million for the KEDNE MGP sites. As previously mentioned, Colonial Gas Company and Essex Gas Company are not subject to the provisions of SFAS 71 and therefore have recorded no regulatory asset. However, rate plans currently in effect for these subsidiaries provide for the recovery of investigation and remediation costs.

KeySpan New England LLC Sites: We are aware of three non-utility sites associated with KeySpan New England, LLC, a successor company to Eastern Enterprises, for which we may have or share environmental remediation or ongoing maintenance responsibility. These three sites, located in Philadelphia, Pennsylvania, New Haven, Connecticut and Everett, Massachusetts, were associated with historical operations involving the production of coke and related industrial processes. Honeywell International, Inc. and Beazer East, Inc. (both former owners and/or operators of certain facilities at Everett ("the Everett Facility") together with KeySpan, have entered into an ACO with the Massachusetts Department of Environmental Protection for the investigation and development of a remedial response plan for a portion of that site. KeySpan, Honeywell and Beazer East have entered into a cost-sharing agreement under which each company has agreed to pay one-third of the costs of compliance with the consent order, while preserving any claims it may have against the other companies for, among other things, reallocation of proportionate liability. In 2002, Beazer East commenced an action in the U.S. District Court for the Southern District of New York, which seeks a judicial determination on the allocation of liability for the Everett Facility. The outcome of this proceeding cannot yet be determined.

KeySpan also is recovering certain legal defense costs and may be entitled to recover remediation costs from its insurers. We presently estimate the remaining cost of our environmental cleanup activities for the three non-utility sites will be approximately $25.6 million, which amount has been accrued by us as a reasonable estimate of probable costs for known sites. Expenditures incurred since November 8, 2000, with respect to these sites total $7.2 million.

We believe that in the aggregate, the accrued liability for these MGP sites and related facilities identified above are reasonable estimates of the probable cost for the investigation and remediation of these sites and facilities. As circumstances warrant, we periodically re-evaluate the accrued liabilities associated with MGP sites and related facilities. We did such a re-evaluation in 2003 and the results of this study have been reflected in KeySpan's accruals. The re-evaluation of KeySpan's accruals resulted in a $10 million benefit to earnings in 2003. We may be required to investigate and, if necessary, remediate each site previously noted, or other currently unknown former sites and related facility sites, the cost of which is not presently determinable but may be material to our financial position, results of operations or cash flows. Remediation costs for each site may be materially higher than noted, depending upon remediation experience, selected end use for each site, and actual environmental conditions encountered.

Note 8. Hedging, Derivative Financial Instruments and Fair Values

Financially-Settled Commodity Derivative Instruments – Hedging Activities: From time to time, KeySpan subsidiaries have utilized derivative financial instruments, such as futures, options and swaps, for the purpose of hedging the cash flow variability associated with changes in commodity prices. KeySpan is exposed to commodity price risk primarily with regard to its gas exploration and production activities and its electric generating facilities. Derivative financial instruments are employed by Houston Exploration to hedge cash flow variability associated with forecasted sales of natural gas. The Ravenswood facility uses derivative financial instruments to hedge the cash flow variability associated with the purchase of natural gas and oil that will be consumed during the generation of electricity. The Ravenswood facility also hedges the cash flow variability associated with a portion of peak season electric energy sales. In addition, during 2003 KeySpan Canada employed derivative financial instruments to hedge cash flow variability associated with the purchase of natural gas and electricity used in the operation of its gas processing plants; all such derivative instruments settled during the year.

The majority of these derivative financial instruments are cash flow hedges that qualify for hedge accounting under SFAS 133 "Accounting for Derivative Instruments and Hedging Activities", as amended by SFAS 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities", collectively SFAS 133, and are not considered held for trading purposes as defined by current accounting literature. Accordingly, we carry the fair market value of our derivative instruments on the Consolidated Balance Sheet as either a current or deferred asset or liability, as appropriate, and defer the effective portion of unrealized gains or losses in accumulated other comprehensive income. Gains and losses are reclassified from accumulated other comprehensive income to the Consolidated Statement of Income in the period the hedged transaction effects earnings. Gains and losses are reflected as a component of either revenue or fuel and purchased power depending on the hedged transaction. Hedge ineffectiveness is measured using the change in variable cash flows and the hypothetical derivative methods and recorded directly to earnings.

Houston Exploration has utilized collars and purchased put options, as well as over-the-counter ("OTC") swaps, to hedge the cash flow variability associated with forecasted sales of a portion of its natural gas production. In 2003, Houston Exploration hedged slightly less than 70% of its gas production. At December 31, 2003, Houston Exploration has hedge positions in place for approximately 70% of its estimated 2004 gas production, with an effective floor price of $4.26

and an effective ceiling price of $5.65. Further, Houston Exploration has hedge positions in place for approximately 44% of its estimated 2005 gas production, with an effective floor price of $4.59 and an effective ceiling price of $5.26. Houston Exploration uses standard New York Mercantile Exchange ("NYMEX") futures prices to value its swap positions, and, in addition, uses published volatility in its Black-Scholes calculation for outstanding options. The maximum length of time over which Houston Exploration has hedged such cash flow variability is through December 2005. The fair market value of these derivative instruments at December 31, 2003 was a liability of $36.9 million. The estimated amount of losses associated with such derivative instruments that are reported in other comprehensive income and that are expected to be reclassified into earnings over the next twelve months is $32.1 million, or $20.9 million after-tax.

With respect to price exposure associated with fuel purchases for the Ravenswood facility, KeySpan employs standard NYMEX natural gas futures contracts and over-the-counter financially settled natural gas basis swaps to hedge the cash flow variability for a portion of forecasted purchases of natural gas. KeySpan also employs the use of financially-settled oil swap contracts to hedge the cash flow variability for a portion of forecasted purchases of fuel oil that will be consumed at the Ravenswood facility. The maximum length of time over which we have hedged cash flow variability associated with forecasted purchases of natural gas and fuel oil is through September 2005. We use standard NYMEX futures prices to value the gas futures contracts and market quoted forward prices to value oil swap and natural gas basis swap contracts. The fair market value of these derivative instruments at December 31, 2003 was an asset of $0.4 million. These derivative instruments are reported in other comprehensive income and are expected to be reclassified into earnings over the next twelve months.

We have also engaged in the use of cash-settled swap instruments to hedge the cash flow variability associated with a portion of forecasted peak season electric energy sales from the Ravenswood facility. The maximum length of time over which we have hedged cash flow variability is through December 2004. We use market quoted forward prices to value these outstanding derivatives. The fair market value of these derivative instruments at December 31, 2003 was an asset of $0.3 million. These derivative instruments are reported in other comprehensive income and are expected to be reclassified into earnings over the next twelve months.

The table below summarizes the fair value of each category of derivative instrument outstanding at December 31, 2003 and its related line item on the Consolidated Balance Sheet. Fair value is the amount at which derivative instruments could be exchanged in a current transaction between willing parties, other than in a forced liquidation sale.

(In Thousands of Dollars)		December 31, 2003
Gas Contracts:		
Other current assets	$	3,458
Accounts payable and other liabilities		(35,592)
Other deferred liabilities		(4,734)
Oil Contracts:		
Other deferred charges		385
Electric Contracts:		
Other deferred charges		259
	$	(36,224)

Financially-Settled Commodity Derivative Instruments that Do Not Qualify for Hedge Accounting: KeySpan subsidiaries also employ a limited number of financial derivatives that do not qualify for hedge accounting treatment under SFAS 133. In November 2003, we sold a "swaption" to hedge the cash flow variability associated with 50 MW of forecasted 2004 summer electric energy sales from the Ravenswood facility. The swaption is an option that gives the counterparty the right, but not the obligation, to enter into a swap transaction with KeySpan in the future at a given strike price. This swaption can be converted into a swap, at the election of the counterparty and has an expiration date of June 1, 2004. The premium payment KeySpan received was recorded as a current liability on the Consolidated Balance Sheet. The premium generally will be recorded into income at the time the swaption is either exercised or expires. An internally developed option-pricing model is used to value the swaption and at December 31, 2003 the fair value of the swaption was immaterial.

At December 31, 2003, KeySpan Canada has a portfolio of financially-settled natural gas collars and swap transactions for natural gas liquids. Such contracts are executed by KeySpan Canada to: (i) fix the price that is paid or received by KeySpan Canada for certain physical transactions involving natural gas and natural gas liquids and (ii) transfer the price exposure to counterparties. These derivative financial instruments also do not qualify for hedge accounting treatment. At December 31, 2003, these instruments had a net fair market value of $1.0 million, which was recorded as a $1.8 million current asset and $0.8 million current liability on the Consolidated Balance Sheet. Based on the non-hedge designation of these instruments, an unrealized gain was recorded in the Consolidated Statement of Income.

Firm Gas Sales Derivative Instruments - Regulated Utilities: We use derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with our Gas Distribution operations. Our strategy is to minimize fluctuations in firm gas sales prices to our regulated firm gas sales customers in our New York and New England service territories. The accounting for these derivative instruments is subject to SFAS 71 "Accounting for the Effects of Certain Types of Regulation." Therefore, changes in the fair value of these derivatives have been recorded as a regulatory asset or regulatory liability on the Consolidated Balance Sheet. Gains or losses on the settlement of these contracts are initially deferred and then refunded to or collected from our firm gas sales customers consistent with regulatory requirements. At December 31, 2003, these derivatives had a net fair market value of $9.9 million and are reflected as a regulatory liability on the Consolidated Balance Sheet.

Physically-Settled Commodity Derivative Instruments: SFAS 133 establishes criteria that must be satisfied in order for option contracts, forward contracts with optionality features, or contracts that combine a forward contract and a purchase option contract to be exempted as normal purchases and sales. Based upon a continuing review of our physical gas contracts, we determined that certain contracts for the physical purchase of natural gas associated with our regulated gas utilities are not exempt as normal purchases from the requirements of SFAS 133. Since these contracts are for the purchase of natural gas sold to regulated firm gas sales customers, the accounting for these contracts is subject to SFAS 71. Therefore, changes in the market value of these contracts have been recorded as a regulatory asset or regulatory liability on the Consolidated Balance Sheet. At December 31, 2003 these contracts had a net negative fair market value of $1.9 million, and are reflected as a $6.9 million regulatory asset and $5.0 million regulatory liability on the Consolidated Balance Sheet.

Interest Rate Derivative Instruments: In May 2003, we entered into interest rate swap agreements in which we swapped $250 million of 7.25% fixed rate debt to floating rate debt. Under the terms of the agreements, we will receive the fixed coupon rate associated with these bonds and pay our swap counterparties a variable interest rate based on LIBOR, that is reset on a semi-annual basis. These swaps are designated as fair-value hedges and qualify for "short-cut" hedge accounting treatment under SFAS 133. During the twelve months ended December 31, 2003, we paid our counterparty an average interest rate of 6.43%, and as a result, we realized interest savings of $1.2 million. The fair market value of this derivative was negligible at December 31, 2003.

During 2002, we had interest rate swap agreements in which we swapped approximately $1.3 billion of fixed rate debt to floating rate debt. Under the terms of the agreements, we received the fixed coupon rate associated with these bonds and paid the swap counterparties a variable interest rate that was reset on a quarterly basis. These swaps were designated as fair-value hedges and qualified for "short-cut" hedge accounting treatment under SFAS 133. In 2002, we terminated two of these interest rate swap agreements with an aggregate notional amount of $1.0 billion. The remaining swap, which had a notional amount of $270.0 million, was terminated on February 25, 2003. We received $18.4 million from our swap counterparties as a result of the latter termination, of which $8.1 million represented accrued swap interest. The difference between the termination settlement amount and the amount of accrued interest, $10.3 million, was recorded as a reduction to interest expense in the first quarter of 2003. This swap was used to hedge a portion of our outstanding promissory notes to LIPA. As discussed in Note 6 "Long-Term Debt," we called a portion of these promissory notes during the first quarter of 2003.

Additionally, we had an interest rate swap agreement that hedged the cash flow variability associated with the forecasted issuance of a series of commercial paper offerings. This hedge expired in March 2003.

Weather Derivatives: The utility tariffs associated with KEDNE's operations do not contain weather normalization adjustments. As a result, fluctuations from normal weather may have a significant positive or negative effect on the results of these operations. To mitigate a substantial portion of the effect of fluctuations from normal weather on our financial position and cash flows, we sold heating degree-day call options and purchased heating-degree day put options for the November 2002-March 2003 winter season. With respect to sold call options, KeySpan was required to make a payment of $40,000 per heating degree day to its counterparties when actual weather experienced during the November 2002 - March 2003 time frame was above 4,470 heating degree days, which equates to approximately 1% colder than normal weather. With respect to purchased put options, KeySpan would have received a $20,000 per heating degree day payment from its counterparties when actual weather was below 4,150 heating degree days, or approximately 7% warmer than normal. Based on the terms of such contracts, we account for such instruments pursuant to the requirements of EITF 99-2, "Accounting for Weather Derivatives." In this regard, such instruments were accounted for using the "intrinsic value method" as set forth in such guidance. During the first quarter of 2003, weather was 10% colder than normal and, as a result, $11.9 million was recorded as a reduction to revenues.

In October 2003, we entered into heating-degree day call and put options to mitigate the effect of fluctuations from normal weather on KEDNE's financial position and cash flows for the 2003/2004 winter heating season – November 2003 through March 2004. With respect to sold call options, KeySpan will be required to make a payment of $27,500 per heating degree day to its counterparties when actual weather experienced during this time frame is above 4,440 heating degree days, which equates to approximately 2% colder than normal weather, based on the most recent 20-year average for normal weather. The maximum amount KeySpan may be required to pay on its sold call options is $5.5 million. With respect to purchased put options, KeySpan will receive a $27,500 per heating degree day payment from its counterparties when actual weather is below 4,266 heating degree days, or approximately 2% warmer than normal. The maximum amount KeySpan may receive on its purchased put options is $11 million. The net premium cost for these options was $0.4 million. We account for these derivatives pursuant to the requirements of EITF 99-2. During the fourth quarter of 2003, weather, as measured in heating degree-days, was slightly warmer normal and, as a result, a $0.5 million benefit was recorded through revenues.

Derivative contracts are primarily used to manage exposure to market risk arising from changes in commodity prices and interest rates. In the event of non-performance by a counterparty to a derivative contract, the desired impact may not be achieved. The risk of counterparty non-performance is generally considered a credit risk and is actively managed by assessing each counterparty credit profile and negotiating appropriate levels of collateral and credit support. We believe that our credit risk related to the above mentioned derivative financial instruments is no greater than the risk associated with the primary contracts which they hedge and that the elimination of a portion of the price risk reduces volatility in our reported results of operations, financial position and cash flows and lowers overall business risk.

Long-term Debt: The following tables depict the fair values and carrying values of KeySpan's long-term debt at December 31, 2003 and 2002.

Fair Values of Long-Term Debt

	Year Ended December 31,	
(In Thousands of Dollars)	2003	2002
First Mortgage Bonds	$ 178,438	$ 180,666
Notes	3,893,158	3,441,619
Gas Facilities Revenue Bonds	683,354	674,828
Authority Financing Notes	66,005	66,005
Promissory Notes	158,837	616,240
MEDS Equity Units	495,880	525,918
Tax Exempt Bonds	129,558	-
	$ 5,605,230	$ 5,505,276

Carrying Values of Long-Term Debt

(In Thousands of Dollars)	2003	2002
First Mortgage Bonds	$ 153,186	$ 163,625
Notes	3,456,425	2,985,000
Gas Facilities Revenue Bonds	648,500	648,500
Authority Financing Notes	66,005	66,005
Promissory Notes	155,422	602,427
MEDS Equity Units	460,000	460,000
Master Lease	412,300	-
Tax Exempt Bonds	128,275	-
	$ 5,480,113	$ 4,925,557

Our subsidiary debt is carried at an amount approximating fair value because interest rates are based on current market rates. All other financial instruments included in the Consolidated Balance Sheet such as cash, commercial paper, accounts receivable and accounts payable, are also stated at amounts that approximate fair value.

Note 9. Discontinued Operations

On November 8, 2000, KeySpan acquired Midland Enterprises LLC ("Midland"), an inland marine transportation subsidiary, as part of the Eastern acquisition. In its order approving the acquisition, the SEC required KeySpan to sell this subsidiary by November 8, 2003 because Midland's operations were not functionally related to KeySpan's core utility operations. On July 2, 2002, the sale of Midland to Ingram Industries Inc. was completed and net proceeds of $175.1 million were received from the sale.

Discontinued operations for the year ended December 31, 2001 included an anticipated after-tax loss on disposal of $30.4 million. As a result of a change in the tax structuring strategy related to the sale of Midland, in the second quarter of 2002 we recorded an additional provision for city and state taxes and made adjustments to the estimates used in the December 31, 2001 loss provision. These changes resulted in an additional after tax loss on disposal of $19.7 million.

The following is selected financial information for Midland for the period January 1, 2002 through July 2, 2002 and the year ended December 31, 2001:

(In Thousands of Dollars)	2002	2001
Revenues	$ 116,149	$ 266,792
Pre-tax income (loss)	(4,624)	18,489
Income tax (expense) benefit	1,268	(7,571)
Income (loss) from discontinued operations	(3,356)	10,918
Estimated book gain on disposal	5,980	44,580
Tax expense associated with disposal	(22,286)	(74,936)
Estimated loss on disposal	(16,306)	(30,356)
Loss from discontinued operations	$ (19,662)	$ (19,438)

Note 10. Roy Kay Operations

During 2001, we undertook a complete evaluation of the strategy, operating controls and organizational structure of the Roy Kay companies - plumbing, mechanical, electrical and general contracting companies acquired by us in January 2000. We decided to discontinue the general contracting business conducted by these companies based upon our view that the general contracting business is not a core competency of these companies. Certain remaining activities engaged in by the Roy Kay companies have been integrated with those of other KeySpan energy-related businesses. During 2002, substantially all of the remaining field work on outstanding construction projects was completed. We are now engaged in the finalization of claims and collections and, as a result, their operations will continue to be consolidated in our Consolidated Financial Statements until such time as this process is complete. During 2003 KeySpan incurred $11.4 million in operating losses which reflect provisions made for the resolution of outstanding claims and change orders, as well as additional costs incurred in connection with the collection of outstanding contract balances.

For the year ended December 31, 2001, the Roy Kay companies incurred an after-tax loss of $95.0 million ($137.8 million pre-tax) reflecting: (i) unanticipated costs to complete work on certain construction projects; (ii) the impact of inaccuracies in the books of these companies relating to their overall financial and operational performance; (iii) discontinuance costs of the general contracting activities of those companies, including the write-off of goodwill, and certain account and retainage receivables; and (iv) operating losses. For the years ended December 31, 2002 and 2001 the Roy Kay companies recorded operating losses of $10.8 million and $137.8 million respectively. KeySpan and the former Roy Kay companies are currently engaged in litigation relating to the termination of the former owners, as well as other matters relating to the acquisition of the Roy Kay companies. (See Note 7 "Contractual Obligations and Contingencies" - Legal Matters.)

Note 11. Class Action Settlement

During 2001, we reversed a previously recorded loss provision regarding certain pending rate refund issues relating to the 1989 RICO class action settlement. This adjustment resulted from a favorable United States Court of Appeals ruling received on September 28, 2001, overturning a lower court decision, and resulted in a positive pre-tax adjustment to earnings of $33.5 million, or $20.1 million after-tax. This adjustment has been reflected as a $22.0 million reduction to operations and maintenance expense and a reduction of $11.5 million to interest expense on the Consolidated Statement of Income.

Note 12. KeySpan Gas East Corporation Summary Financial Data

KEDLI is a wholly owned subsidiary of KeySpan. KEDLI was formed on May 7, 1998 and on May 28, 1998 acquired substantially all of the assets related to the gas distribution business of LILCO. KEDLI provides gas distribution services to customers in the Long Island counties of Nassau and Suffolk and the Rockaway peninsula of Queens county. KEDLI established a program for the issuance, from time to time, of up to $600 million aggregate principal amount of Medium-Term Notes, which will be fully and unconditionally guaranteed by the parent, KeySpan Corporation. On February 1, 2000, KEDLI issued $400 million of 7.875% Medium-Term Notes due 2010. In January 2001, KEDLI issued an additional $125 million of Medium-Term Notes at 6.9% due January 2008. The following condensed financial statements are required to be disclosed by SEC regulations and set forth those of KEDLI, KeySpan Corporation as guarantor of the Medium- Term Notes and our other subsidiaries on a combined basis.

(In Thousands of Dollars)	Guarantor	KEDLI	Other Subsidiaries	Eliminations	Consolidated
	Year Ended December 31, 2003				
Revenues	$ 507	$ 1,046,931	$ 5,868,230	$ (507)	$ 6,915,161
Operating Expenses					
Purchased gas	-	574,009	1,921,093	-	2,495,102
Fuel and purchased power	-	-	414,633	-	414,633
Operations and maintenance	11,340	137,223	1,857,233	-	2,005,796
Intercompany expense	5,282	3,570	(3,570)	(5,282)	-
Depreciation and amortization	(53)	77,603	496,524	-	574,074
Operating taxes	-	77,503	340,733	-	418,236
Total Operating Expenses	16,569	869,908	5,026,646	(5,282)	5,907,841
Gain on sale of property	-	13,974	1,149	-	15,123
Income from equity investments	108	-	19,106	-	19,214
Operating Income (Loss)	(15,954)	190,997	861,839	4,775	1,041,657
Interest charges	(209,505)	(62,992)	(299,399)	264,202	(307,694)
Other income and (deductions)	621,151	(8,636)	54,429	(699,415)	(32,471)
Total Other Income and (Deductions)	411,646	(71,628)	(244,970)	(435,213)	(340,165)
Income Taxes (Benefit)	(28,663)	40,796	265,178	-	277,311
Earnings from Continuing Operations	$ 424,355	$ 78,573	$ 351,691	$ (430,438)	$ 424,181
Cumulative Change in Accounting Principle	-	-	(37,451)	-	(37,451)
Net Income	$ 424,355	$ 78,573	$ 314,240	$ (430,438)	$ 386,730

Statement of Income

(In Thousands of Dollars)	Guarantor	KEDLI	Other Subsidiaries	Eliminations	Consolidated
	Year Ended December 31, 2002				
Revenues	$ 463	$ 810,601	$ 5,160,065	$ (463)	$ 5,970,666
Operating Expenses					
Purchased gas	-	379,742	1,273,531	-	1,653,273
Fuel and purchased power	-	-	395,860	-	395,860
Operations and maintenance	13,325	45,357	2,043,215	-	2,101,897
Intercompany expense	2,772	79,826	(79,826)	(2,772)	-
Depreciation and amortization	(44)	65,911	448,746	-	514,613
Operating taxes	(2,149)	80,056	303,860	-	381,767
Total Operating Expenses	13,904	650,892	4,385,386	(2,772)	5,047,410
Gain on sale of property	-	317	4,413	-	4,730
Income from equity investments	104	-	13,992	-	14,096
Operating Income (Loss)	(13,337)	160,026	793,084	2,309	942,082
Interest charges	(200,920)	(62,520)	(295,209)	257,145	(301,504)
Other income and (deductions)	565,262	7,835	60,222	(633,068)	251
Total Other Income and (Deductions)	364,342	(54,685)	(234,987)	(375,923)	(301,253)
Income Taxes (Benefit)	(26,683)	36,746	233,416	-	243,479
Earnings from Continuing Operations	$ 377,688	$ 68,595	$ 324,681	$ (373,614)	$ 397,350
Discontinued Operations	-	-	(19,662)	-	(19,662)
Net Income	$ 377,688	$ 68,595	$ 305,019	$ (373,614)	$ 377,688

Statement of Income					
	Year Ended December 31, 2001				
(In Thousands of Dollars)	Guarantor	KEDLI	Other Subsidiaries	Eliminations	Consolidated
Revenues	$ 504	$ 889,693	$ 5,743,422	$ (504)	$ 6,633,115
Operating Expenses					
Purchased gas	-	464,780	1,706,333	-	2,171,113
Fuel and purchased power	-	-	538,532	-	538,532
Operations and maintenance	(24,537)	45,106	2,094,190	-	2,114,759
Intercompany expense	278	87,738	(87,738)	(278)	-
Depreciation and amortization	4,273	56,274	498,591	-	559,138
Operating taxes	1,094	91,204	356,626	-	448,924
Total Operating Expenses	(18,892)	745,102	5,106,534	(278)	5,832,466
Income from equity investments	-	-	13,129	-	13,129
Operating Income (Loss)	19396	144,591	650,017	(226)	813,778
Interest charges	(230,618)	(65,206)	(264,286)	206,640	(353,470)
Other income and (deductions)	426,346	9,721	5,326	(447,316)	(5,923)
Total Other Income and (Deductions)	195,728	(55,485)	(258,960)	(240,676)	(359,393)
Income Taxes (Benefit)	(9,130)	28,319	191,504	-	210,693
Earnings from Continuing Operations	$ 224,254	$ 60,787	$ 199,553	$ (240,902)	$ 243,692
Discontinued Operations	-	-	(19,438)	-	(19,438)
Net Income	$ 224,254	$ 60,787	$ 180,115	$ (240,902)	$ 224,254

Balance Sheet

(In Thousands of Dollars)	Guarantor	KEDLI	December 31, 2003 Other Subsidiaries	Eliminations	Consolidated
ASSETS					
Current Assets					
Cash and temporary cash investments	$ 97,567	$ 1,554	$ 106,630	$ -	$ 205,751
Accounts receivable, net	3,298	209,151	1,243,459	-	1,455,908
Other current assets	3,250	130,994	590,996	-	725,240
	104,115	341,699	1,941,085	-	2,386,899
Equity Investments	4,475,949	1,123	153,520	(4,382,027)	248,565
Property					
Gas	-	1,899,375	4,622,876	-	6,522,251
Other	-	-	6,150,355	-	6,150,355
Accumulated depreciation and depletion	-	(312,204)	(3,466,099)	-	(3,778,303)
	-	1,587,171	7,307,132	-	8,894,303
Intercompany Accounts Receivable	3,105,571	-	1,191,394	(4,296,965)	-
Deferred Charges	374,076	237,870	2,485,071	-	3,097,017
Total Assets	$ 8,059,711	$ 2,167,863	$ 13,078,202	$ (8,678,992)	$ 14,626,784
LIABILITIES AND CAPITALIZATION					
Current Liabilities					
Accounts payable	$ 125,892	$ 165,613	$ 850,092	$ -	$ 1,141,597
Notes payable	481,900	-	-	-	481,900
Other current liabilities	129,168	16,125	80,026	-	225,319
	736,960	181,738	930,118	-	1,848,816
Intercompany Accounts Payable	-	116,197	2,596,202	(2,712,399)	-
Deferred Credits and Other Liabilities					
Deferred income tax	(48,059)	256,882	1,064,828	-	1,273,651
Other deferred credits and liabilities	532,062	179,919	925,839	-	1,637,820
	484,003	436,801	1,990,667	-	2,911,471
Capitalization					
Common shareholders' equity	3,707,785	782,223	3,553,967	(4,382,027)	3,661,948
Preferred stock	83,568	-	-	-	83,568
Long-term debt	3,047,395	650,904	3,497,699	(1,584,566)	5,611,432
Total Capitalization	6,838,748	1,433,127	7,051,666	(5,966,593)	9,356,948
Minority Interest in Subsidiary Companies	-	-	509,549	-	509,549
Total Liabilities & Capitalization	$ 8,059,711	$ 2,167,863	$ 13,078,202	$ (8,678,992)	$ 14,626,784

Balance Sheet					
			December 31, 2002		
(In Thousands of Dollars)	Guarantor	KEDLI	Other Subsidiaries	Eliminations	Consolidated
ASSETS					
Current Assets					
Cash & temporary cash investments	$ 88,308	$ 6,472	$ 75,837	$ -	$ 170,617
Accounts receivable, net	23,982	208,512	1,299,559	-	1,532,053
Other current assets	1,757	79,206	423,596	-	504,559
	114,047	294,190	1,798,992	-	2,207,229
Equity Investments	3,797,964	1,469	201,675	(3,736,379)	264,729
Property					
Gas	-	1,773,028	4,352,501	-	6,125,529
Other	-	-	4,807,724	-	4,807,724
Accumulated depreciation and depletion	-	(282,832)	(3,065,829)	-	(3,348,661)
	-	1,490,196	6,094,396	-	7,584,592
Intercompany Accounts Receivable	3,619,515	-	712,394	(4,331,909)	-
Deferred Charges	339,443	192,652	2,391,405	-	2,923,500
Total Assets	$ 7,870,969	$ 1,978,507	$ 11,198,862	$ (8,068,288)	$ 12,980,050
LIABILITIES AND CAPITALIZATION					
Current Liabilities					
Accounts payable	$ 132,966	$ 68,772	$ 894,916	$ -	$ 1,096,654
Notes payable	915,697	-	-	-	915,697
Other current liabilities	107,605	104,975	30,302	-	242,882
	1,156,268	173,747	925,218	-	2,255,233
Intercompany Accounts Payable	-	178,843	2,071,682	(2,250,525)	-
Deferred Credits and Other Liabilities					
Deferred income tax	(43,110)	139,715	780,408	-	877,013
Other deferred credits and liabilities	481,964	138,209	744,688	-	1,364,861
	438,854	277,924	1,525,096	-	2,241,874
Capitalization					
Common shareholders' equity	2,983,214	647,089	3,050,668	(3,736,379)	2,944,592
Preferred stock	83,849	-	-	-	83,849
Long-term debt	3,208,784	700,904	3,395,777	(2,081,384)	5,224,081
Total Capitalization	6,275,847	1,347,993	6,446,445	(5,817,763)	8,252,522
Minority Interest in Subsidiary Companies	-	-	230,421	-	230,421
Total Liabilities & Capitalization	$ 7,870,969	$ 1,978,507	$ 11,198,862	$ (8,068,288)	$ 12,980,050

Statement of Cash Flows

(In Thousands of Dollars)	Year Ended December 31, 2003 Guarantor	KEDLI	Other Subsidiaries	Consolidated
Operating Activities				
Net Cash (Used in) Provided by Operating Activities	$ (547,516)	$ 162,786	$ 1,569,373	$ 1,184,643
Investing Activities				
Capital expenditures	-	(130,275)	(881,441)	(1,011,716)
Proceeds from the sale of property and subsidiary stock	-	15,123	294,573	309,696
Investments in subsidiaries	-	-	(211,370)	(211,370)
Issuance of note receiveable	(55,000)	-	-	(55,000)
Net Cash (Used in) Investing Activities	(55,000)	(115,152)	(798,238)	(968,390)
Financing Activities				
Proceeds from equity issuance	473,573	-		473,573
Treasury stock issued	96,687	-	-	96,687
Redemption of LIPA promissory notes	(447,005)	-		(447,005)
Issuance of debt, net of payments	300,000	-	119,287	419,287
Redemption of preferred stock		-	(14,293)	(14,293)
Payment of commercial paper	(433,797)	-		(433,797)
Common and preferred stock dividends paid	(280,560)	-		(280,560)
Other	28,933	-	(23,944)	4,989
Net intercompany accounts	873,944	(52,552)	(821,392)	-
Net Cash Provided by (Used in) Financing Activities	611,775	(52,552)	(740,342)	(181,119)
Net (Decrease) Increase in Cash and Cash Equivalents	$ 9,259	$ (4,918)	$ 30,793	$ 35,134
Cash and Cash Equivalents at Beginning of Period	88,308	6,472	75,837	170,617
Cash and Cash Equivalents at End of Period	$ 97,567	$ 1,554	$ 106,630	$ 205,751

Statement of Cash Flows

(In Thousands of Dollars)	Year Ended December 31, 2002 Guarantor	KEDLI	Other Subsidiaries	Consolidated
Operating Activities				
Net Cash (Used in) Provided by Operating Activities	$ (97,981)	$ 188,955	$ 640,518	$ 731,492
Investing Activities				
Capital expenditures	-	(146,450)	(914,572)	(1,061,022)
Other	-	903	151,358	152,261
Net Cash (Used in) Investing Activities	-	(145,547)	(763,214)	(908,761)
Financing Activities				
Treasury stock issued	86,710	-	-	86,710
Issuance (payment) of debt, net	327,247	-	(35,711)	291,536
Common and preferred stock dividends paid	(256,656)	-		(256,656)
Other	70,299	-	(3,255)	67,044
Net intercompany accounts	(41,311)	(36,936)	78,247	-
Net Cash Provided by (Used in) Financing Activities	186,289	(36,936)	39,281	188,634
Net (Decrease) Increase in Cash and Cash Equivalents	$ 88,308	$ 6,472	$ (83,415)	$ 11,365
Cash and Cash Equivalents at Beginning of Period	-	-	159,252	159,252
Cash and Cash Equivalents at End of Period	$ 88,308	$ 6,472	$ 75,837	$ 170,617

Statement of Cash Flows				
	Year Ended December 31, 2001			
(In Thousands of Dollars)	Guarantor	KEDLI	Other Subsidiaries	Consolidated
Operating Activities				
Net Cash Provided by Operating Activities	$ 121,028	$ 64,294	$ 704,859	$ 890,181
Investing Activities				
Capital expenditures	-	(131,568)	(928,191)	(1,059,759)
Other	-	-	18,452	18,452
Net Cash (Used in) Investing Activities	-	(131,568)	(909,739)	(1,041,307)
Financing Activities				
Treasury stock issued	88,786	-	-	88,786
Issuance (payment) of debt, net	248,213	125,000	3,706	376,919
Common and preferred stock dividends paid	(251,502)	-		(251,502)
Other	10,582	-	2,264	12,846
Net intercompany accounts	(217,107)	(57,726)	274,833	-
Net Cash Provided by (Used in) Financing Activities	(121,028)	67,274	280,803	227,049
Net Increase in Cash and Cash Equivalents	$ -	$ -	$ 75,923	$ 75,923
Cash and Cash Equivalents at Beginning of Period	-	-	83,329	83,329
Cash and Cash Equivalents at End of Period	$ -	$ -	$ 159,252	$ 159,252

Note 13. Workforce Reduction Programs

As a result of the Eastern and ENI acquisitions, we implemented early retirement and severance programs in an effort to reduce our workforce. The early retirement program was completed in December 2000, at which time KeySpan recorded a charge of $51.4 million to reflect termination benefits related to employees who voluntarily elected early retirement. In addition, KeySpan recorded a $13.8 million liability associated with severance programs; Eastern and ENI had previously recorded an additional liability of $8.9 million. The combined liability, therefore, was $22.7 million. During the year ended December 31, 2001, we reduced this liability by $4.1 million as a result of lower than anticipated costs per employee and recorded a corresponding reduction to goodwill. During 2002, we paid $3.5 million for the program and, in total, $13.6 million was distributed to employees during the past two years. The remaining liability of $5.0 million was reversed and recorded to earnings in 2002.

Note 14. Shareholder Rights Plan

On March 30, 1999, our Board of Directors adopted a Shareholder Rights Plan (the "Plan") designed to protect shareholders in the event of a proposed takeover. The Plan creates a mechanism that would dilute the ownership interest of a potential unauthorized acquirer. The Plan establishes one preferred stock purchase "right" for each outstanding share of common stock to shareholders of record on April 14, 1999. Each right, when exercisable, entitles the holder to purchase 1/100th of a share of Series D Preferred Stock, at a price of $95.00. The rights generally become exercisable following the acquisition of more than 20 percent of our common stock without the consent of the Board of Directors. Prior to becoming exercisable, the rights are redeemable by the Board of Directors for $0.01 per right. If not so redeemed, the rights will expire on March 30, 2009.

Note 15. Subsequent Events (Unaudited)

KeySpan is currently analyzing proposals from interested investors to participate in the equity portion of a leveraged lease financing of a new 250 MW combined cycle electric generating facility located at the existing Ravenswood electric generating facility site. KeySpan is seeking to arrange for the lease to be consummated in late April to coincide with the commencement of full commercial operation of the new facility. At the closing, the new facility will be acquired by the lessor from our subsidiary, KeySpan Ravenswood, LLC, and simultaneously leased back to it. All obligations of our subsidiary under the lease will be unconditionally guaranteed by KeySpan. We anticipate that this lease transaction will generate cash proceeds equivalent to the fair market value of the facility, currently anticipated to be approximately $360 million. It is expected that the cash proceeds from this transaction will be used to redeem outstanding commercial paper. It is intended for this lease transaction to qualify as an operating lease under SFAS 98 "Accounting for Leases: Sale/Leaseback Transactions Involving Real Estate; Sales-Type Leases of Real Estate; Definition of the Lease Term; an Initial Direct Costs of Direct Financing Leases, an amendment of FASB Statements No.13, 66, 91 and a rescission of FASB Statement No. 26 and Technical Bulletin No. 79-11." The lease will have a term of approximately 35 years and operating lease expense is anticipated to be between $15 million to $17 million per year. Lease payments will fluctuate from year to year, but are substantially paid over the first 16 years.

On February 27, 2004 KeySpan and KeySpan Facilities Income Fund (the "Fund") announced that the Fund has entered into an agreement to sell 15.617 million units of the Fund at a price of $12.60 per unit for gross total proceeds of approximately CDN$196.8 million. The proceeds of the offering will be used to acquire a 35.91% interest in the business of KeySpan Energy Canada Partnership ("KeySpan Canada") from KeySpan. KeySpan will receive net proceeds of approximately CDN$186.3 million (or approximately US$139 million), after commissions and expenses. This offer is subject to regulatory approvals and is expected to close on or about April 1, 2004. After closing, the Fund's ownership in KeySpan Canada will increase from 39.1% to 75%. KeySpan's ownership of KeySpan Canada will decrease to approximately 25%.

Note 16. Supplemental Gas and Oil Disclosures (Unaudited)

This information includes amounts attributable to 100% of Houston Exploration and KeySpan Exploration and Production, LLC at December 31, 2003. Shareholders other than KeySpan had a minority interest of approximately 45% in Houston Exploration at December 31, 2003, 34% in 2002 and 33% in 2001. Gas and oil operations, and reserves, were located in the United States in all years.

Capitalized Costs Relating to Gas and Oil Producing Activities

	(In Thousands of Dollars)		
At December 31,	2003	2002	2001
Unproved properties not being amortized	$ 142,905	$ 110,623	$ 195,478
Properties being amortized - productive and nonproductive	2,429,891	1,917,287	1,590,014
Total capitalized costs	2,572,796	2,027,910	1,785,492
Accumulated depletion	(1,159,509)	(968,713)	(791,194)
Net capitalized costs	$ 1,413,287	$ 1,059,197	$ 994,298

Costs Incurred in Property Acquisition, Exploration and Development Activities

	(In Thousands of Dollars)		
At December 31,	2003	2002	2001
Acquisition of properties -			
Unproved properties	$ 61,484	$ 14,600	$ 31,718
Proved properties	171,297	90,004	85,435
Exploration	66,259	28,343	74,497
Development	170,493	139,108	191,927
Asset retirement obligation	31,858	-	-
Total costs incurred	$ 501,391	$ 272,055	$ 383,577

Costs included in development costs to develop proved undeveloped reserves for the years ended December 31, 2003, 2002 and 2001 were $49.4 million, $11.0 million and $19.9 million, respectively.

Results of Operations from Gas and Oil Producing Activities*

	(In Thousands of Dollars)		
At December 31,	2003	2002	2001
Revenues	$ 497,948	$ 356,233	$ 404,584
Production and lifting costs	63,591	44,822	37,574
Shipping and handling costs	10,388	9,450	7,850
Depletion	205,118	177,548	173,566
Total expenses	279,097	231,820	218,990
Income before taxes	218,851	124,414	185,594
Income taxes	76,598	42,519	64,118
Results of operations	$ 142,253	$ 81,895	$ 121,476

- (Excluding corporate overhead and interest costs)

Summary of Production and Lifting Costs

	(In Thousands of Dollars)		
At December 31,	2003	2002	2001
Pumping, gauging and other labor	$ 10,975	$ 7,846	$ 5,342
Compressors and other rental equipment	5,136	4,135	3,023
Property taxes and insurance	7,155	6,801	3,640
Transportation	2,329	2,131	3,162
Processing fees	2,354	3,078	2,267
Workover and well stimulation	5,225	2,348	1,478
Repairs, maintenance and supplies	3,735	2,972	2,204
Fuel and chemicals	3,109	2,582	1,424
Environmental, regulatory and other	7,614	3,307	3,639
Severance taxes	15,959	9,622	11,395
Total production and lifting costs	$ 63,591	$ 44,822	$ 37,574

The gas and oil reserves information is based on estimates of proved reserves attributable to the interest of Houston Exploration and KeySpan Exploration and Production, LLC as of December 31 for each of the years presented. These estimates principally were prepared by independent petroleum consultants. Proved reserves are estimated quantities of natural gas and crude oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reserve Quantity Information Natural Gas (MMcf)

At December 31,	2003	2002	2001
Proved Reserves			
Beginning of year	614,734	585,659	545,858
Revisions of previous estimates	(32,433)	(15,324)	(39,994)
Extensions and discoveries	140,632	105,798	86,401
Production	(100,130)	(107,507)	(90,754)
Purchases of reserves in place	89,380	48,777	84,148
Sales of reserves in place	-	(2,669)	-
Proved reserves - End of year (1)	712,183	614,734	585,659
Proved developed reserves			
Beginning of year	435,629	448,921	431,536
End of Year (2)	488,012	435,629	448,921

(1) Includes minority interest of 318,417, 208,516, and 188,077 in 2003, 2002, and 2001, respectively.

(2) Includes minority interest of 218,190, 148,811and 148,593 in 2003, 2002, and 2001, respectively.

Crude Oil, Condensate and Natural Gas Liquids (MBbls)

At December 31,	2003	2002	2001
Proved reserves			
Beginning of Year	9,548	10,234	7,912
Revisions of previous estimates	(3,542)	(5)	(289)
Extension and discoveries	117	342	3,061
Production	(1,514)	(1,025)	(536)
Purchases of reserves in place	3,753	483	115
Sales of reserves in place	-	(481)	(29)
Proved reserves - End of year (1)	8,362	9,548	10,234
Proved developed reserves			
Beginning of year	2,413	2,479	2,126
End of year (2)	4,273	2,413	2,479

(1) Includes minority interest of 3,739, 2,256 and 2,186 in 2003, 2002, and 2001, respectively.

(2) Includes minority interest of 1,910, 824 and 821 in 2003, 2002, and 2001, respectively.

The standardized measure of discounted future net cash flows was prepared by applying year-end prices of gas and oil to the proved reserves. The standardized measure does not purport, nor should it be interpreted, to present the fair value of gas and oil reserves of Houston Exploration or KeySpan Exploration and Production LLC. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Gas and Oil Reserves

	(In Thousands of Dollars)		
At December 31,	2003	2002	2001
Future cash flows	$ 4,375,781	$ 2,951,622	$ 1,580,077
Future costs-			
Production	(769,892)	(495,097)	(316,421)
Development	(378,547)	(263,926)	(227,158)
Future net inflows before income tax	3,227,342	2,192,599	1,036,498
Future income taxes	(853,425)	(559,853)	(221,324)
Future net cash flows	2,373,917	1,632,746	815,174
10% discount factor	(853,403)	(528,829)	(228,988)
Standardized measure of discounted future net cash flows (1)	$ 1,520,514	$ 1,103,917	$ 586,186

(1) Includes minority interest of $672,620, $361,435 and $182,555 in 2003, 2002 and 2001, respectively.

Costs included in future development costs related to proved undeveloped reserves for the years ending December 31, 2004, 2005 and 2006 are $96.3 million, $135.4 million, and $10.5 million, respectively.

Changes in Standardized Measure of Discounted Future Net Cash Flows from Proved Reserve Quantities

	(In Thousands of Dollars)		
At December 31,	2003	2002	2001
Standardized measure - beginning of year	$ 1,103,917	$ 586,186	$ 2,165,759
Sales and transfers, net of production costs	(492,328)	(285,603)	(359,163)
Net change in sales and transfer prices, net of production costs	384,299	589,632	(2,250,252)
Extensions and discoveries and improved recovery, net of related costs	434,311	242,055	117,326
Changes in estimated future development costs	(9,352)	(6,453)	(23,395)
Development costs incurred during the period that reduced future development costs	81,025	42,075	75,652
Revisions of quantity estimates	(123,954)	(36,368)	(52,928)
Accretion of discount	142,296	68,986	293,581
Net change in income taxes	(236,551)	(215,369)	666,373
Net purchases of reserves in place	254,030	99,741	51,674
Sales of reserves in place	-	(31,488)	(133)
Changes in production rates (timing) and other	(17,179)	50,523	(98,308)
Standardized measure - end of year	$ 1,520,514	$ 1,103,917	$ 586,186

Average Sales Prices and Production Costs Per Unit

Year Ended December 31,	2003	2002	2001
Average Sales Price*			
Natural gas ($/Mcf)	5.23	3.16	4.09
Oil, condensate and natural gas liquid ($/Bbl)	28.26	24.06	23.09
Production cost per equivalent Mcf ($)	0.58	0.42	0.40

*Represents the cash price received which excludes the effect of any hedging transactions.

Acreage

At December 31, 2003	Gross	Net
Producing	638,425	396,192
Undeveloped	464,874	388,830

Number of Producing Wells

At December 31, 2003	Gross	Net
Gas wells	2,435.0	1,748.0
Oil wells	31.0	15.9

Drilling Activity (Net)

At December 31,	2003			2002			2001		
	Producing	Dry	Total	Producing	Dry	Total	Producing	Dry	Total
Net developmental wells	84.4	20.0	104.4	65.1	9.4	74.5	51.9	10.2	62.1
Net exploratory wells	5.4	7.0	12.4	4.0	2.2	6.2	5.3	4.3	9.6

At December 31, 2003	Gross	Net
Exploratory	4.0	3.3
Developmental	12.0	9.2

Note 17. Summary of Quarterly Information (Unaudited)

The following is a table of financial data for each quarter of KeySpan's year ended December 31, 2003.

(In Thousands of Dollars, Except Per Share Amounts)	*Quarter Ended* 3/31/03	6/30/03	9/30/03	12/31/03
Operating revenues	2,512,525	1,408,152	1,131,814	1,862,670
Operating income	456,694	138,229	107,923	338,811
Earnings (loss) from continuing operations	243,091	(5,938)	12,585	174,443
Cumulative change in accounting principle	174	-	-	(37,625)
Earnings (loss) for common stock	241,804	(7,399)	11,124	135,357
Basic earnings per common share from continuing operations less preferred stock dividends (a)	1.54	(0.05)	0.07	1.08
Change in accounting principle (a)	-	-	-	(0.23)
Basic earnings per common share (a)	1.54	(0.05)	0.07	0.85
Diluted earnings per common share (a)	1.53	(0.05)	0.07	0.84
Dividends declared	0.445	0.445	0.445	0.445

(a) Quarterly earnings per share are based on the average number of shares outstanding during each quarter. Because of the changing number of common shares outstanding in each quarter, the sum of quarterly earnings per share does not necessarily equal earnings per share for the year.

The following is a table of financial data for each quarter of KeySpan's year ended December 31, 2002.

(In Thousands of Dollars, Except Per Share Amounts)	*Quarter Ended* 3/31/2002	6/30/2002	9/30/2002	12/31/2002
Operating revenues	1,873,577	1,218,201	1,078,336	1,800,552
Operating income	406,038	115,383	97,692	322,969
Earnings from continuing operations	214,631	29,174	4,964	148,581
Earnings (loss) from discontinued operations	-	(19,662)	-	-
Earnings for common stock	213,155	8,036	3,629	147,115
Basic earnings per common share from continuing operations less preferred stock dividends (a)	1.52	0.20	0.03	1.03
Basic earnings per common share from discontinued operations (a)	-	(0.14)	-	-
Basic earnings per common share (a)	1.52	0.06	0.03	1.03
Diluted earnings per common share (a)	1.51	0.06	0.02	1.03
Dividends declared	0.445	0.445	0.445	0.445

(a) Quarterly earnings per share are based on the average number of shares outstanding during each quarter. Because of the changing number of common shares outstanding in each quarter, the sum of quarterly earnings per share does not necessarily equal earnings per share for the year.

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors of KeySpan Corporation:

We have audited the accompanying Consolidated Balance Sheets of KeySpan Corporation and subsidiaries (the Company) as of December 31, 2003 and 2002, and the related Consolidated Statements of Income, Retained Earnings, Comprehensive Income, Capitalization, and Cash Flows for each of the two years in the period ended December 31, 2003. Our audits also included the consolidated financial statement schedule, for each of the two years in the period ended December 31, 2003, included in the Index in Item 15. These consolidated financial statements and the consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and the consolidated financial schedule based on our audits. The consolidated financial statements and consolidated financial statement schedule of KeySpan Corporation for the year ended December 31, 2001 were audited by other auditors who have ceased operations. Their report, dated February 4, 2002, expressed an unqualified opinion on those statements.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the KeySpan Corporation and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, such consolidated financial statement schedule, for each of the two years in the period ended December 31, 2003, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects, the information set forth therein.

As discussed in Note 1(G) to the consolidated financial statements, on January 1, 2002, the Company adopted Statement of Financial Accounting Standards ("SFAS") No. 142, "Goodwill and Other Intangible Assets," (SFAS No. 142) to change its method of accounting for goodwill and other intangibles. As discussed in Note 1(N) and Note 7, on January 1, 2003, the Company adopted SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure" and SFAS No. 143 "Accounting for Asset Retirement Obligations" (SFAS No. 143), respectively. Also, as discussed in Note 1(O), on December 31, 2003, the Company adopted FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51" (FIN 46).

As discussed above, the consolidated financial statements of the Company as of December 31, 2001 were audited by other auditors who have ceased operations. The notes related to these consolidated financial statements have been revised from those originally issued to include the transitional disclosures required by SFAS No. 142, SFAS No. 143 and FIN 46, which were adopted by the Company as of January 1, 2002, January 1, 2003 and December 31, 2003, respectively. Our audit procedures with respect to the disclosures in Note 1(G) for 2001 included (i) agreeing the previously reported earnings for common shareholders to the previously issued consolidated financial statements and the adjustments to earnings for common shareholders representing amortization expense recognized in those periods related to goodwill to the Company's underlying records obtained from management, and (ii) testing the mathematical accuracy of the reconciliation of adjusted net income to reported earnings for common shareholders, and the related earnings-per-share amounts. Our audit procedures with respect to the disclosures in Note 1(P) for 2001 included (i) agreeing the previously reported earnings for common stock to the previously issued consolidated financial statements and the adjustments to earnings for common stock representing accretion, cost of removal and amortization expense to the Company's underlying records obtained from management, and (ii) testing the mathematical accuracy of the reconciliation of Earnings for Common Stock to reported pro forma earnings, and the related earnings-per-share amounts.

In addition, the 2001 consolidated financial statements have also been revised from those originally issued to reflect certain reclassifications as discussed in Note 1(B). These reclassifications have been made to the Consolidated Statement of Income and the Consolidated Statement of Cash Flows. On the Consolidated Statement of Income, "Income from Equity Investments" has been reclassified from a component of "Other Income and (Deductions)" to a component of "Operating Income." On the Consolidated Statement of Cash Flows, "Net Income," "Minority Interest," "Changes in Assets and Liabilities – Other," and "(Gain) Loss on Disposal of Subsidiary Stock" amounts have been reclassified. Our audit procedures with respect to such reclassifications for 2001 included (i) agreeing the amount to the previously issued consolidated financial statements, and (ii) testing the mathematical accuracy of the consolidated financial statements.

In our opinion, the adjustments in Note 1(G), Note 1(P), and the reclassifications reflected in the Consolidated Statements of Income and Cash Flows are appropriate and have been properly applied. However, we were not engaged to audit, review, or apply any procedures to the 2001 financial statements of the Company other than with respect to such adjustments and reclassifications and, accordingly, we do not express an opinion or any other form of assurance on the 2001 financial statements taken as a whole.

/s/Deloitte & Touche LLP
February 18, 2004
New York, New York

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Shareholder and Board of Directors of KeySpan Corporation d/b/a KeySpan Energy:

We have audited the accompanying Consolidated Balance Sheet and Consolidated Statement of Capitalization of KeySpan Corporation (a New York corporation) and subsidiaries as of December 31, 2001 and December 31, 2000 and the related Consolidated Statements of Income, Retained Earnings, Comprehensive Income and Cash Flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of KeySpan Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position and capitalization of KeySpan Corporation and subsidiaries as of December 31, 2001 and December 31, 2000 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

Our audits were made for the purpose of forming an opinion on the basic financial statements taken as a whole. The schedule listed in Item 14 is the responsibility of the KeySpan Corporation's management and is presented for the purpose of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth in relation to the basic financial statements taken as a whole.

ARTHUR ANDERSEN LLP
February 4, 2002
New York, New York

Readers of these consolidated financial statements should be aware that this report is a copy of a previously issued Arthur Andersen LLP report and that this report has not been reissued by Arthur Andersen LLP. Furthermore, this report has not been updated since February 4, 2002 and Arthur Andersen LLP completed its last post-audit review of the December 31, 2001, consolidated financial information on April 29, 2002.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

Arthur Andersen LLP ("Arthur Andersen") served as KeySpan's independent public accountants since May 1998. On March 29, 2002, KeySpan's Board of Directors, upon recommendation of the Audit Committee, determined not to renew the engagement of Arthur Andersen and appointed Deloitte & Touche LLP ("Deloitte & Touche") as independent public accountants. During the past three fiscal years, there was no report on the financial statements of the Company by either Deloitte & Touche or Arthur Andersen that contained an adverse opinion or a disclaimer of opinion, or was qualified or modified as to uncertainty, audit scope, or accounting principles. During the past three fiscal years, there were no disagreements with either Deloitte & Touche or Arthur Andersen on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedure which, if not resolved to the satisfaction of either Deloitte & Touche or Arthur Andersen, would have caused the firm to make reference to the subject matter of such disagreements in connection with their respective reports.

Item 9A. *Controls and Procedures*

KeySpan maintains "disclosure controls and procedures", as such term is defined under Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed by KeySpan in the reports it files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and that such information is accumulated and communicated to KeySpan's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

An evaluation of the effectiveness of KeySpan's disclosure controls and procedures as of December 31, 2003 was conducted under the supervision and with the participation of KeySpan's Chief Executive Officer and Chief Financial Officer. Based on that evaluation, KeySpan's Chief Executive Officer and Chief Financial Officer have concluded that KeySpan's disclosure controls and procedures were adequate and designed to ensure that material information relating to KeySpan and its consolidated subsidiaries would be made known to the Chief Executive Officer and Chief Financial Officer by others within those entities, particularly during the periods when periodic reports under the Exchange Act are being prepared. Furthermore, there has been no change in KeySpan's internal control over financial reporting, identified in connection with the evaluation of such control, that occurred during KeySpan's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, KeySpan's internal control over financial reporting. Refer to the Certifications by KeySpan's Chief Executive Officer and Chief Financial Officer filed as exhibits 31.1 and 31.2 to this report.

PART III

Item 10. *Directors and Executive Officers of the Registrant*

A definitive proxy statement will be filed with the SEC on or about March 25, 2004 (the "Proxy Statement"). The information required by this item is set forth under the caption "Executive Officers of the Company" in Part I hereof and under the captions "Proposal 1. Election of Directors, Certain Relationships and Related Transactions", "Committees of the Board", "Code of Ethics" and "Section 16(a) Beneficial Ownership Reporting Compliance" contained in the Proxy Statement, which information is incorporated herein by reference thereto.

Item 11. *Executive Compensation*

The information required by this item set forth under the captions "Director Compensation" and "Executive Compensation" in the Proxy Statement, which information is incorporated herein by reference thereto.

Item 12. *Security Ownership of Certain Beneficial Owners and Management*

The information required by this item is set forth under the captions "Security Ownership of Management" and "Security Ownership of Certain Beneficial Owners" in the Proxy Statement, and in Item 5 of this report, which information is incorporated herein by reference thereto.

Item 13. *Certain Relationships and Related Transactions*

The information required by this item is set forth under the caption "Agreements with Executives" and "Certain Relationships and Related Transactions" in the Proxy Statement, which information is incorporated by reference thereto.

Item 14. *Principal Accounting Fees and Services*

The information required by this item is set forth under the caption "Proposal 2. Ratification of Deloitte & Touche LLP as Independent Public Accountants," "Fiscal Year 2003 Audit Firm Fee Summary" and "Report of the Audit Committee" in the Proxy Statement, which information is incorporated by reference thereto.

Item 15. *Exhibits, Financial Statement Schedules and Reports on Form 8-K*

(a) Required Documents

1. Financial Statements

The following consolidated financial statements of KeySpan and its subsidiaries and report of independent accountants are included in Item 8 and are filed as part of this Report:

- Consolidated Statement of Income for the year ended December 31, 2003, the year ended December 31, 2002, and the year ended December 31, 2001

- Consolidated Statement of Retained Earnings for the year ended December 31, 2003, the year ended December 31, 2002, and the year ended December 31, 2001
- Consolidated Balance Sheet at December 31, 2003 and December 31, 2002
- Consolidated Statement of Capitalization at December 31, 2003 and December 31, 2002
- Consolidated Statement of Cash Flows for the year ended December 31, 2003, the year ended December 31, 2002, and the year ended December 31, 2001
- Consolidated Statement of Comprehensive Income for the Year ended December 31, 2003, the year ended December 31, 2002 and the year ended December 31, 2001
- Notes to Consolidated Financial Statements
- Independent Auditor's Report

2. Financial Statement Schedules

Consolidated Schedule of Valuation and Qualifying Accounts for the year ended December 31, 2003, the year ended December 31, 2002, and the year ended December 31, 2001.

SCHEDULE OF VALUATION AND QUALIFYING ACCOUNTS

Column A	Column B	Column C Additions		Column D	Column E
Descriptions	Balance at Beginning of Period	Charged to costs and expenses	Acquisitions	Net Deductions	Balance at End of Period
Twelve Months Ended December 31, 2003					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 63,029	$ 82,120	$ -	$ 65,965	$ 79,184
Additions to liability accounts:					
Reserve for injury and damages	$ 25,780	$ 3,928	$ -	$ 20,338	$ 9,370
Reserve for environmental expenditures	$ 232,146	$ 106,270	$ -	$ 43,725	$ 294,691
Twelve Months Ended December 31, 2002					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 72,299	$ 58,939	$ -	$ 68,209	$ 63,029
Additions to liability accounts:					
Reserve for injury and damages	$ 20,880	$ 11,984	$ -	$ 7,084	$ 25,780
Reserve for environmental expenditures	$ 257,649	$ -	$ -	$ 25,503	$ 232,146
Twelve Months Ended December 31, 2001					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 48,314	$ 66,500	$ -	$ 42,515	$ 72,299
Additions to liability accounts:					
Reserve for injury and damages	$ 40,700	$ 7,643	$ -	$ 27,463	$ 20,880
Reserve for environmental expenditures	$ 157,507	$ 115,942	$ -	$ 15,800	$ 257,649

All other schedules are omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

(b) Reports on Form 8-K

In our report on Form 8-K dated November 6, 2003, we disclosed that we issued a press release concerning, among other things, our earnings for the third quarter ended September 30, 2003.

In our report on Form 8-K dated December 18, 2003, we disclosed that we issued a press release disclosing, among other things, our expectations for 2004 earnings.

In our report on Form 8-K dated February 5, 2004, we disclosed that we issued a press release concerning, among other things, our consolidated earnings for the year ended December 31, 2003.

(c) Exhibits

Exhibits listed below which have been filed with the SEC pursuant to the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, and which were filed as noted below, are hereby incorporated by reference and made a part of this report with the same effect as if filed herewith.

2 Purchase Agreement by and among Eastern Enterprises, Landgrove Corp. and KeySpan Corporation for the acquisition of Midland Enterprises dated as of January 23, 2002 (filed as Exhibit 2 to the Company's Form 10-K for the year ended December 31, 2001)

3.1 Certificate of Incorporation of the Company effective April 16, 1998, Amendment to Certificate of Incorporation of the Company effective May 26, 1998, Amendment to Certificate of Incorporation of the Company effective June 1, 1998, Amendment to the Certificate of Incorporation of the Company effective April 7, 1999 and Amendment to the Certificate of Incorporation of the Company effective May 20, 1999 (filed as Exhibit 3.1 to the Company's Form 10-Q for the quarterly period ended June 30, 1999)

3.2 ByLaws of the Company in effect as of June 25, 2003, as amended (filed as Exhibit 3.1 to the Company's Form 10-Q for the quarterly period ended June 30, 2003)

4.1-a Indenture, dated as of November 1, 2000, between KeySpan Corporation and the Chase Manhattan Bank, as Trustee, with respect to the issuance of Debt Securities (filed as Exhibit 4-a to Amendment No. 1 to Form S-3 Registration Statement No. 333-43768 and filed as Exhibit 4-a to the Company's Form 8-K on November 20, 2000)

4.1-b Form of Note issued in connection with the issuance of the 7.25% notes issued on November 20, 2000 (filed as Exhibit 4-b to the Company's Form 8-K on November 20, 2000)

4.1-c Form of Note issued in connection with the issuance of the 7.625% notes issued on November 20, 2000 (filed as Exhibit 4-c to the Company's Form 8-K on November 20, 2000)

4.1-d Form of Note issued in connection with the issuance of the 8.0% notes issued on November 20, 2000 (filed as Exhibit 4-d to the Company's Form 8-K on November 20, 2000)

4.1-e Form of Note issued in connection with the issuance of the 6.15% notes issued on May 24, 2001 (filed as Exhibit 4 to the Company's Form 8-K on May 24, 2001)

4.2-a Indenture, dated December 1, 1999, between KeySpan and KeySpan Gas East Corporation, the Registrants, and the Chase Manhattan Bank, as Trustee, with respect to the issuance of Medium-Term Notes, Series A, (filed as Exhibit 4-a to Amendment No. 1 to the Company's and KeySpan Gas East Corporation's Form S-3 Registration Statement No. 333-92003)

4.2-b Form of Medium-Term Note issued in connection with the issuance of KeySpan Gas East Corporation 7 7/8% notes issued on February 1, 2000 (filed as Exhibit 4 to the Company's Form 8-K on February 1, 2000)

4.2-c Form of Medium-Term Note issued in connection with the issuance of KeySpan Gas East Corporation 6.9% notes issued on January 19, 2001 (filed as Exhibit 4.3 to the Company's Form 10-K for the year ended December 31, 2000)

4.3 Credit Agreement among KeySpan Corporation, the several Lenders, ABN AMRO Bank, N.V., as Syndication Agent, Bank One, N. A. and Wachovia Bank, N.A, as Co-Documentation Agents, and J.P. Morgan Chase Bank, as Administrative Agent for $450 million, dated as of June 27, 2003 (filed as Exhibit 4.1 to the Company's Form 10-Q for the quarterly period ended June 30, 2003)

4.4 Credit Agreement among KeySpan Corporation, the several Lenders, Citibank N.A., as Syndication Agent, Bank of New York and The Royal Bank of Scotland PLC, as Co-Documentation Agents, and J.P. Morgan Chase Bank, as Administrative Agent for $850 million, dated as of June 27, 2003 (filed as Exhibit 4.1 to the Company's Form 10-Q for the quarterly period ended June 30, 2003)

4.5-a Participation Agreements dated as of February 1, 1989, between NYSERDA and The Brooklyn Union Gas Company relating to the Adjustable Rate Gas Facilities Revenue Bonds ("GFRBs") Series 1989A and Series 1989B (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1989)

4.5-b Indenture of Trust, dated February 1, 1989, between NYSERDA and Manufacturers Hanover Trust Company, as Trustee, relating to the Adjustable Rate GFRBs Series 1989A and 1989B (filed as Exhibit 4 to the Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1989)

4.5-c First Supplemental Participation Agreement dated as of May 1, 1992 to Participation Agreement dated February 1, 1989 between NYSERDA and The Brooklyn Union Gas Company relating to Adjustable Rate GFRBs, Series 1989A & B (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1992)

4.5-d First Supplemental Trust Indenture dated as of May 1, 1992 to Trust Indenture dated February 1, 1989 between NYSERDA and Manufacturers Hanover Trust Company, as Trustee, relating to Adjustable Rate GFRBs, Series 1989A & B (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1992)

4.6-a Participation Agreement, dated as of July 1, 1991, between NYSERDA and The Brooklyn Union Gas Company relating to the GFRBs Series 1991A and 1991B (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1991)

4.6-b Indenture of Trust, dated as of July 1, 1991, between NYSERDA and Manufacturers Hanover Trust Company, as Trustee, relating to the GFRBs Series 1991A and 1991B (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1991)

4.7-a Participation Agreement, dated as of July 1, 1992, between NYSERDA and The Brooklyn Union Gas Company relating to the GFRBs Series 1993A and 1993B (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1992)

4.7-b Indenture of Trust, dated as of July 1, 1992, between NYSERDA and Chemical Bank, as Trustee, relating to the GFRBs Series 1993A and 1993B (filed as Exhibit 4 to The Brooklyn Union Gas Company Form 10-K for the year ended September 30, 1992)

4.8-a First Supplemental Participation Agreement dated as of July 1, 1993 to Participation Agreement dated as of June 1, 1990, between NYSERDA and The Brooklyn Union Gas Company relating to GFRBs Series C (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1993)

4.8-b First Supplemental Trust Indenture dated as of July 1, 1993 to Trust Indenture dated as of June 1, 1990 between NYSERDA and Chemical Bank, as Trustee, relating to GFRBs Series C (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1993)

4.9-a Participation Agreement, dated July 15, 1993, between NYSERDA and Chemical Bank as Trustee, relating to the GFRBs Series D-1 1993 and Series D-2 1993 (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form S-8 Registration Statement No. 33-66182)

4.9-b Indenture of Trust, dated July 15, 1993, between NYSERDA and Chemical Bank as Trustee, relating to the GFRBs Series D-1 1993 and D-2 1993 (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form S-8 Registration Statement No. 33-66182)

4.10-a Participation Agreement, dated January 1, 1996, between NYSERDA and The Brooklyn Union Gas Company relating to GFRBs Series 1996 (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1996)

4.10-b Indenture of Trust, dated January 1, 1996, between NYSERDA and Chemical Bank, as Trustee, relating to GFRBs Series 1996 (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1996)

4.11-a Participation Agreement, dated as of January 1, 1997, between NYSERDA and The Brooklyn Union Gas Company relating to GFRBs 1997 Series A (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1997)

4.11-b Indenture of Trust, dated January 1, 1997, between NYSERDA and Chase Manhattan Bank, as Trustee, relating to GFRBs 1997 Series A (filed as Exhibit 4 to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1997)

4.11-c Supplemental Trust Indenture, dated as of January 1, 2000, by and between New York State NYSERDA and The Chase Manhattan Bank, as Trustee, relating to the GFRBs 1997 Series A (filed as Exhibit 4.11 to the Company's Form 10-K for the year ended December 31, 1999)

4.12-a Participation Agreement dated as of December 1, 1997 by and between NYSERDA and Long Island Lighting Company relating to the 1997 EFRBs, Series A (filed as Exhibit 10(a) to the Company's Form 10-Q for the quarterly period ended September 30, 1998)

4.12-b Indenture of Trust dated as of December 1, 1997 by and between NYSERDA and The Chase Manhattan Bank, as Trustee, relating to the 1997 Electric Facilities Revenue Bonds (EFRBs), Series A (filed as Exhibit 10(a) to the Company's Form 10-Q for the quarterly period ended September 30, 1998)

4.13-a Participation Agreement, dated as of October 1, 1999, by and between NYSERDA and KeySpan Generation LLC relating to the 1999 Pollution Control Refunding Revenue Bonds, Series A (filed as Exhibit 4.10 to the Company's Form 10-K for the year ended December 31, 1999)

4.13-b Trust Indenture, dated as of October 1, 1999, by and between NYSERDA and The Chase Manhattan Bank, as Trustee, relating to the 1999 Pollution Control Refunding Revenue Bonds, Series A (filed as Exhibit 4.10 to the Company's Form 10-K for the year ended December 31, 1999)

4.14-a* Lease Agreement, dated as of November 1, 2003, by and between the Suffolk County Industrial Development Agency and KeySpan-Port Jefferson Energy Center, LLC

4.14-b* Company Lease Agreement, dated as of November 1, 2003, by and between KeySpan-Port Jefferson Energy Center, LLC and the Suffolk County Industrial Development Agency

4.14-c* Guaranty, dated as of November 26, 2003, from KeySpan Corporation to the Suffolk County Industrial Development Agency

4.15-a* Lease Agreement, dated as of November 1, 2003, by and between the Nassau County Industrial Development Agency and KeySpan-Glenwood Energy Center, LLC

4.15-b* Company Lease Agreement, dated as of November 1, 2003, by and between KeySpan-Glenwood Energy Center, LLC and the Nassau County Industrial Development Agency

4.15-c* Guaranty, dated as of November 26, 2003, from KeySpan Corporation to the Nassau County Industrial Development Agency

4.16 Indenture dated as of December 1, 1989 between Boston Gas Company and The Bank of New York, Trustee (filed as Exhibit 4.2 to Boston Gas Company's Form S-3 (File No. 33-31869))

4.17 Agreement of Registration, Appointment and Acceptance dated as of November 18, 1992 among Boston Gas Company, The Bank of New York as Resigning Trustee, and The First National Bank of Boston as Successor Trustee (filed as an Exhibit to Boston Gas Company's S-3 Registration Statement (File No. 33-31869))

4.18 Second Amended and Restated First Mortgage Indenture for Colonial Gas Company dated as of June 1, 1992 (filed as Exhibit 4(b) to Colonial Gas Company's Form 10-Q for the quarter ended June 30, 1992)

4.19 First Supplemental Indenture for Colonial Gas Company dated as of June 15, 1992 (filed as Exhibit 4(c) to Colonial Gas Company's Form 10-Q for the quarter ended June 30, 1992)

4.20 Second Supplemental Indenture for Colonial Gas Company dated as of September 27, 1995 (filed as Exhibit 4(c) to Colonial Gas Company's Form 10-K for the fiscal year ended December 31, 1995)

4.21 Amendment to Second Supplemental Indenture for Colonial Gas Company dated as of October 12, 1995 (filed as Exhibit 4(d) to Colonial Gas Company's Form 10-K for the fiscal year ended December 31, 1995)

4.22 Third Supplemental Indenture for Colonial Gas Company dated as of December 15, 1995 (filed as Exhibit 4(f) to Colonial Gas Company's Form S-3 Registration Statement dated January 5, 1998)

4.23 Fourth Supplemental Indenture for Colonial Gas Company dated as of March 1, 1998 (filed as Exhibit 4(l) to Colonial Gas Company's Form 10-Q for the quarter ended March 31, 1998)

4.24 Trust Agreement dated as of June 22, 1990 between Colonial Gas Company (as Trustor) and Shawmut Bank, N.A. (as Trustee) (filed as Exhibit 10(d) to Colonial Gas Company's Form 10-Q for the period ended June 30, 1990)

4.25 Gas Service, Inc. General and Refunding Mortgage Indenture, dated as of June 30, 1987, as amended and supplemented by a First Supplemental Indenture, dated as of October 1, 1988, and by a Second Supplemental Indenture, dated as of August 31, 1989 (filed as Exhibit 4.1 to EnergyNorth Natural Gas, Inc.'s Form 10-K for the fiscal year ended September 30, 1989 (File No. 0-11035))

4.26 Third Supplemental Indenture, dated as of September 1, 1990, to Gas Service, Inc.'s General and Refunding Mortgage Indenture, dated as of June 30, 1987 (filed as Exhibit 4.2 to EnergyNorth Natural Gas, Inc.'s Form 10-K for the fiscal year ended September 30, 1990 (File No. 0-11035))

4.27 Fourth Supplemental Indenture, dated as of January 10, 1992, to Gas Service, Inc.'s General and Refunding Mortgage Indenture, dated as of June 30, 1987 (filed as Exhibit 4.3 of EnergyNorth Natural Gas, Inc.'s Form 10-K for the fiscal year ended September 30, 1992 (File No. 0-11035))

4.28 Fifth Supplemental Indenture, dated as of February 1, 1995, to Gas Service, Inc.'s General and Refunding Mortgage Indenture, dated as of June 30, 1987 (filed as Exhibit 4.4 to EnergyNorth Natural Gas, Inc.'s Form 10-K for the fiscal year ended September 30, 1996 (File No. 1-11441))

4.29 Sixth Supplemental Indenture, dated as of September 15, 1997, to Gas Service, Inc.'s General and Refunding Mortgage Indenture, dated as of June 30, 1987 (filed as Exhibit 4.5 to EnergyNorth Natural Gas, Inc.'s Amendment No. 1 to Registration Statement on Form S-1, No. 333-32949, dated September 10, 1997)

4.30 Indenture dated as of June 1, 1986 between Essex Gas Company and Centerre Trust Company of St. Louis, Trustee (filed as an Exhibit to Essex Gas Company's Registration Statement on Form S-2, filed June 19, 1986 (File No. 33-6597))

4.31 Twelfth Supplemental Indenture dated as of December 1, 1990, between Essex Gas Company and Centerre Trust Company of St. Louis, Trustee, providing for a 10.10% Series due 2020 (filed as Exhibit 4-14 to Essex Gas Company's Form 10-Q for the quarter ended February 28, 1991)

4.32 Fifteenth Supplemental Indenture dated as of December 1, 1996, between Essex Gas Company and Centerre Trust Company of St. Louis, Trustee, providing for a 7.28 % Series due 2017 (filed as Exhibit 4.5 to the Essex Gas Company's Form 10-Q for the quarter ended February 28, 1997)

4.33 Bond Purchase Agreement dated December 1, 1990, between Allstate Life Insurance Company of New York and Essex County Gas Company (filed as an Exhibit to Essex Gas Company's Form 10-Q for the quarter ended February 28, 1991)

4.34* Letter of Credit and Reimbursement Agreement dated December 9, 2003, by and between KeySpan Generation LLC and Royal Bank of Scotland Bank PLC

4.35 Indenture, dated as of March 2, 1998, between The Houston Exploration Company and The Bank of New York, as Trustee, with respect to the 8 5/8% Senior Subordinated Notes Due 2008 (including form of 8 5/8% Senior Subordinated Note Due 2008) (filed as Exhibit 4.1 to The Houston Exploration Company's Registration Statement on Form S-4 (No. 333-50235))

4.36 Indenture, dated as of June 10, 2003, between The Houston Exploration Company and the Bank of New York, as Trustee, with respect to the 7% Senior Subordinated Notes due 2013. (filed as Exhibit 4.2 to The Houston Exploration Company's Registration Statement on Form S-4 (No. 333-106836)

10.1 Amendment, Assignment and Assumption Agreement dated as of September 29, 1997 by and among The Brooklyn Union Gas Company, Long Island Lighting Company and KeySpan Energy Corporation (filed as Exhibit 2.5 to Schedule 13D by Long Island Lighting Company on October 24, 1997)

10.2 Agreement and Plan of Merger dated as of June 26, 1997 by and among BL Holding Corp., Long Island Lighting Company, Long Island Power Authority and LIPA Acquisition Corp. (filed as Annex D to Registration Statement on Form S-4, No. 333-30353 on June 30, 1997)

10.3 Agreement of Lease between Forest City Jay Street Associates and The Brooklyn Union Gas Company dated September 15, 1988 (filed as an Exhibit to The Brooklyn Union Gas Company's Form 10-K for the year ended September 30, 1996)

10.4-a Management Services Agreement between Long Island Power Authority and Long Island Lighting Company dated as of June 26, 1997 (filed as Annex D to Registration Statement on Form S-4, No. 333-30353, on June 30, 1997)

10.4-b Amendment dated as of March 29, 2002 to Management Services Agreement between Long Island Lighting Company d/b/a LIPA and KeySpan Electric Services LLC dated as of June 26, 1997 (filed as Exhibit 10.4-b to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)

10.5 Power Supply Agreement between Long Island Lighting Company and Long Island Power Authority dated as of June 26, 1997 (filed as Annex D to Registration Statement on Form S-4, No. 333-30353, on June 30, 1997)

10.6-a Energy Management Agreement between Long Island Lighting Company and Long Island Power Authority dated as of June 26, 1997 (filed as Annex D to Registration Statement on Form S-4, No. 333-30353, on June 30, 1997)

10.6-b Amendment dated as of March 29, 2002 to Energy Management Agreement between Long Island Lighting Company d/b/a LIPA and KeySpan Energy Trading Services LLC dated as of June 26, 1997 (filed as Exhibit 10.6-b to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)

10.7-a Generation Purchase Rights Agreement between Long Island Lighting Company and Long Island Power Authority dated as of June 26, 1997 (filed as Exhibit 10.17 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001)

10.7-b Amendment dated as of March 29, 2002 to Generation Purchase Right Agreement by and between KeySpan Corporation as Seller, and Long Island Lighting Company d/b/a LIPA as Buyer, dated as of June 26, 1997 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002)

10.8** Employment Agreement dated September 10, 1998, between KeySpan and Robert B. Catell (filed as Exhibit (10)(b) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1998)

10.9** First Amendment dated as of February 24, 2000, to the Employment Agreement dated September 10, 1998, between KeySpan and Robert B. Catell (filed as Exhibit 10.12-a to the Company's Annual Report on Form 10-K for the year ended December 31, 2000)

10.10** Second Amendment dated as of June 26, 2002, to the Employment Agreement dated September 10, 1998, between KeySpan and Robert B. Catell (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2002)

10.11** Supplemental Retirement Agreement dated July 1, 2002 between KeySpan and Gerald Luterman (filed as Exhibit 10.11 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)

10.12** Supplemental Retirement Agreement dated July 1, 2002 between KeySpan and Steven L. Zelkowitz (filed as Exhibit 10.12 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)

10.13** Supplemental Retirement Agreement dated July 1, 2002 between KeySpan and David J. Manning (filed as Exhibit 10.13 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)

10.14** Supplemental Retirement Agreement dated July 1, 2002 between KeySpan and Neil Nichols (filed as Exhibit 10.14 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)

10.15** Supplemental Retirement Agreement dated July 1, 2002 between KeySpan and Elaine Weinstein (filed as Exhibit 10.15 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)

10.16** * Directors' Deferred Compensation Plan effective April 2003

10.17** Officers' Deferred Stock Unit Plan of KeySpan Corporation (filed as Exhibit 10.17 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)

10.18** Officers' Deferred Stock Unit Plan KeySpan Services, Inc. (filed as Exhibit 10.18 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)

10.19** Corporate Annual Incentive Compensation and Gainsharing Plan (filed as Exhibit 10.20 to the Company's Form 10-K for the year ended December 31, 2000)

10.20** * Senior Executive Change of Control Severance Plan effective as of October 29, 2003

10.21** KeySpan's Amended Long Term Performance Incentive Compensation Plan (filed as Exhibit A to the Company's 2001 Proxy Statement filed on March 23, 2001)

10.22 Rights Agreement dated March 30, 1999, between the KeySpan and the Rights Agent (filed as Exhibit 4 to the Company's Form 8-K filed on March 30, 1999)

10.23 Generating Plant and Gas Turbine Asset Purchase and Sale Agreement for the Ravenswood Generating Plants and Gas Turbines dated January 28, 1999, between the Company and Consolidated Edison Company of New York, Inc. (filed as Exhibit 10(a) to the Company's Form 10-Q for the quarterly period ended March 31, 1999)

10.24 Lease Agreement dated June 9, 1999, between KeySpan-Ravenswood, LLC and LIC Funding, Limited Partnership (filed as Exhibit 10.2 to the Company's Form 10-Q for the quarterly period ended June 30, 1999)

10.25 First Amendment to the Lease Agreement between KeySpan-Ravenswood, LLC and LIC Funding, Limited Partnership, dated as of June 27, 2002 (filed as Exhibit 10.25 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)

10.26 Guaranty dated June 9, 1999, from KeySpan in favor of LIC Funding, Limited Partnership (filed as Exhibit 10.1 to the Company's Form 10-Q for the quarterly period ended June 30, 1999)

10.27 Purchase Agreement by and among Duke Energy Gas Transmission Corporation, Algonquin Energy, Inc., KeySpan LNG GP, LLC and KeySpan LNG LP, dated as of December 12, 2002 (filed as Exhibit 10.27 to the Company's Annual Report on Form 10-K for the year ended December 31, 2002)

10.28 Restated Exploration Agreement between The Houston Exploration Company and KeySpan Exploration and Production, L.L.C., dated June 30, 2000, (filed as Exhibit 10.1 to The Houston Exploration Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2000, File No. 001-11899)

10.29-a Revolving Credit Facility between The Houston Exploration Company and Wachovia Bank, National Association, as issuing bank and administrative agent, Bank of Nova Scotia and Fleet National Bank as co-syndication agents and BNP Paribas as documentation agent dated July 15, 2002 (filed as Exhibit 10.1 to The Houston Exploration Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 001-11899)

10.29-b First Amendment to Credit Agreement among The Houston Exploration Company, the lenders Wachovia Bank, National Association, as issuing bank and as administrative agent, The Bank of Nova Scotia and Fleet National Bank, as co-syndication agents; and BNP Paribas, as documentation agent, effective June 5, 2003 (filed as Exhibit 10.1 to The Houston Exploration Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 001-11899)).

10.29-c Second Amendment to Credit Agreement among The Houston Exploration Company, the lenders named therein, Wachovia Bank, National Association, as issuing bank and as administrative agent, The Bank of Nova Scotia and Fleet National Bank, as co-syndication agents; and BNP Paribas, as documentation agent, effective September 3, 2003 (filed as Exhibit 10.1 to The Houston Exploration Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003 (File No. 001-11899)).

10.30-a Credit Agreement among KeySpan Energy Development Co. several Lenders and the Royal Bank of Canada, as Agent, for $125,000,000 (Canadian) Credit Facility, dated as of October 13, 2000 (filed as Exhibit 10.10 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001)

10.30-b Consent, Waiver and Amending Agreement among KeySpan Energy Development Co., several Lenders and the Royal Bank of Canada, as Agent, for the $125,000,000 (Canadian) Credit Facility, dated as of December 22, 2000 (filed as Exhibit 10.11 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001)

10.30-c Second Amending Agreement among KeySpan Energy Development Co., several Lenders and the Royal Bank of Canada, as Agent, for the $125,000,000 (Canadian)

Credit Facility, dated as of October 12, 2001 (filed as Exhibit 10.12 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001)

10.30-d Extendible Revolving Credit Facility Amended and Restated Credit Agreement among KeySpan Energy Development Co., National Bank Financial, ATB Financial and Certain Financial Institutions with National Bank of Canada, dated as of January 24, 2003

10.31-a Credit Agreement among KeySpan Energy Development Co., Borrower, the Several Lenders' and Royal Bank of Canada, Administrative Agent, dated July 29, 1999 (filed as Exhibit 10.37-a to the Company's Annual Report on Form 10-K for the year ended December 31, 2001)

10.31-b First Amending Agreement dated as of October 13, 2000 to the Credit Agreement among KeySpan Energy Development Co., Borrower, the Several Lenders' and Royal Bank of Canada, Administrative Agent dated July 29, 1999 (filed as Exhibit 10.37-b to the Company's Annual Report on Form 10-K for the year ended December 31, 2001)

10.31-c Second Amending Agreement dated as of December 15, 2000 to the Credit Agreement among KeySpan Energy Development Co., Borrower, the Several Lenders' and Royal Bank of Canada, Administrative Agent dated July 29, 1999 (filed as Exhibit 10.37-c to the Company's Annual Report on Form 10-K for the year ended December 31, 2001)

10.31-d Third Amending Agreement dated as of December 20, 2002 to the Credit Agreement among KeySpan Energy Development Co., Borrower, the Several Lenders' and Royal Bank of Canada, Administrative Agent dated July 29, 1999

10.32 Guarantee Agreement by KeySpan Corporation in favor of the Several Lenders to KeySpan Energy Development Co. dated as of July 29, 1999 (filed as Exhibit 10.38 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001)

10.33 Registration Rights Agreement dated as of July 2, 1996 between The Houston Exploration Company and THEC Holdings Corp. (filed as Exhibit 10.13 to The Houston Exploration Company's Registration Statement on Form S-1 (Registration No. 333-4437))

10.34 Registration Rights Agreement between The Houston Exploration Company and Smith Offshore Exploration Company (filed as Exhibit 10.15 to The Houston Exploration Company's Registration Statement on Form S-1 (Registration No. 333-4437))

10.35 Registration Rights Agreement dated as of June 5, 2003, among The Houston Exploration Company and Wachovia Securities, Inc., Lehman Brothers Inc., BNP Paribas Securities Corp., Fleet Securities, Inc. and Scotia Capital (USA) Inc., as

Initial Purchasers. (Exhibit 4.5 to The Houston Exploration Company's Registration Statement on Form S-4 (Registration No. 333-106836))

12*	Computation in support of ratio of earnings to fixed charges and ratio of combined fixed charges and dividends.
14*	Code of Ethics
21*	Subsidiaries of the Registrant
23.1*	Consent of Deloitte & Touche LLP, Independent Auditors
23.2*	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Consultants
23.3*	Consent of Miller and Lents, Ltd., Independent Petroleum Consultants
24.1*	Power of Attorney executed by Andrea S. Christensen on March 10, 2004
24.2*	Power of Attorney executed by Alan H. Fishman on March 10, 2004
24.3*	Power of Attorney executed by J. Atwood Ives on March 10, 2004
24.4*	Power of Attorney executed by James R. Jones on March 10, 2004
24.5*	Power of Attorney executed by James L. Larocca on March 10, 2004
24.6*	Power of Attorney executed by Gloria C. Larson on March 10, 2004
24.7*	Power of Attorney executed by Stephen W. McKessy on March 10, 2004
24.8*	Power of Attorney executed by Edward D. Miller on March 10, 2004
24.9*	Certified copy of the Resolution of the Board of Directors authorizing signatures pursuant to power of attorney
31.1*	Certification of the Chairman and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of the Executive Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of the Chairman and Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of the Executive Vice President and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

* filed herewith
** compensation agreement

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed by the registrant and on behalf of the registrant by the following persons in the capacities indicated.

KEYSPAN CORPORATION

By:/s/ Robert B. Catell
Robert B. Catell
Chairman of the Board of
Directors and
Chief Executive Officer

Robert B. Catell	Chairman of the Board of Directors and Chief Executive Officer
By:/s/ Robert B. Catell	
Gerald Luterman	Executive Vice President and Chief Financial Officer
By:/s/ Gerald Luterman	
Joseph F. Bodanza	Senior Vice President and Chief Accounting Officer
By:/s/ Joseph F. Bodanza	
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Andrea S. Christensen	Director

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Alan H. Fishman Director

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J. Atwood Ives Director

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James R. Jones Director

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Gloria C. Larson Director

*

____
James L. Larocca Director

*

____
Stephen W. McKessy Director

*

____
Edward D. Miller Director

____
Vikki Pryor Director

By:/s/ Gerald Luterman
Attorney-in-Fact

* Such signature has been affixed pursuant to a Power of Attorney filed as an exhibit hereto and incorporated herein by reference thereto