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Energy East Corporation

Annual Report 2004

Financial Highlights

Per Common Share	2004	2003	% Change
Earnings, basic	**$1.57**	$1.45	8
Earnings, diluted	**$1.56**	$1.44	8
Dividends Paid	**$1.055**	$1.00	6
Book Value at Year End	**$17.89**	$17.57	2
Price at Year End	**$26.68**	$22.40	19
Other Common Stock Information (Thousands)			
Average Common Shares Outstanding, basic	**146,305**	145,535	1
Average Common Shares Outstanding, diluted	**146,713**	145,730	1
Common Shares Outstanding at Year End, basic	**147,118**	146,262	1
Operating Results (Thousands)			
Total Operating Revenues	**$4,756,692**	$4,514,490	5
Total Operating Expenses	**$4,006,739**	$3,862,678	4
Net Income	**$229,337**	$210,446	9
Energy Distribution:			
Megawatt-hours			
Retail Deliveries	**31,019**	30,593	1
Wholesale Deliveries	**7,855**	5,734	37
Dekatherms			
Retail Deliveries	**208,444**	212,745	(2)
Wholesale Deliveries	**1,593**	5,360	(70)
Total Assets at Year End (Thousands)	**$10,796,113**	$11,330,441	(5)

March 2005

Dear Shareholders:

In 2004 we increased your common stock dividend 10% and improved our credit ratings. We also continued to enhance our leadership position in the Northeast energy market. In fact, in a J.D. Power and Associates study released this month, Energy East was recognized as one of the top utilities in the eastern United States for customer satisfaction.

Studies suggest that solid corporate performance, like Energy East's, is linked to effective corporate governance. The premise is a simple one. Companies that practice sound corporate governance and transparent financial reporting will, over time, produce shareholder value. In last year's Annual Report, I discussed our excellent corporate governance rating and noted that corporate governance is a part of everyday life at Energy East. In 2004 we made additional governance improvements, including submitting a proposal for the annual election of directors, which was overwhelmingly approved by shareholders. According to an independent survey on corporate governance, Energy East now outperforms over 90% of Standard & Poor's 400 companies.

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In addition to sound corporate governance, long-term rate agreements have been a key building block of Energy East's success. Last year, the New York State Public Service Commission approved five-year, electric and natural gas Performance Based Rate (PBR) plans for Rochester Gas & Electric (RG&E). All of our utilities now operate under long-term PBR plans. Those plans are important because they establish an earnings-sharing mechanism that allows both customers and shareholders to benefit from efficiencies we achieve at our utilities.

Our deliberate and systematic approach to integrating our six utility companies continues to meet or exceed expectations. Having completed the consolidation of "back office" functions such as accounting, finance, and information technology, we have now turned our focus to several "front office" initiatives. This spring we will introduce a new Work Management system throughout Energy East, and early next year a technologically advanced Customer Care system will be rolled out at New York State Electric & Gas (NYSEG). The Work Management system will standardize and modernize our engineering and field organizations. The system will improve our response to trouble calls and outages, and help us to reduce repetitive outages and customer complaints.

The new Customer Care system will replace an antiquated and difficult to maintain customer information system. It will facilitate customer interaction by creating a single point of contact for all inquiries related to billing, meter management and rate structures. We expect both of these initiatives to further improve customer satisfaction and generate additional cost savings in 2005 and beyond.

Consistent with our regulated electric and natural gas utility focus, we completed our exit from noncore businesses in 2004. Most significantly, we sold the Ginna nuclear plant and, in doing so, realized a number of benefits for customers and shareholders. First, the removal of the plant from our asset base reduced Energy East's risk and led to improved credit ratings. Second, proceeds from the sale were used to reduce debt by over $300 million, improving our financial flexibility and helping us to achieve our target equity ratio of 40% of total capitalization. Third, RG&E customers received refund checks totaling $60 million in 2004, with additional refunds scheduled over the next several years.

With another successful year behind us, we are very focused on the future. Over the next several years, we face some formidable challenges, but we believe we can effectively meet them.

Unlike other parts of the country, the Northeast does not have robust economic growth. Sales growth at our utilities has averaged about 1% to 2% per year; slightly higher in some areas such as Southern Maine, and slightly lower in others such as portions of upstate New York. This modest growth creates earnings growth challenges for us as the margins we gain are offset by cost increases associated with items such as health care, pensions, insurance and maintaining the safety and reliability of our utility infrastructure. This makes the next series of rate negotiations for our Connecticut natural gas utilities in 2005, NYSEG in 2006 and Central Maine Power (CMP) in 2007 important ones for Energy East.

The current PBR plans for those utilities have been enormously successful. Customers at CMP and NYSEG have seen their electric delivery rates decline 28% and 13%, respectively, while our natural gas distribution rates in Connecticut have been frozen since the mid-1990s. Factoring in inflation, our customers have realized significant price reductions. These customer benefits have been made possible, in part, by the $100 million of merger-enabled cost savings that we have realized. At the same time, shareholders have benefited from stable earnings and dividend growth.

Customers in upstate New York have also benefited from our "Voice Your Choice" program, which allows them to choose their energy supplier. One option available to customers that has proven to be very popular is a utility provided, fully bundled, fixed price service which includes both the cost of purchasing and distributing electricity to their home. Since NYSEG and RG&E sold the majority of their generating plants, as required by New York State regulators, they now purchase fixed price electricity for customers in a volatile wholesale supply market. NYSEG and RG&E manage this market price risk since most customers do not want to bear this risk themselves. This was never more apparent than in the fourth quarter of 2004 when over 300,000 customers, or 75% of those who enrolled in NYSEG's and RG&E's "Voice Your Choice" program, chose a bundled fixed price.

"In a J.D. Power and Associates study released this month, Energy East was recognized as one of the top utilities in the eastern United States for customer satisfaction."

Renewal of our PBR plans, including the "Voice Your Choice" program, is important. Our utilities must have the opportunity to recover the inflationary cost increases that they have absorbed, and the over $1 billion in capital investments they have made to ensure a safe, reliable and secure utility infrastructure, even if it means a delivery rate increase. State regulators must avoid the temptation to minimize the price impact of spiraling unregulated electric and natural gas commodity costs by squeezing distribution rates. This would not be good public policy.

By achieving new long-term PBR plans that reflect the investments we have made, and by continuing our vigilant cost controls and exploring opportunities to improve revenue growth through increased market penetration and expanded uses of electricity and natural gas, we believe we can continue to provide customers with stable prices and outstanding service, and shareholders with stable earnings and dividend growth.

In a recent survey of utility industry CEOs, new infrastructure investment, mergers and acquisitions, and cost cutting were cited as the top three likely drivers of growth for our industry over the next several years. At the same time, industry CEOs said that regulatory certainty is the most critical factor in achieving growth. We have proven that mergers and cost reductions can work. However, for this strategy to be successful, state regulators must appreciate the benefits that accrue to customers from merger-enabled savings and permit the sharing of benefits between customers and shareholders through incentive regulation policies or PBR plans.

Over the years, Energy East has benefited from the guidance of an experienced and insightful Board of Directors. This year three board members will retire: Dick Aurelio, Jim Carrigg and John Keeler. I would like to thank each of them for their leadership, integrity and dedication to our company, and wish them all a long and healthy retirement.

We recently added two new members to the board, John Cardis and Seth Kaplan. Both come with excellent experience. Mr. Cardis had a distinguished career at the accounting firm Deloitte & Touche, where he was a partner and a member of both the Executive Committee and the Board of Directors. Mr. Kaplan was a partner at the law firm Wachtell, Lipton, Rosen & Katz, where he specialized in corporate law for over 20 years, and is now a member of the faculty at Rutgers University School of Law. We are fortunate to have added two board members with such outstanding credentials.

On behalf of the Board of Directors, we thank you for your continued support.

Wes Von Schack

Wesley W. von Schack
Chairman, President & Chief Executive Officer

Financial Review

Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

Energy East Corporation's (Energy East or the company) primary operations, its electric and natural gas utility operations, are subject to rate regulation. The approved regulatory treatment on various matters could significantly affect the company's financial position and results of operations. Energy East has long-term rate plans for New York State Electric & Gas Corporation (NYSEG), Rochester Gas and Electric Corporation (RG&E), Central Maine Power Company (CMP), Connecticut Natural Gas Corporation (CNG), The Southern Connecticut Gas Company (SCG) and The Berkshire Gas Company (Berkshire Gas). The plans, which are discussed below, provide for sharing of achieved savings among customers and shareholders, allow for recovery of certain costs including exogenous and stranded costs, and provide stable rates for customers and revenue predictability for those six operating companies. As of January 31, 2005, Energy East had 6,092 employees.

Energy East's management focuses its strategic efforts on those areas of the company that it believes would have the greatest effect on shareholder value. Efficient operations are a key aspect of increasing shareholder value. Management has implemented plans to achieve savings through a company-wide restructuring that was completed in early 2004 and continued consolidation of utility support services.

The continuing uncertainty in the evolution of the utility industry, particularly the electric utility industry, has resulted in several federal and state regulatory proceedings that could significantly affect operations, although the outcomes of the proceedings are difficult to predict. Those proceedings could affect the nature of the electric and natural gas utility industries in New York and New England and are described below.

The company engages in various investing and financing activities to meet its strategic objectives. The primary goal of investing activities is to maintain a reliable energy delivery infrastructure. Investing activities are funded primarily with internally generated funds. Financing activities are focused on maintaining adequate liquidity, improving credit quality and minimizing the cost of capital.

Strategy

Energy East has maintained a consistent "pipes and wires" strategy over the past several years, focusing on the transmission and distribution of electricity and natural gas rather than the more volatile generation and energy trading businesses. Achieving operating excellence and efficiencies throughout the company is central to this strategy. While Energy East has sold certain noncore businesses and the last of its substantial regulated generation assets, investment in infrastructure that supports the electric and natural gas delivery systems continued in 2004. Also, the creation of a "utility shared services" organization has improved efficiencies and achieved savings from the integration of the company's information systems, purchasing, accounting and finance functions.

The company's long-term regulatory agreements continue to be a critical component to its success. While specific provisions may vary among the company's public utility subsidiaries, the overall strategy includes creating a stable rate environment that allows the companies to earn a fair return while minimizing price increases and sharing benefits with customers.

Electric Delivery Business

The company's electric delivery business consists primarily of its regulated electricity transmission, distribution and generation operations in upstate New York and Maine.

RG&E 2004 Electric and Natural Gas Rate Agreements | In May 2003 RG&E filed a rate case with the New York State Public Service Commission (NYPSC) to recover costs that RG&E had incurred and will continue to incur in providing safe and reliable electric and natural gas service. On May 20, 2004, the NYPSC approved the Electric and Natural Gas Joint Proposals that had been negotiated with Staff of the NYPSC and other interested parties and that address RG&E's electric and natural gas rates through 2008.

Key features of the Electric Rate Agreement include:

- Freezing electric delivery rates through December 2008, except for the implementation of a retail access surcharge effective May 1, 2004, that will recover $7 million annually.
- Allowing RG&E to recover its actual electricity supply costs during the period May 1, 2004, through December 31, 2004, through an Electric Supply Reconciliation mechanism.
- Refunding to customers over the term of the plan $110 million of the approximately $380 million net proceeds from the sale of the Ginna nuclear generating station (Ginna), including refunding $60 million after the closing, and refunding the remaining $50 million over the following three years. (See Sale of Ginna and Note 2 to the Consolidated Financial Statements.)
- Establishing an Asset Sale Gain Account (ASGA) with the net proceeds from the sale of Ginna. Portions of the ASGA will be used as follows:
  - To compensate RG&E for incremental supply costs resulting from the sale of Ginna;
  - To cover $6 million of replacement purchased power costs incurred in connection with a 2003 Ginna refueling outage;
  - To provide RG&E with revenue equivalent to a $2 million annual increase in electric delivery rates; and
  - To compensate RG&E for maximizing the sale value of Ginna through a credit to RG&E of $3.3 million annually over the term of the agreement.
- Establishing an earnings-sharing mechanism to allow customers and stockholders to share equally in earnings above a 12.25% return on equity (ROE) target. RG&E will be allowed to increase its earnings-sharing threshold to 12.50% by meeting yet-to-be-determined standards that will measure improvements in RG&E's retail access program. No sharing occurred in 2004 under this mechanism.
- Ensuring that RG&E continues to maintain the high quality of service and reliability it currently provides by specifying service quality and reliability standards and capital investment objectives.

RG&E estimates that $145 million will remain in the ASGA at the end of 2008. At that time the ASGA may be used at the discretion of the NYPSC for rate moderation, among other things.

Key features of the Natural Gas Rate Agreement include:

- Freezing natural gas delivery rates through December 2008, except for the implementation of a merchant function charge that will recover approximately $7 million annually beginning May 1, 2004.
- Implementing a weather normalization adjustment to protect both customers and RG&E from fluctuating revenues due to swings in temperature outside a normal range.
- Implementing gas cost incentive mechanisms to provide a means of sharing with customers any future gas supply cost savings that RG&E achieves.

- Establishing provisions similar to those in the Electric Rate Agreement regarding earnings sharing and service quality and reliability. The level for earnings sharing is 12.00%, with the opportunity to increase it to 12.25% if certain targets are achieved. No sharing occurred in 2004 under this mechanism.

The RG&E 2004 Electric and Natural Gas Rate Agreements resolve all outstanding issues related to RG&E's requests filed with the NYPSC in 2003. Those issues include:

- The deferral and recovery of costs, including interest, for restoration work resulting from a severe ice storm in April 2003.
- Recovery of replacement purchased power costs incurred in 2003 in connection with a scheduled refueling outage for Ginna.
- The deferral and true-up of estimated pension costs for the 16-month period through May 1, 2004, in accordance with the NYPSC's Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Post Retirement Benefits Other than Pensions.

In addition, RG&E has withdrawn its appeal of an order the NYPSC issued in March 2003 related to RG&E's February 2002 request filed with the NYPSC for new electric and natural gas rates that were to go into effect in January 2003.

Sale of Ginna | On June 10, 2004, after receiving all regulatory approvals, RG&E sold Ginna to Constellation Generation Group, LLC (CGG) and received $429 million in cash at closing. RG&E's Electric Rate Agreement resolves all regulatory and ratemaking aspects related to the sale of Ginna and provides for an ASGA, established at closing at approximately $357 million, and addresses the disposition of the asset sale gain. On September 9, 2004, RG&E received an additional $25 million from CGG related to certain post-closing adjustments, resulting in a $20 million increase to the ASGA. (See Note 2 to the Consolidated Financial Statements.)

Upon closing of the sale of Ginna, RG&E transferred $201 million of decommissioning funds to CGG. That amount fully meets the Nuclear Regulatory Commission's decommissioning funding requirements for Ginna. RG&E retained $77 million in excess decommissioning funds, which was credited to the ASGA. CGG is now responsible for all future decommissioning funding. The sale agreement included a 10-year, fixed-price power purchase agreement that calls for CGG to provide 90% of Ginna's output to RG&E.

RG&E Electric Rate Unbundling | In June 2003, as required by an NYPSC Order issued in March 2003 RG&E filed documentation with the NYPSC to unbundle commodity charges from delivery charges and to create electric commodity options for all customers. The Electric Rate Agreement provides for that unbundling and for the commodity options. Beginning January 1, 2005, customers have an opportunity to choose to purchase commodity service from RG&E at a fixed rate or at a price that varies monthly based on the market price of electricity. Alternatively, customers may continue to choose to purchase their commodity service from an energy service company (ESCO). Customers enrolled in these new commodity options between October 1, 2004, and December 31, 2004. Customers who did not make a choice will be served under RG&E's variable price option. Approximately 77% of those customers who made a choice selected RG&E's fixed price option. About 25% of RG&E's load is now served under this option.

RG&E Transmission Project | In September 2003 RG&E applied to the NYPSC for approval to upgrade its electric transmission system. The project includes building or rebuilding 38 miles of transmission lines and upgrading substations in the Rochester, NY area in order to assure adequate service to customers after the planned closing of RG&E's 257 megawatt coal-fired Russell Station in 2007. The estimated cost of the multi-year project is $75 million. Construction on the project is expected to begin in the spring of 2005.

On September 28, 2004, RG&E executed a Joint Proposal with Staff of the NYPSC, the New York State Department of Environmental Conservation and the New York State Department of Agriculture & Markets, requesting that the NYPSC issue a Certificate of Environmental Compatibility and Public Need for the project subject to certain terms and conditions. RG&E received the certificate from the NYPSC on December 15, 2004.

CMP Alternative Rate Plan | In September 2000 the Maine Public Utilities Commission (MPUC) approved CMP's Alternative Rate Plan (ARP 2000). ARP 2000 applies only to CMP's state jurisdictional distribution revenue requirement and excludes revenue requirements related to stranded costs and transmission services. ARP 2000 began January 1, 2001, and continues through December 31, 2007, with price changes, if any, occurring on July 1, in the years 2002 through 2007. Effective July 1, 2004, CMP's distribution prices decreased by about 2% as a result of inflation being less than the productivity offset for 2004. In addition, CMP decreased its transmission rates to eliminate billings for congestion costs that have been fully recovered and, pursuant to its formula rate approved by the Federal Energy Regulatory Commission (FERC), to reflect CMP's and the New England Power Pool's (NEPOOL) actual costs for 2003.

CMP Electricity Supply Responsibility | Under a Maine State Law adopted in 1997, CMP was mandated to sell its generation assets and relinquish its supply responsibility. CMP no longer owns any generating assets but retains its power entitlements under long-term contracts with nonutility generators (NUGs) and a power purchase contract with the Vermont Yankee nuclear generating station (Vermont Yankee). In December 2004 the MPUC approved CMP's sale of those entitlements for various periods ranging from one to three years, through February 29, 2008, depending on the type of entitlement. CMP's retail electricity prices are set to provide recovery of the costs in excess of the entitlement sale associated with its ongoing power entitlement obligations.

Under Maine State Law the MPUC can mandate that CMP be a standard-offer provider of electricity supply service for retail customers if the MPUC should deem bids by competitive suppliers to be unacceptable. In January 2005 the MPUC chose suppliers of standard-offer electricity for the six months ending August 31, 2005, for the medium and large customer classes. In December 2004 the MPUC chose Constellation Energy Commodities Group, LLC (CEC Group) as the new supplier of standard-offer electricity to CMP's residential and small commercial customers (100% for the first year, 66.6% for the second year and 33.3% for the third year) for a three-year period beginning March 1, 2005. CMP has no standard-offer obligations through August 2005 and has not had any standard-offer obligations since March 2002. If in the future CMP should have standard-offer obligations, there would be no effect on its net income because CMP is ensured cost recovery through Maine State Law for any standard-offer obligations. CMP's revenues and purchased power costs would fluctuate, however, if it were required to be a standard-offer provider. (See Operating Results for the Electric Delivery Business and Note 10 to the Consolidated Financial Statements.)

CMP Stranded Cost Proceeding | Through its stranded cost rates, CMP recovers the above-market costs of its purchased power agreements, as well as costs incurred to decommission and dismantle the nuclear facilities in which CMP has an ownership share, pursuant to Maine statute. In January 2005 the MPUC approved new stranded cost rates for the three-year period ending February 2008.

CMP Nuclear Costs | CMP has ownership interests in three nuclear facilities in New England that have been permanently shut down, and are in the process of being decommissioned: Maine Yankee Atomic Power Company (38% ownership), Connecticut Yankee Atomic Power Company (6% ownership) and Yankee Atomic Electric Power Company (9.5% ownership) (the Yankee companies). The Yankee companies commenced litigation in 1998 charging that the federal government had breached the contracts it entered into with each of the Yankee companies in 1983. The contracts provided for the federal government to begin removing spent nuclear fuel from the Maine Yankee, Connecticut Yankee and Yankee Rowe nuclear plants, which are owned by the Yankee companies, no later than January 31, 1998, in return for payments by each of the Yankee companies. Two federal courts found that the federal government did breach its contracts with the Yankee companies and other utilities. A trial to determine the monetary damages owed to the Yankee companies for the United States Department of Energy's (DOE) continued failure to remove spent nuclear fuel began in the U.S. Court of Federal Claims in July 2004 and final trial arguments were made in January 2005. The Yankee companies' individual damage claims are specific to each plant and include costs through 2010, the earliest year the DOE expects that it will begin removing fuel. The Yankee companies' damage claims total approximately $543 million and CMP's sponsor-weighted share is approximately $90 million. The claims also note additional costs that will be incurred for each year that fuel remains at the sites beyond 2010. If the Yankee companies prevail in these cases, any damages awarded by the Court of Federal Claims would be credited to their respective decommissioning or spent fuel trust funds. Any remaining funds would be returned to electric customers when decommissioning is complete. The Yankee companies expect a trial court decision in the second half of 2005. CMP cannot predict the outcome of this litigation.

The FERC approved a settlement agreement in 2000 (2000 Settlement) regarding recovery of decommissioning costs and plant investment and all issues with respect to the prudence of the decision to discontinue operation of the Connecticut Yankee plant. Pursuant to the 2000 Settlement, on July 1, 2004, Connecticut Yankee filed a revised schedule of decommissioning charges to be collected from its wholesale customers, based on an updated estimate of the costs of decommissioning. Estimated decommissioning and long-term spent fuel storage costs for the period 2000 through 2023 increased by approximately $390 million in 2003 dollars compared to the April 2000 estimate of $434 million approved in the 2000 Settlement. The revised estimate reflects the fact that Connecticut Yankee is now self-performing all work to complete the decommissioning of the plant due to the termination of Bechtel Power Corporation (Bechtel), the turnkey decommissioning contractor, in July 2003. In addition, the revised estimate reflects increases in the projected costs for spent fuel storage, security, and liability and property insurance. The estimated remaining costs for decommissioning and long-term spent fuel storage as of December 31, 2003, totaled approximately $504 million in 2003 dollars.

Connecticut Yankee is seeking recovery of incremental decommissioning costs and other damages from Bechtel and, if necessary, its surety. In response, Bechtel has filed a complaint in Connecticut Superior Court seeking damages of $93 million for wrongful termination of the decommissioning contract. Connecticut Yankee has filed counterclaims for excess completion costs and other damages. Discovery is under way and a trial is scheduled for May 2006. CMP cannot predict the outcome of this litigation.

The revised schedule for decommissioning collections is based on the 2003 estimate. Based on the revised schedule, increased collections of $93 million annually commenced in January 2005 and extend through December 2010. Any increase in rates approved by the FERC will be charged to Connecticut Yankee's owners, including CMP, whose share of a $93 million increase would be approximately $6 million. Under regulatory settlements, CMP is allowed to defer for future recovery any increases in decommissioning costs. Pursuant to a recent stranded cost settlement, CMP will begin to collect the higher Connecticut Yankee decommissioning costs through rates in March 2005.

On June 10, 2004, the Connecticut Department of Public Utility Control (DPUC) and the Connecticut Office of Consumer Counsel filed a petition with the FERC asking it to determine that, if the FERC should find any of Connecticut Yankee's decommissioning costs were not prudently incurred, the owners may not recover those costs in rates that are ultimately charged to retail customers. Instead, the DPUC believes that the owners of Connecticut Yankee must bear the costs. Connecticut Yankee and its owners, including CMP, filed protests to contest this petition. On August 30, 2004, the FERC rejected the DPUC's petition; approved Connecticut Yankee's rate increase effective February 1, 2005, subject to refund; and set for hearing the remaining issues. The DPUC has requested rehearing of the FERC's August 30, 2004 Order. CMP cannot predict the outcome of these proceedings.

NYSEG Electric Rate Plan | In February 2002 the NYPSC issued an order (NYPSC February 2002 Order) approving a five-year NYSEG electric rate plan, which extends through December 31, 2006, and Energy East's merger with RGS Energy Group, Inc. (RGS Energy). NYSEG's and the company's earnings were lower in 2002 as a result of the electric rate plan because NYSEG's electric rates were adjusted to reflect the sale of generation assets completed in 1999.

The NYPSC February 2002 Order reduced annualized electric rates by $205 million for NYSEG customers effective March 1, 2002, which amounted to an overall average reduction of 13% for most customers. In the first rate year ending December 31, 2002, approximately $55 million of the annualized reduction was funded with the partial amortization of an ASGA created as a result of NYSEG's sale in 2001 of its interest in Nine Mile Point 2 nuclear generating station (NMP2). The NYPSC February 2002 Order also requires equal sharing of earnings between NYSEG customers and shareholders of ROEs in excess of 15.5% for 2002, and equal sharing of the greater of ROEs in excess of 12.5% on electric delivery, or 15.5% on the total electric business (including supply) for each of the years 2003 through 2006. For purposes of earnings sharing, NYSEG is required to use the lower of its actual equity or a 45% equity ratio, which approximates $720 million. Earnings levels were sufficient to generate estimated sharing with customers of $17 million in 2004 and $7 million in 2003.

Nonutility Generation | CMP and NYSEG together expensed approximately $613 million for NUG power in 2004. They estimate that their combined NUG power purchases will total $674 million in 2005, $615 million in 2006, $563 million in 2007, $381 million in 2008 and $229 million in 2009. CMP and NYSEG continue to seek ways to provide relief to their customers from above-market NUG contracts that state regulators ordered the companies to sign, and which, in 2004, averaged 9.5 cents per kilowatt-hour for CMP and 10.2 cents per kilowatt-hour for NYSEG. Recovery of these NUG costs is provided for in CMP's stranded cost rates and NYSEG's current electric rate plan. (See Note 10 to the Consolidated Financial Statements.)

NYPSC Collaborative on End State of Energy Competition | In March 2000 the NYPSC instituted a proceeding to address the future of competitive electric and natural gas markets, including the role of regulated utilities in those markets. Other objectives of the proceeding include identifying and suggesting actions to eliminate obstacles to the development of those competitive markets and providing recommendations concerning provider of last resort and related issues. In January 2004 the NYPSC issued a notice seeking additional comments in light of the passage of time and the evolution of competitive markets. In March and April 2004 NYSEG and RG&E submitted comments supporting periodic assessment of the retail competitive marketplace and opposing the adoption of any policies restricting customer choice of supplier or limiting the availability of supply options from any particular supplier. NYSEG and RG&E believe that the NYPSC should not adopt a single end-state vision for New York and should maintain flexibility by addressing each utility in the context of that utility's unique circumstances.

On August 25, 2004, the NYPSC issued a Statement of Policy on Further Steps Toward Competition in Retail Energy Markets recommending that all potentially competitive utility functions be opened to competition. While it is not possible to determine when markets will become workably competitive, all utilities will be required to prepare plans to foster the development of retail energy markets. The plans can vary by individual utility, and NYSEG and RG&E do not expect that statement of policy to affect their commodity service options under their current rate plans.

In a separate phase of this proceeding, on August 25, 2004, the NYPSC issued a Statement of Policy on Unbundling and Order Directing Tariff Filings. Utilities are directed to file embedded cost studies and competitive rates in future rate plans or requests for extensions and to begin tracking the costs of and revenues generated by competitive energy services. The order also allows parties to file comments and replies on rate design issues discussed in the order.

NYSEG and RG&E are not able to predict what effect, if any, these latest developments will have on future operations.

New England RTO | In January 2003, in order to promote Regional Transmission Organizations (RTOs), the FERC issued a proposed policy statement on transmission pricing. The FERC proposed a 50 basis point ROE incentive adder on facilities for which transmission owners turn control over to an RTO and a 100 basis point ROE incentive adder for new transmission facilities found appropriate through an RTO planning process. In October 2003 ISO New England, Inc. (ISO New England) and the New England transmission owners, including CMP, made a joint filing with the FERC to establish ISO New England as a qualified RTO. As an RTO, ISO New England will be responsible for the independent operation of the regional transmission system and regional wholesale energy market. The transmission owners will retain ownership of their transmission facilities and control over their revenue requirements. In a related filing, in November 2003 the New England transmission owners, including CMP, requested a joint baseline ROE and the above incentives as part of the proposal for a New England RTO.

In March 2004 the FERC issued an order that accepted a six-state New England RTO as proposed by ISO New England and the New England transmission owners. The order approved the 50 basis point and the 100 basis point ROE incentive adders, but limited application of the 100 basis point adder to regional facilities, subject to suspension, hearing and application of the FERC's Pricing Policy Statement, when it is issued. The order also accepted, subject to suspension and hearing, the New England transmission owners' proposed base level ROE of 12.8% applicable to rates for local and regional transmission service, to be effective, subject to refund, on the New England RTO operational commencement date, February 1, 2005. Evidentiary hearings on the final base level ROE and the incentive for new transmission investment began on January 25, 2005. A final decision from the FERC on those issues is not expected until the end of 2005. The New England transmission owners and ISO New England implemented the New England RTO effective February 1, 2005.

FERC Standard Market Design | In October 2001 FERC commenced a proceeding to consider national standard market design (SMD) issues, and in July 2002 issued a Notice of Proposed Rulemaking (NOPR) concerning those issues. The SMD NOPR proposes rules that would require, among other things, changes in the wholesale power markets, transmission planning, services and charges, market power monitoring and mitigation, and the organization and structure of ISOs. CMP, NYSEG and RG&E filed comments jointly with other transmission owners in November 2002 and in early 2003. In April 2003 the FERC issued a white paper on SMD in which the FERC accommodates greater regional flexibility and seeks further comments. The SMD white paper includes a preference for energy markets based on locational marginal pricing (LMP), which represents a significant change for some regions of the country. The New York Independent System Operator (NYISO) and ISO New England already operate markets based on LMP. The companies are not able to predict the SMD's ultimate effect, if any, on their results of operations or financial position. The LMP market design was incorporated into the New England RTO filing approved by the FERC, which is discussed above.

Transmission Planning and Expansion and Generation Interconnection | In July 2003 ISO New England and the NEPOOL submitted a filing to the FERC concerning transmission expansion cost allocation, which the FERC approved in December 2003. CMP, among other parties, requested rehearing of that FERC decision, arguing that it would require customers who would not benefit from new transmission projects to contribute to those project costs. On December 2, 2004, the FERC denied rehearing of its order. ISO New England and other parties filed a motion for clarification. The FERC issued an order on January 5, 2005, granting clarification and deciding that all of the pending transmission projects would be subject to the ISO New England cost allocation process.

The FERC approved the NYISO's comprehensive planning process for reliability needs on December 28, 2004, requiring several relatively minor changes to the NYISO proposal. NYSEG and RG&E support the NYISO plan. The NYISO made a related compliance filing on February 28, 2005. On February 25, 2005, the FERC issued an order giving itself more time to issue a decision on requests for rehearing related to this issue. Discussions continue among the NYISO market participants on an economic planning process.

In July 2003 the FERC issued Order 2003 regarding generation interconnection terms, conditions and cost allocation that would require modifications to the companies' interconnection processes. The FERC issued Order 2003-A in March 2004 and Order 2003-B in December 2004, reaffirming its determinations in Order 2003, clarifying certain provisions, and directing compliance. On February 18, 2005, the NYISO and the New York transmission owners (NYTOs) submitted a joint compliance filing, pursuant to Order 2003-B, to modify certain sections of the Large Facility Interconnection Procedures and Large Facility Interconnection Agreement contained in the NYISO Open Access Transmission Tariff. Comments on the filing were due on March 11, 2005.

In January and April 2004 the NEPOOL and the New England transmission owners made separate compliance filings in response to Orders 2003 and 2003-A. In November 2004 the FERC issued an order that accepted the NEPOOL filing in part and rejected the New England transmission owners' filing. On January 28, 2005, ISO New England and the New England transmission owners made a joint compliance filing, to supersede and replace their earlier separate filings, proposing a standardized agreement and single set of procedures for generators rated 5 megawatts or greater seeking interconnection service under the RTO tariff on or after February 1, 2005.

Manufactured Gas Plant Remediation Recovery | RG&E and NYSEG independently began cost contribution actions against FirstEnergy Corp. (formerly GPU, Inc.) in federal district court; RG&E in the Western District of New York in August 2000 and NYSEG in the Northern District of New York in April 2003. The actions are for both past and future costs incurred for the investigation and remediation of inactive manufactured gas plant sites. The RG&E action is also being mediated and the parties are in the final stages of discovery. RG&E and NYSEG are unable to predict the outcome of these actions at this time.

NYISO Billing Adjustment | The NYISO frequently bills transmission owners on a retroactive basis when adjustments are necessary. Such retroactive billings can cover several months or years and cannot be reasonably estimated. NYSEG and RG&E record transmission revenue or expense as appropriate when revised amounts can be estimated. On January 25, 2005, the NYISO notified NYTOs, including NYSEG and RG&E, of a revenue allocation formula error related to transmission congestion contracts for periods including May 2000 through October 2002. The NYISO has not yet provided any further details. The correction of the error may result in revised billings for NYSEG and RG&E. The companies cannot predict at this time either the magnitude or the direction of any billing adjustments.

Locational Installed Capacity Markets | In 2003 the FERC required ISO New England to file a proposed mechanism to implement by January 1, 2006, location or deliverability requirements in the installed capacity or resource adequacy market to ensure that generators that provide capacity within areas of New England are appropriately compensated for reliability. In response, in 2004 ISO New England developed and filed with the FERC a locational installed capacity (LICAP) market proposal based on an administratively set demand curve. The FERC has refused to consider alternatives to ISO New England's proposal and has set issues regarding the exact LICAP parameters and its implementation for hearing before a FERC administrative law judge. CMP and other parties representing customers who would ultimately pay the cost of the LICAP charges as a component of energy supply costs have opposed the FERC orders requiring an administratively set capacity market and ISO New England's particular proposal. Generators that supply capacity in ISO New England's market have generally supported the FERC's order and the basic design of ISO New England's proposal. A recommended decision by the FERC administrative law judge is expected by June 1, 2005. CMP cannot predict how the FERC will rule on the filing or what modifications the FERC might make to the filing.

Errant Voltage | In January 2005 the NYPSC issued an Order Instituting Safety Standards in response to a pedestrian being electrocuted from contact with an energized service box cover in New York City, which is outside the company's service territory. All New York utilities were directed to respond by February 19, 2005, with a report that provides a detailed voltage testing program, an inspection program and schedule, safety criteria applied to each program, a quality assurance program, a training program for testing and inspections and a description of current or planned research and development activities related to errant voltage and safety issues. The Order Instituting Safety Standards also denies utility requests for recovery of implementation costs and establishes criteria for utilities seeking authorization to recover costs as an incremental expense. In addition, penalties for failure to achieve annual performance targets for testing and inspections were established at 75 basis points each. NYSEG and RG&E have reviewed the NYPSC order and jointly filed in early February 2005, with two other New York State utilities, a petition for rehearing focused on several areas including the impracticability of the timetable established in the order. In addition, NYSEG and RG&E filed a separate petition for rehearing dealing with the recovery of incremental costs of complying with the order. NYSEG and RG&E do not know what actions will be taken on the petitions for rehearing. In late February 2005 NYSEG and RG&E filed a testing and inspection plan in response to the order consistent with the timetable identified in the above noted joint petition for rehearing.

CMP Union Contract | Effective April 30, 2004, the union contract expired between CMP and the local union of the International Brotherhood of Electrical Workers. On May 5, 2004, the union membership voted to accept CMP's offer for a new contract, which expires on April 30, 2009. The contract provides for wage increases of 3.25% in 2004, 3.0% in each year 2005, 2006 and 2007, and 2.75% in 2008. It also includes provisions for active employees to contribute to medical insurance plans by the end of the contract period and for employees who retire on or after July 1, 2005, to contribute toward the cost of medical insurance according to a predetermined schedule.

NYSEG Union Contract | The contract between NYSEG and the local unions of the International Brotherhood of Electrical Workers was scheduled to expire effective July 1, 2005. On October 19, 2004, the union membership voted to accept NYSEG's offer to extend the contract until June 30, 2010. The contract provides for annual 3% wage increases for 2005 through 2009. It includes provisions for active employees to contribute to medical insurance plans by the end of the contract period.

RG&E Union Contract | In April 2003 RG&E's electric and natural gas field operations personnel voted to be represented by the International Brotherhood of Electrical Workers. RG&E recognizes the employees' right to make this decision and respects the collective votes of its employees. A negotiated labor agreement is in effect for the period September 2003 through May 2008. The agreement provides for annual 3% wage increases.

Natural Gas Delivery Business

The company's natural gas delivery business consists of its regulated natural gas transportation, storage and distribution operations in New York, Connecticut, Maine and Massachusetts.

RG&E 2004 Electric and Natural Gas Rate Agreements | See Electric Delivery Business.

Natural Gas Supply Agreements | Energy East's natural gas companies – NYSEG, RG&E, SCG, CNG, Berkshire Gas and Maine Natural Gas Corporation – have a three-year strategic alliance with BP Energy Company, effective April 1, 2004, that provides the companies the right to acquire natural gas supply and optimizes transportation and storage services.

NYSEG Natural Gas Rate Plan | NYSEG's Natural Gas Rate Plan, which became effective October 1, 2002, freezes overall delivery rates through December 31, 2008, implements a natural gas supply charge to collect the actual costs of natural gas and contains an earnings-sharing mechanism. The earnings-sharing mechanism requires equal sharing of earnings between NYSEG customers and shareholders of ROEs in excess of 11.5% for the 27-month period ended December 31, 2004, and in excess of 12.5% for each of the calendar years from 2005 through 2008. For purposes of earnings sharing, NYSEG is required to use the lower of its actual equity or a 45% equity ratio, which approximates $250 million. No sharing occurred in 2004 or 2003.

On June 30, 2004, NYSEG filed a Joint Proposal, executed by NYSEG and other parties, to resolve outstanding issues in NYSEG's Natural Gas Rate Plan related to its natural gas delivery rate design, natural gas economic development plan and its natural gas Affordable Energy Program. Pursuant to NYSEG's Natural Gas Rate Plan, delivery rate designs in the Joint Proposal were developed for each of the remaining years on an overall revenue neutral manner, consistent with the billing units and firm delivery revenues contained in NYSEG's Natural Gas Rate Plan. The NYPSC approved all provisions of the Joint Proposal effective September 23, 2004. The first year of a five-year phase-in of delivery rates for nonresidential customers went into effect October 1, 2004. The first of four annual changes to residential rates will become effective October 1, 2005.

NYPSC Collaborative on End State of Energy Competition | See Electric Delivery Business.

SCG Request for Recovery of Exogenous Costs | In December 2003 SCG filed an application with the DPUC to recover approximately $21 million of exogenous costs under its approved Incentive Rate Plan (IRP). The exogenous costs to be recovered include qualified pension and other postretirement benefits expenses, taxes, uncollectible expense and the cost of SCG's Customer Hardship Arrearage Forgiveness Program. Those costs were the result of events that were unanticipated and beyond SCG's control. SCG's IRP decision from the DPUC allows SCG to petition for relief from substantial and material costs resulting from such exogenous events. The DPUC established a docket for this proceeding and hearings were held in April 2004. On October 27, 2004, the DPUC issued a final decision that denied current recovery of exogenous costs but recognized that the costs would be reviewed in SCG's next rate case. On December 9, 2004, SCG filed an appeal with the Connecticut Superior Court concerning certain aspects of the DPUC's decision.

Connecticut Regulatory Proceedings | SCG's IRP expires September 30, 2005. As a result of the DPUC's decision denying recovery of exogenous costs, SCG anticipates filing for rate relief in the second quarter of 2005. The rate filing will request, among other items, a greater level of recovery of deferred costs, similar to SCG's request for recovery of exogenous costs. CNG's IRP expires September 30, 2005, and CNG has notified the DPUC that it intends to continue to operate under an IRP for another multi-year period.

Connecticut Merger-Enabled Gas Supply Savings and Gas Cost Reduction Plan Filings | In 2001 CNG and SCG submitted filings to the DPUC regarding merger-enabled gas supply savings (MEGS) and a gas-cost reduction plan, which covered the initial period April 1, 2001, through September 30, 2001. CNG provided calculations for total MEGS of $1.3 million and SCG provided calculations for total MEGS of $2.2 million. In February 2003, based on its understanding of the components of the MEGS, the DPUC issued a draft decision on CNG's and SCG's filed MEGS and gas-cost reduction plan results, modifying the MEGS amounts to $134,000 for CNG and $9,000 for SCG. CNG and SCG filed comments and additional detail with regard to the draft decision. On March 26, 2004, the DPUC issued a notice that encouraged the parties to settle the MEGS issue, which resulted in the assignment of Prosecutorial Staff of the DPUC to assist in the settlement process. The docket was suspended to allow the settlement process to proceed. On September 22, 2004, Prosecutorial Staff reported that the parties had reached an agreement in principle to settle these proceedings. On December 17, 2004, a settlement between SCG, CNG, the Office of Consumer Counsel and the Prosecutorial Division of the Department was filed with the DPUC. The settlement fully resolves the companies' claims to MEGS. Hearings took place in February 2005 and the final decision on this settlement was approved on February 23, 2005.

NYSEG Union Contract | See Electric Delivery Business.

RG&E Union Contract | See Electric Delivery Business.

Berkshire Gas Union Contract | Effective April 1, 2003, the union contract expired between Berkshire Gas and the local union of the United Steelworkers of America. In 2004 the union members voted to accept Berkshire Gas' offer of a new contract that will expire on March 31, 2009. The contract provides for wage increases of 3% for each year of the contract.

Other Businesses

The company's other businesses include a nonutility generating company, retail energy marketing companies, telecommunications assets, a district heating and cooling system, a FERC-regulated liquefied natural gas peaking plant and an energy services company.

Sale of Other Businesses | The company continues to rationalize its nonutility businesses to ensure that they fit its strategic focus. On July 26, 2004, Union Water Power Company (UWP), a subsidiary of CMP Group, Inc. (CMP Group), sold all of the assets related to its utility locating and construction divisions. The after-tax loss resulting from the sale was approximately $7 million and includes a reduction in the goodwill that was assigned to UWP at the time of Energy East's purchase of CMP Group. On October 1, 2004, Energy East Solutions, Inc., a subsidiary of The Energy Network, Inc., completed the sale of its New England and Pennsylvania natural gas customer contracts and related assets. (See Note 3 to the Consolidated Financial Statements.)

Other Matters

New Accounting Standard

Statement 123R | In December 2004 the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment (Statement 123R), which is a revision of Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation. Statement 123R requires a public entity to measure the cost of employee services that it receives in exchange for an award of equity instruments based on the grant-date fair value of the award and recognize that cost over the period during which the employee is required to provide service in exchange for the award. Statement 123R also requires a public entity to initially measure the cost of employee services received in exchange for an award of liability instruments based on the award's current fair value, subsequently remeasure the fair value of the award at each reporting date through the settlement date and recognize changes in fair value during the required service period as compensation cost over that period. The company's adoption of Statement 123R is not expected to have a material effect on its financial position or results of operations. (See Note 1 to the Consolidated Financial Statements.)

Contractual Obligations and Commercial Commitments

At December 31, 2004, the company's contractual obligations and commercial commitments are:

	Total	2005	2006	2007	2008	2009	After 2009
(Thousands)							
Contractual Obligations							
Long-term debt(1)	$6,500,997	$241,036	$523,014	$379,175	$264,235	$321,649	$4,771,888
Capital lease obligations(1)	52,609	5,374	4,936	4,596	4,472	4,347	28,884
Operating leases	95,304	15,327	11,678	10,775	8,747	8,713	40,064
Nonutility generator purchase power obligations	3,090,362	674,500	614,951	562,945	380,910	228,891	628,165
Nuclear plant obligations(2)	275,234	36,688	32,176	29,868	24,828	15,948	135,726
Unconditional purchase obligations	2,907,783	594,800	403,095	382,789	338,901	275,793	912,405
Pension and other postretirement benefits(3)	2,093,267	173,699	179,328	184,602	191,386	199,431	1,164,821
Other long-term obligations	18,426	5,579	3,838	3,143	1,854	1,618	2,394
Total Contractual Obligations	$15,033,982	$1,747,003	$1,773,016	$1,557,893	$1,215,333	$1,056,390	$7,684,347

(1) Amounts for long-term debt and capital lease obligations include future interest payments. Future interest payments on variable-rate debt are determined using the rates at December 31, 2004.

(2) See Sale of Ginna.

(3) Amounts are through 2014 only.

Energy East has two revolving credit agreements in which it covenants to maintain certain debt ratios. CMP has a revolving credit facility, secured by its accounts receivable, in which it covenants to maintain certain debt and earnings ratios. NYSEG and RG&E have a joint revolving credit agreement in which they each covenant to maintain certain debt and earnings ratios. RG&E has a credit agreement in which it covenants to maintain the same debt and earnings ratios as in its joint revolving credit agreement. (See Note 8 to the Consolidated Financial Statements.)

Critical Accounting Estimates

In preparing the financial statements in accordance with generally accepted accounting principles, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. The company's most critical accounting estimates include the effects of utility regulation on its financial statements, and the estimates and assumptions used to perform the annual impairment analyses for goodwill and other intangible assets, to calculate pension and other postretirement benefits and to estimate unbilled revenues.

Statement 71 | Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (Statement 71) allows companies that meet certain criteria to capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future periods. Those companies record, as regulatory liabilities, obligations to refund previously collected revenue or obligations to spend revenue collected from customers on future costs.

The company believes its public utility subsidiaries will continue to meet the criteria of Statement 71 for their regulated electricity and natural gas operations in New York State, Maine, Connecticut and Massachusetts; however, the company cannot predict what effect a competitive market or future actions of the NYPSC, MPUC, DPUC, Massachusetts Department of Telecommunications and Energy or FERC will have on their ability to continue to do so. If the company's public utility subsidiaries can no longer meet the criteria of Statement 71 for all or a separable part of their regulated operations, they may have to record as expense or revenue certain regulatory assets and liabilities.

Approximately 90% of the company's revenues are derived from operations that are accounted for pursuant to Statement 71. The rates the utilities charge their customers are based on cost basis regulation reviewed and approved by those regulatory commissions.

Goodwill and Other Intangible Assets | The company does not amortize goodwill or intangible assets with indefinite lives. The company tests both goodwill and intangible assets with indefinite lives for impairment at least annually. The company amortizes intangible assets with finite lives and reviews them for impairment. Impairment testing includes various assumptions, primarily the discount rate and forecasted cash flows. Impairment testing was conducted using a range of discount rates representing the company's marginal, weighted-average cost of capital and a range of assumptions for cash flows. Changes in those assumptions outside of the ranges analyzed could have a significant effect on the company's determination of an impairment. The company did not have any impairment in 2004 of its goodwill or intangible assets with indefinite lives. (See Note 5 to the Consolidated Financial Statements.)

Pension and Other Postretirement Benefit Plans | The company has pension and other postretirement benefit plans covering substantially all of its employees. In accordance with Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions and Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, the valuation of benefit obligations and the performance of plan assets are subject to various assumptions. The primary assumptions include the discount rate, expected return on plan assets, rate of compensation increase, health care cost inflation rates, expected years of future service under the pension benefit plans and the methodology used to amortize gains or losses. Changes in those assumptions could have a significant effect on the company's noncash pension income or expense or on the company's postretirement benefit costs. As of December 31, 2004, the company decreased the discount rate from 6.25% to 5.75%. (See Quantitative and Qualitative Disclosures About Market Risk – Other Market Risk, and Note 16 to the Consolidated Financial Statements.)

Unbilled Revenues | The company's unbilled revenues represent estimates of receivables for energy provided but not yet billed. The estimates are determined based on various assumptions, such as current month energy load requirements, billing rates by customer classification and loss factors. Changes in those assumptions could significantly affect the estimates of unbilled revenues.

Liquidity and Capital Resources

Cash Flows

The following table summarizes the company's consolidated cash flows for 2004, 2003 and 2002.

Year Ended December 31	2004	2003	2002
(Thousands)			
Operating Activities			
Net income	**$229,337**	$210,446	$188,603
Noncash adjustments to net income	**431,700**	482,345	282,262
Changes in working capital	**(227,726)**	(127,610)	52,892
Other	**(94,211)**	(89,414)	(72,399)
Net Cash Provided by Operating Activities	**339,100**	475,767	451,358
Investing Activities			
Sale of generation assets	**453,678**	–	59,442
Excess decommissioning funds retained	**76,593**	–	–
Acquisitions, net of cash acquired	**–**	–	(681,397)
Utility plant additions	**(299,263)**	(289,320)	(224,450)
Other	**1,600**	26,740	(15,549)
Net Cash Provided by (Used in) Investing Activities	**232,608**	(262,580)	(861,954)
Financing Activities			
Net issuance of common stock	**(2,988)**	4,234	435
Net (repayments of) increase in debt and preferred stock of subsidiaries	**(333,095)**	(239,745)	379,911
Dividends on common stock	**(136,374)**	(127,940)	(110,186)
Net Cash (Used in) Provided by Financing Activities	**(472,457)**	(363,451)	270,160
Net Increase (Decrease) in Cash and Cash Equivalents	**99,251**	(150,264)	(140,436)
Cash and Cash Equivalents, Beginning of Year	**147,869**	298,133	438,569
Cash and Cash Equivalents, End of Year	**$247,120**	$147,869	$298,133

Due to the merger completed on June 28, 2002, the company's consolidated cash flows include RGS Energy beginning with July 2002.

The total of cash flows from operating and investing activities in 2004 was $572 million as compared to $213 million in 2003. The increase of $359 million was primarily due to proceeds from the sale of Ginna and excess decommissioning funds retained that totaled $530 million. That increase was partially offset by a decrease in net cash provided by operating activities in 2004 related to the sale of Ginna. (See Note 2 to the Consolidated Financial Statements.)

Operating Activities Cash Flows | Net cash provided by operating activities was $339 million in 2004 compared to $476 million in 2003 and $451 million in 2002. The $137 million decrease in 2004 primarily resulted from:

- The $60 million of net proceeds from the sale of Ginna that was refunded to RG&E customers in 2004 as provided in RG&E's Electric Rate Agreement.
- Increased tax payments of $74 million primarily due to the elimination of deferred tax liabilities due to the sale of Ginna.
- Increased expenditures of $44 million to replenish natural gas inventories.

The $24 million increase in net cash provided by operating activities in 2003 was primarily due to:

- A full year of cash flows provided by operating activities in 2003 compared to six months in 2002, as a result of the company's acquisition of RGS Energy in June 2002.

The company's pension plans generated pretax noncash pension income (net of amounts capitalized) of $29 million in 2004, $40 million in 2003 and $70 million in 2002. The $11 million decrease in 2004 and the $30 million decrease in 2003 were primarily due to revised actuarial assumptions including the discount rate used to compute the company's pension liability (reduced from 7.0% to 6.50% as of December 31, 2002, and to 6.25% as of December 31, 2003). Pension income for 2005 is estimated at $26 million. The company estimates contributions of $54 million to its pension plans in 2005. (See Note 16 to the Consolidated Financial Statements.)

Investing Activities Cash Flows | Net cash provided by investing activities was $233 million in 2004 compared to net cash used in investing activities of $263 million in 2003 and $862 million in 2002. The $495 million increase in cash in 2004 primarily resulted from the sale of Ginna. The decrease in cash used of $599 million in 2003 was primarily due to the effect of $681 million of cash paid in 2002 to acquire RGS Energy, net of $59 million of cash received in 2002 related to NYSEG's sale of its interest in NMP2 in 2001.

Capital spending totaled $299 million in 2004, $303 million in 2003, and $229 million in 2002, including capital spending for RGS Energy beginning with July 2002 and nuclear fuel for RG&E from July 2002 until early June 2004. Capital spending in all three years was financed principally with internally generated funds and was primarily for the extension of energy delivery service, necessary improvements to existing facilities, compliance with environmental requirements and governmental mandates and merger integration beginning in 2003.

Capital spending is projected to be $388 million in 2005. It is expected to be paid for principally with internally generated funds and will be primarily for the same purposes described above, as well as a customer care system and an Infrastructure Replacement Program. (See Note 10 to the Consolidated Financial Statements.)

Financing Activities Cash Flows | Net cash used in financing activities was $472 million in 2004 compared to $363 million in 2003. The $109 million increase was primarily the result of higher net repayments of debt due in part to funds available from the sale of Ginna. For 2002, the $270 million of net cash provided by financing activities reflects the company's borrowing to fund the acquisition of RGS Energy.

The financing activities discussed below include those activities necessary for the company and its principal subsidiaries to maintain adequate liquidity, improve credit quality and ensure access to capital markets. Activities include minimal common stock issuances in connection with the company's Investor Services Program and employee stock-based compensation plans, and various medium-term and long-term debt transactions. They also include steps taken by RG&E to revise its capital structure as a result of the sale of Ginna. (See Notes 7, 8 and 9 to the Consolidated Financial Statements.)

The company's financing activities included:

- Raising its common stock dividend 6% in October 2004 to a new annual rate of $1.10 per share and raising its long-term dividend payout ratio target from 65% to 75% of earnings.
- During 2004 issuing 871,838 shares of company common stock, at an average price of $23.99 per share, through the company's Investor Services Program. The shares were original issue shares.
- In the first quarter of 2004, awarding 242,038 shares of company common stock, issued out of treasury stock, to certain employees through the company's Restricted Stock Plan, and recording deferred compensation of $6 million based on the market price per share of common stock on the dates of the awards, which averaged $23.90.
- In December 2004 repurchasing at a premium, $17 million of 5.75% notes, due November 15, 2006, with proceeds from the sale of Ginna.

NYSEG Financing Activities | In August 2004 NYSEG refunded an aggregate $204 million of fixed-rate tax-exempt pollution control notes with interest rates ranging from 5.70% to 6.05% with proceeds from the issuance of $204 million of multi-mode tax-exempt pollution control notes with due dates ranging from 2027 to 2034.

RG&E Financing Activities | RG&E used proceeds from the sale of Ginna to significantly reduce its capitalization. The following long-term debt and preferred stock redemptions were financed through available cash and RG&E's short-term credit facility. The short-term credit facility was repaid with proceeds from the sale of Ginna. Any premiums paid to refund the debt and preferred stock are being amortized over five years in accordance with RG&E's Electric and Natural Gas Rate Agreements.

In May 2004 RG&E redeemed, at a premium, the following first mortgage bonds:

- $40 million of 7.45% Series due July 2023.
- $33 million of 7.64% Series due March 2023.
- $5 million of 7.66% Series due March 2023.
- $12 million of 7.67% Series due March 2023.

In March and May 2004 RG&E redeemed the following issues of preferred stock:

- $25 million of 6.60% Series V at par.*
- $12 million of 4% Series F at a premium.
- $8 million of 4.10% Series H at a premium.
- $6 million of 4 3/4% Series I at a premium.
- $5 million of 4.10% Series J at a premium.
- $6 million of 4.95% Series K at a premium.
- $10 million of 4.55% Series M at a premium.

*The Series V preferred stock was mandatorily redeemable and was classified as a liability as of July 1, 2003, in accordance with Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.

In August 2004 RG&E refunded an aggregate $60 million of secured fixed-rate tax-exempt pollution control notes with interest rates ranging from 6.35% to 6.5% with proceeds from the issuance of $60 million of secured multi-mode tax-exempt pollution control notes due 2032.

In September 2004 RG&E repurchased at a premium $39 million of Series TT 6.95% first mortgage bonds, due April 1, 2011, with proceeds from the sale of Ginna.

Available Sources of Funding

The company and its subsidiaries have revolving credit agreements with various expiration dates from 2005 through 2009 and pay fees in lieu of compensating balances in connection with those credit agreements. The agreements provided for maximum borrowings of $740 million at December 31, 2004, and $700 million at December 31, 2003.

The company and its subsidiaries use short-term, unsecured notes and drawings on their credit agreements (see above) to finance certain refundings and for other corporate purposes. There was $206 million of such short-term debt outstanding at December 31, 2004, and $308 million outstanding at December 31, 2003. The weighted-average interest rate on short-term debt was 2.8% at December 31, 2004, and 1.8% at December 31, 2003.

The company filed a shelf registration statement with the Securities and Exchange Commission in June 2003 to sell up to $1 billion in an unspecified combination of debt, preferred stock, common stock and trust preferred securities. The company plans to use the net proceeds from the sale of securities under this shelf registration, if any, for general corporate purposes, such as the repurchase or refinancing of securities. The company currently has $805 million available under the shelf registration statement.

Quantitative and Qualitative Disclosures About Market Risk

Market risk represents the risk of changes in value of a financial or commodity instrument, derivative or nonderivative, caused by fluctuations in interest rates and commodity prices. The following discussion of the company's risk management activities includes "forward-looking" statements that involve risks and uncertainties. Actual results could differ materially from those contemplated in the "forward-looking" statements. The company handles market risks in accordance with established policies, which may include various offsetting, nonspeculative derivative transactions. (See Note 1 to the Consolidated Financial Statements.)

The financial instruments held or issued by the company are for purposes other than trading or speculation. Quantitative and qualitative disclosures are discussed as they relate to the following market risk exposure categories: Interest Rate Risk, Commodity Price Risk and Other Market Risk.

Interest Rate Risk | The company is exposed to risk resulting from interest rate changes on its variable-rate debt and commercial paper. The company uses interest rate swap agreements to manage the risk of increases in variable interest rates and to maintain desired fixed-to-floating rate ratios. Amounts paid and received under those agreements are recorded as adjustments to the interest expense of the specific debt issues. After giving effect to those agreements the company estimates that, at December 31, 2004, a 1% change in average interest rates would change annual interest expense for variable-rate debt by about $8.4 million. Pursuant to its current rate plans, RG&E defers any changes in variable-rate interest expense. (See Notes 7, 8 and 13 to the Consolidated Financial Statements.)

The company also uses derivative instruments to mitigate risk resulting from interest rate changes on future financings. Amounts paid or received under those instruments are amortized to interest expense over the life of the corresponding financing.

Commodity Price Risk | Commodity price risk is a significant issue for the company due to volatility experienced in the electric wholesale markets. The company manages this risk through a combination of regulatory mechanisms, such as allowing for the pass-through of the market price of electricity to customers, and through comprehensive risk management processes. These measures mitigate the company's commodity price exposure, but do not completely eliminate it.

The company uses electricity contracts, both physical and financial, to manage fluctuations in the cost of electricity. The cost or benefit of those contracts is included in the amount expensed for electricity purchased when the electricity is sold.

NYSEG's current electric rate plan offers retail customers choice in their electricity supply including fixed and variable rate options, and an option to purchase electricity supply from an ESCO. Approximately 40% of NYSEG's total electric load is now provided by an ESCO or at the market price. NYSEG's exposure to fluctuations in the market price of electricity is limited to the load required to serve those customers who select the bundled rate option, which combines delivery and supply service at a fixed price. NYSEG actively hedges the load required to serve customers who select the bundled rate option. As of January 30, 2005, NYSEG's load was 99% hedged for on-peak periods and 97% hedged for off-peak periods in 2005. A fluctuation of $1.00 per megawatt-hour in the price of electricity would change earnings less than $250,000 in 2005. The percentage of NYSEG's hedged load is based on NYSEG's load forecasts, which include certain assumptions such as historical weather patterns. Actual results could differ as a result of changes in the load compared to the load forecast.

RG&E's current electric rate plan offers retail customers choice in their electricity supply including fixed and variable rate options, and an option to purchase electricity supply from an ESCO. Approximately 75% of RG&E's total electric load is now provided by an ESCO or at the market price. Two of Energy East's affiliates offer ESCO service and are among the options that NYSEG and RG&E customers have for their electricity supply. RG&E's exposure to fluctuations in the market price of electricity is limited to the load required to serve those customers who select the fixed rate option, which combines delivery and supply service at a fixed price. Owned electric generation and long-term supply contracts significantly reduce RG&E's exposure to market fluctuations for procurement of its electric supply. RG&E actively hedges the load required to serve customers who select the fixed rate option. As of January 30, 2005, RG&E's load was 98% hedged for on-peak periods and fully hedged for off-peak periods in 2005. A fluctuation of $1.00 per megawatt-hour in the price of on-peak electricity would change earnings less than $100,000 in 2005. The percentage of RG&E's hedged load is based on RG&E's load forecasts, which include certain assumptions such as historical weather patterns. Actual results could differ as a result of changes in the load compared to the load forecast.

While owned generation provides RG&E with a natural hedge against electric price risk, it also subjects it to operating risk. Operating risk is managed through a combination of strict operating and maintenance practices.

Although CMP has no long-term supply responsibilities, the MPUC can mandate that CMP be a standard-offer provider of electricity supply service for retail customers if the MPUC should deem bids by competitive suppliers to be unacceptable. Competitive suppliers have provided all standard-offer obligations in CMP's service territory since March 2002. (See CMP Electricity Supply Responsibility.) In December 2004 the MPUC chose CEC Group as the new supplier of standard-offer electricity to CMP's residential and small commercial customers (100% for the first year, 66.6% for the second year and 33.3% for the third year) for a three-year period beginning March 1, 2005. CMP no longer owns any generating assets but retains its power entitlements under long-term contracts with NUGs and a power purchase contract with Vermont Yankee. In December 2004 the MPUC approved CMP's sale of those entitlements to CEC Group for one to three years and the residential and small commercial standard-offer is linked to the sale of CMP's entitlements.

In January 2005 the MPUC chose suppliers of standard-offer electricity for the six months beginning March 1, 2005, for CMP's medium and large customer classes. The MPUC will hold another auction to determine new suppliers for these classes of customers for the period beginning September 2005.

All of Energy East's natural gas utilities have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk.

NYSEG and RG&E use natural gas futures and forwards to manage fluctuations in natural gas commodity prices and provide price stability to customers. The cost or benefit of natural gas futures and forwards is included in the commodity cost, which is passed on to customers when the related sales commitments are fulfilled.

Other Market Risk | The company's pension plan assets are primarily made up of equity and fixed income investments. Fluctuations in those markets as well as changes in interest rates cause the company to recognize increased or decreased pension income or expense. If the expected return on plan assets were to change by 1/4%, pension income would change by approximately $6 million. A change of 1/4% in the discount rate would result in a change in pension income of a similar amount. Under the current rate plans for RG&E and NYSEG, changes in pension income resulting from changes in market conditions are deferred for RG&E's electric and natural gas delivery businesses and for NYSEG's natural gas delivery business. (See Note 16 to the Consolidated Financial Statements.)

Forward-looking Statements

The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements in certain circumstances. This Annual Report contains certain forward-looking statements that are based upon management's current expectations and information that is currently available. Whenever used in this report, the words "estimate," "expect," "believe," "anticipate," or similar expressions are intended to identify such forward-looking statements.

In addition to the assumptions and other factors referred to specifically in connection with such statements, factors that involve risks and uncertainties and that could cause actual results to differ materially from those contemplated in any forward-looking statements include, among others: the deregulation and continued regulatory unbundling of a vertically integrated industry; the company's ability to compete in the rapidly changing and increasingly competitive electricity and/or natural gas utility markets; regulatory uncertainty in a politically-charged environment of changing energy prices; the operation of the NYISO and ISO New England; the operation of a New England RTO; the ability to recover nonutility generator and other costs; changes in fuel supply or cost and the success of strategies to satisfy power requirements; the company's ability to expand its products and services, including its energy infrastructure in the Northeast; the company's ability to integrate the operations of Berkshire Energy Resources, CMP Group, Connecticut Energy Corporation, CTG Resources, Inc. and RGS Energy; the company's ability to maintain enterprise-wide integration synergies; market risk; the ability to obtain adequate and timely rate relief and/or the extension of current rate plans; the continuation of fixed price supply programs at current levels; nuclear or environmental incidents; legal or administrative proceedings; changes in the cost or availability of capital; growth in the areas in which the company is doing business; weather variations affecting customer energy usage; authoritative accounting guidance; acts of terrorists; the inability of the company's internal control framework to provide absolute assurance that all incidents of fraud or error will be detected and prevented; and other considerations, such as the effect of the volatility in the equity and fixed income markets on pension benefit cost, that may be disclosed from time to time in the company's publicly disseminated documents and filings. The company undertakes no obligation to publicly update any forward-looking statements, whether as a result of new information, future events or otherwise.

Results of Operations

	2004	2003	2002
(Thousands, except per share amounts)			
Operating Revenues	**$4,756,692**	$4,514,490	$3,778,026
Operating Expenses	**$4,006,739**	$3,862,678	$3,183,393
Operating Income	**$749,953**	$651,812	$594,633
Interest Charges, Net and Preferred Stock Dividends of Subsidiaries	**$280,581**	$303,799	$288,290
Income Taxes	**$251,444**	$128,663	$100,277
Income from Continuing Operations	**$237,621**	$208,490	$189,929
Net Income	**$229,337**	$210,446	$188,603
Average Common Shares Outstanding, basic	**146,305**	145,535	131,117
Earnings Per Share from Continuing Operations, basic	**$1.63**	$1.43	$1.45
Earnings Per Share, basic	**$1.57**	$1.45	$1.44

Due to the merger completed on June 28, 2002, the company's results of operations include RGS Energy beginning with July 2002.

2004 Earnings Per Share

Earnings per share from continuing operations, basic for 2004 increased 20 cents compared to 2003 primarily because of:

- Additional earnings of 16 cents per share as a result of one-time and ongoing effects from RG&E's 2004 Electric and Natural Gas Rate Agreements, including ratemaking treatment for the sale of Ginna. The one-time effects, which added 7 cents per share, include the flow-through of excess deferred taxes and investment tax credits and the settlement of certain regulatory assets and liabilities established pending regulatory determination. Ongoing effects added 9 cents per share to earnings, and include increases as a result of RG&E's electric retail access surcharge and natural gas merchant function charge, and annual credits from the ASGA as provided in RG&E's Electric Rate Agreement.
- An increase of 10 cents per share from lower financing costs and savings from integration and efficiency initiatives. Financing costs decreased principally due to redemptions and refinancings of first mortgage bonds and preferred stock of subsidiaries funded, in part, by proceeds from the sale of Ginna, as well as the sale of certain nonutility businesses in 2003 and 2004 and internally generated funds.
- The effect of a loss on retirement of debt that reduced earnings 9 cents per share in 2003.

Those increases were partially offset by:

- Lower income from natural gas operations, due in part to a 2% drop in retail sales, which reduced earnings 7 cents per share.
- A reduction of 6 cents per share due to cumulative stock-based compensation because of changes in the market value of Energy East common stock during 2004.
- A decrease of 3 cents per share because of higher depreciation expense due to electric plant additions, excluding depreciation related to Ginna.

2003 Earnings Per Share

Earnings from continuing operations for 2003 decreased 2 cents per share compared to 2002. The per share amounts were affected by an increase in average shares outstanding as a result of the merger with RGS Energy completed in June 2002. Major factors influencing the decrease include:

- A decline of 15 cents per share due to lower noncash pension income.
- An electric rate reduction of $205 million ordered by the NYPSC for NYSEG, effective March 1, 2002, that reduced 2003 earnings 11 cents per share.
- A higher effective tax rate due to changes in estimates of income tax accruals for both 2002 and 2003 that reduced earnings 9 cents per share.
- A decrease of 4 cents per share because of lower transmission revenue.
- Higher purchased energy costs that reduced earnings 3 cents per share.
- A net decrease of 2 cents per share due to losses on the retirement of debt, reflecting a loss of 9 cents per share in 2003, partially offset by the effect of a loss of 7 cents per share in 2002.

Those decreases were partially offset by:

- An increase of 8 cents per share for higher electric and natural gas deliveries (primarily residential and commercial) due in part to colder winter weather in the first quarter of 2003 partially offset by unfavorable weather in the third and fourth quarters of 2003.
- Cost control efforts and synergy efficiencies, including lower interest charges, that added 8 cents per share to earnings.
- The effect of restructuring expenses that reduced earnings 19 cents per share in 2002.
- The effect of a writedown of the company's investment in NEON Communications that reduced earnings 6 cents per share in 2002.

Other Items

Other Operating Expenses | Net periodic pension income is included in other operating expenses and reduces the amount of expense that would otherwise be reported. Other operating expenses would have been $11 million lower for 2004 and $30 million lower for 2003 if net periodic pension income for each of those years had not decreased compared to the prior year.

($ in Millions)	**2004**	2003	2002
Net periodic pension income	**$29**	$40	$70
As a percent of net income	**8%**	11%	22%

Other (Income) and Other Deductions | (See Note 1 to the Consolidated Financial Statements.) The changes for 2004 include:

- A $14 million increase in Other (income), primarily due to higher interest income of $3 million and a $6 million increase as a result of RG&E's 2004 Electric Rate Agreement.
- A $17 million decrease in Other deductions primarily due to the effect of a $23 million loss on retirement of debt in 2003.

The changes for 2003 include:

- A $3 million decrease in Other (income) as a result of lower interest income.
- A $3 million increase in Other deductions primarily due to the net effects of losses on retirement of debt in 2003 and 2002.

Interest Charges, Net and Preferred Stock Dividends of Subsidiaries | Interest charges, net and preferred stock dividends of subsidiaries decreased $23 million in 2004. In July 2003 the company began to recognize as interest expense certain distributions that it had previously recognized as preferred stock dividends. The combined decrease is primarily due to:

- Refinancings of long-term debt at lower interest rates.
- Redemptions and repurchases of first mortgage bonds and preferred stock of subsidiaries.

Interest charges increased $29 million in 2003 due to:

- A $27 million increase due to the addition of RG&E's interest expense for a full year.
- A $15 million increase because the company began to recognize as interest expense effective July 1, 2003, certain distributions that it had previously recognized as preferred stock dividends. There was a corresponding decrease in preferred stock dividends of subsidiaries in 2003 because of this change.
- A $14 million increase that reflects borrowings in June 2002 to finance the company's merger transaction with RGS Energy.

Those increases were partially offset by:

- Savings of $26 million primarily due to refinancings and repayments of first mortgage bonds.

Income Tax Expense | The effective tax rate for continuing operations was 51% in 2004, 36% in 2003 and 31% in 2002.

The increase in the 2004 effective tax rate was primarily due to:

- Regulatory treatment of RG&E's deferred gain on the sale of Ginna. RG&E recorded pretax income of $112 million and income tax expense of $112 million. (See Note 2 to the Consolidated Financial Statements.)
- Increases due to changes in estimates of prior year taxes of $3 million.

The effective tax rate increased in 2003 primarily due to:

- The recognition as interest expense effective July 1, 2003, of $15 million of distributions that the company had previously recognized as preferred stock dividends.
- The effect of depreciation and amortization not normalized related to RG&E for a full year in 2003 compared to six months in 2002. (See Note 6 to the Consolidated Financial Statements.)

Operating Results for the Electric Delivery Business

	2004	2003	2002
(Thousands)			
Deliveries – Megawatt-hours			
Retail	**31,019**	30,593	26,869
Wholesale	**7,855**	5,734	5,330
Operating Revenues	**$2,781,322**	$2,758,695	$2,568,247
Electricity purchased and fuel used in generation	**$1,321,081**	$1,192,397	$1,192,828
Other operating and maintenance expenses	**$667,503**	$767,150	$593,406
Depreciation and amortization	**$196,782**	$211,120	$162,515
Operating Expenses	**$2,227,450**	$2,311,801	$2,119,218
Operating Income	**$553,872**	$446,894	$449,029

Operating Revenues | The $23 million increase in 2004 operating revenues was primarily the result of:

- Higher wholesale sales of $68 million primarily for NYSEG. The increase reflected higher market prices and increased activity to mitigate supply prices.
- An increase of $5 million due to higher retail deliveries.
- Certain provisions of RG&E's Electric Rate Agreement that added $10 million to revenues, including $4 million from a retail access surcharge and $6 million as a result of various credits from the ASGA.

Those increases were partially offset by:

- ▶ A decrease of $27 million due to rate reductions for CMP reflecting lower stranded costs and lower amortization of storm and demand-side management (DSM) costs.
- ▶ A $19 million decrease due to a change in market structure for RG&E that allows ESCOs to provide electricity, resulting in lower retail revenues partially offset by higher wholesale revenues.
- ▶ A $15 million decrease for NYSEG due to reductions in the amount of electricity supplied by NYSEG under its various commodity options.

Operating revenues for 2003 increased $190 million primarily as a result of:

- ▶ The addition of RG&E delivery revenues of $343 million.

That increase was partially offset by:

- ▶ A $35 million decrease for RG&E due to lower retail deliveries because of cooler summer weather.
- ▶ A decrease of $24 million due to the combined effects of NYSEG's rate reduction, effective March 2002, and customers choosing alternate suppliers.
- ▶ A reduction of $46 million due to the elimination in 2002 of the partial amortization of an ASGA that was used to fund a portion of NYSEG's rate reduction effective March 2002.
- ▶ A decrease of $18 million because CMP is no longer the standard-offer provider for the supply of electricity effective March 2002.
- ▶ An $11 million decrease due to lower transmission revenues.

Operating Expenses | The $84 million decrease in operating expenses for 2004 was primarily the result of:

- ▶ A net $112 million decrease resulting from the regulatory treatment of RG&E's gain on the sale of Ginna, which includes RG&E's recognition of a $341 million pretax gain partially offset by the after-tax deferral of the gain of $229 million.
- ▶ Reduced operating costs of $73 million, including reduced depreciation and decommissioning expenses of $32 million, as a result of the sale of Ginna.
- ▶ A $10 million decrease in RG&E's operating and maintenance costs because of certain deferral petitions that were resolved as part of RG&E's Electric Rate Agreement.
- ▶ Lower operating costs of $5 million because CMP completed its amortization of storm and DSM costs as of the end of June 2004.

Those decreases were partially offset by:

- ▶ Increased purchased power costs of $91 million for RG&E due to the purchases from Ginna beginning in June 2004.
- ▶ A $42 million increase due to higher purchased power costs, primarily for increased wholesale sales.
- ▶ Higher depreciation of $7 million due to significant additions to plant in service and the accelerated depreciation of legacy accounting systems that were replaced in 2004.

Operating expenses for 2003 increased $193 million primarily as a result of:

- ▶ The addition of RG&E operating expenses of $282 million.

That increase was partially offset by decreases in purchased power costs, including:

- ▶ A $53 million decrease due to the net effect of customers choosing alternate suppliers and increases caused by both higher market prices and higher retail deliveries because of colder winter weather.
- ▶ An $18 million decrease because CMP is no longer the standard-offer provider for the supply of electricity effective March 2002.
- ▶ Lower NUG power purchases of $12 million.

Operating Results for the Natural Gas Delivery Business

(Thousands)	2004	2003	2002
Deliveries – Dekatherms			
Retail	**208,444**	212,745	181,859
Wholesale	**1,593**	5,360	7,074
Operating Revenues	**$1,549,150**	$1,462,127	$1,032,539
Operating Expenses	**$1,366,486**	$1,263,182	$882,883
Operating Income	**$182,664**	$198,945	$149,656

Operating Revenues | Operating revenues for 2004 increased $87 million primarily as a result of:

- Higher market prices of natural gas of $120 million that were passed on to customers.

That increase was partially offset by:

- Lower retail deliveries of $12 million due to warmer winter weather in the first quarter of 2004, partially offset by higher deliveries in the fourth quarter of 2004.
- Lower transportation revenue and wholesale entitlements of $28 million.

2003 operating revenues increased $430 million primarily as a result of:

- The addition of RG&E delivery revenues of $213 million.
- A $50 million increase due to higher retail deliveries because of colder winter weather in the first quarter of 2003.
- An increase of $158 million largely due to higher market prices of natural gas that were passed on to customers.

Operating Expenses | The $103 million increase in 2004 operating expenses was primarily the result of:

- Higher natural gas prices of $120 million because of market conditions.

That increase was partially offset by lower natural gas purchases, including:

- Decreases of $6 million due to lower retail deliveries and $16 million due to lower wholesale sales.

Operating expenses for 2003 increased $380 million primarily as a result of:

- The addition of RG&E operating expenses of $178 million.
- Higher natural gas costs of $171 million due to market conditions net of the effect of various rate case deferrals.
- A $28 million increase in natural gas purchases due to higher retail deliveries because of colder winter weather in the first quarter of 2003.

Energy East Corporation
Consolidated Balance Sheets

December 31	2004	2003
(Thousands)		
Assets		
Current Assets		
Cash and cash equivalents	**$247,120**	$147,869
Accounts receivable, net	**821,556**	753,327
Fuel, at average cost	**198,640**	159,163
Materials and supplies, at average cost	**26,592**	22,490
Accumulated deferred income tax benefits, net	**33,969**	26,262
Prepayments and other current assets	**95,629**	122,876
Total Current Assets	**1,423,506**	1,231,987
Utility Plant, at Original Cost		
Electric	**5,282,828**	5,992,001
Natural gas	**2,493,455**	2,405,795
Common	**420,372**	361,737
	8,196,655	8,759,533
Less accumulated depreciation	**2,602,013**	3,216,927
Net Utility Plant in Service	**5,594,642**	5,542,606
Construction work in progress	**67,526**	235,503
Total Utility Plant	**5,662,168**	5,778,109
Other Property and Investments, Net	**190,148**	465,624
Regulatory and Other Assets		
Regulatory assets		
Nuclear plant obligations	**356,072**	414,699
Unfunded future income taxes	**115,446**	254,978
Unamortized loss on debt reacquisitions	**58,345**	47,509
Environmental remediation costs	**122,052**	122,846
Nonutility generator termination agreements	**96,158**	106,631
Asset retirement obligation	**-**	163,530
Other	**419,214**	431,175
Total regulatory assets	**1,167,287**	1,541,368
Other assets		
Goodwill, net	**1,525,353**	1,533,123
Prepaid pension benefits	**657,402**	608,933
Other	**170,249**	171,297
Total other assets	**2,353,004**	2,313,353
Total Regulatory and Other Assets	**3,520,291**	3,854,721
Total Assets	**$10,796,113**	$11,330,441

The notes on pages 29 through 51 are an integral part of the consolidated financial statements.

Energy East Corporation
Consolidated Balance Sheets

December 31	**2004**	2003
(Thousands)		
Liabilities		
Current Liabilities		
Current portion of preferred stock of subsidiary subject to mandatory redemption requirements	**–**	$1,250
Current portion of long-term debt	**$59,231**	30,989
Notes payable	**206,472**	308,404
Accounts payable and accrued liabilities	**454,876**	348,297
Interest accrued	**43,469**	48,989
Taxes accrued	**8,568**	49,605
Other	**184,227**	193,630
Total Current Liabilities	**956,843**	981,164
Regulatory and Other Liabilities		
Regulatory liabilities		
Accrued removal obligation	**762,520**	731,621
Deferred income taxes	**21,487**	181,211
Gain on sale of generation assets	**233,378**	129,640
Pension benefits	**25,354**	51,970
Other	**107,932**	106,061
Total regulatory liabilities	**1,150,671**	1,200,503
Other liabilities		
Deferred income taxes	**973,599**	853,489
Nuclear plant obligations	**251,753**	277,643
Other postretirement benefits	**419,885**	408,903
Asset retirement obligation	**2,378**	437,076
Environmental remediation costs	**150,263**	145,446
Other	**415,107**	344,952
Total other liabilities	**2,212,985**	2,467,509
Total Regulatory and Other Liabilities	**3,363,656**	3,668,012
Debt owed to subsidiary holding solely parent debentures	**355,670**	355,670
Preferred stock of subsidiary subject to mandatory redemption requirements	**–**	23,750
Other long-term debt	**3,442,015**	3,638,426
Total long-term debt	**3,797,685**	4,017,846
Total Liabilities	**8,118,184**	8,667,022
Commitments and Contingencies	**–**	–
Preferred Stock of Subsidiaries		
Redeemable solely at the option of subsidiaries	**46,671**	93,677
Common Stock Equity		
Common stock ($.01 par value, 300,000 shares authorized, 147,118 shares outstanding at December 31, 2004, and 146,262 shares outstanding at December 31, 2003)	**1,471**	1,463
Capital in excess of par value	**1,477,518**	1,456,220
Retained earnings	**1,201,533**	1,126,457
Accumulated other comprehensive income (loss)	**(43,561)**	(11,214)
Deferred compensation	**(5,020)**	(2,820)
Treasury stock, at cost (29 shares at December 31, 2004, and 13 shares at December 31, 2003)	**(683)**	(364)
Total Common Stock Equity	**2,631,258**	2,569,742
Total Liabilities and Stockholders' Equity	**$10,796,113**	$11,330,441

The notes on pages 29 through 51 are an integral part of the consolidated financial statements.

Energy East Corporation
Consolidated Statements of Income

Year Ended December 31	2004	2003	2002
(Thousands, except per share amounts)			
Operating Revenues			
Sales and services	**$4,756,692**	$4,514,490	$3,778,026
Operating Expenses			
Electricity purchased and fuel used in generation	**1,570,410**	1,338,369	1,276,087
Natural gas purchased	**1,030,314**	939,464	569,794
Other operating expenses	**790,926**	813,133	667,190
Maintenance	**181,725**	203,042	160,291
Depreciation and amortization	**292,458**	299,432	240,306
Other taxes	**252,860**	269,238	229,158
Restructuring expenses	**–**	–	40,567
Gain on sale of generation assets	**(340,739)**	–	–
Deferral of asset sale gain	**228,785**	–	–
Total Operating Expenses	**4,006,739**	3,862,678	3,183,393
Operating Income	**749,953**	651,812	594,633
Writedown of Investment	**–**	–	12,209
Other (Income)	**(35,497)**	(21,852)	(25,332)
Other Deductions	**15,804**	32,712	29,260
Interest Charges, Net	**276,890**	284,790	256,161
Preferred Stock Dividends of Subsidiaries	**3,691**	19,009	32,129
Income from Continuing Operations Before Income Taxes	**489,065**	337,153	290,206
Income Taxes	**251,444**	128,663	100,277
Income from Continuing Operations	**237,621**	208,490	189,929
Discontinued Operations			
Loss from discontinued operations (including loss on disposal of $(7,565) in 2004 and $(13,360) in 2003)	**(7,108)**	(12,032)	(3,079)
Income taxes (benefits)	**1,176**	(13,988)	(1,753)
(Loss) Income from Discontinued Operations	**(8,284)**	1,956	(1,326)
Net Income	**$229,337**	$210,446	$188,603
Earnings Per Share from Continuing Operations, basic	**$1.63**	$1.43	$1.45
Earnings Per Share from Continuing Operations, diluted	**$1.62**	$1.43	$1.45
(Loss) Earnings Per Share from Discontinued Operations, basic	**$(.06)**	$.02	$(.01)
(Loss) Earnings Per Share from Discontinued Operations, diluted	**$(.06)**	$.01	$(.01)
Earnings Per Share, basic	**$1.57**	$1.45	$1.44
Earnings Per Share, diluted	**$1.56**	$1.44	$1.44
Average Common Shares Outstanding, basic	**146,305**	145,535	131,117
Average Common Shares Outstanding, diluted	**146,713**	145,730	131,117

The notes on pages 29 through 51 are an integral part of the consolidated financial statements.

Energy East Corporation
Consolidated Statements of Cash Flows

Year Ended December 31	2004	2003	2002
(Thousands)			
Operating Activities			
Net income	**$229,337**	$210,446	$188,603
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization	**377,181**	419,237	255,782
Income taxes and investment tax credits deferred, net	**83,327**	103,236	43,564
Income taxes related to gain on sale of generation assets	**111,954**	–	–
Restructuring expenses	**–**	–	40,567
Gain on sale of generation assets	**(340,739)**	–	–
Deferral of asset sale gain	**228,785**	–	–
Pension income	**(28,808)**	(40,128)	(69,860)
Writedown of investment	**–**	–	12,209
Changes in current operating assets and liabilities			
Accounts receivable, net	**(70,067)**	(56,188)	(24,247)
Inventory	**(43,579)**	(50,775)	6,111
Prepayments and other current assets	**1,326**	8,732	(3,998)
Accounts payable and accrued liabilities	**91,527**	(9,999)	46,473
Taxes accrued	**(91,840)**	(15,315)	23,016
Customer refund	**(58,219)**	–	–
Other current liabilities	**(37,213)**	15,941	5,866
Pension contributions	**(19,661)**	(20,006)	(329)
Other assets	**(82,874)**	(114,466)	(66,279)
Other liabilities	**(11,337)**	25,052	(6,120)
Net Cash Provided by Operating Activities	**339,100**	475,767	451,358
Investing Activities			
Sale of generation assets	**453,678**	–	59,442
Excess decommissioning funds retained	**76,593**	–	–
Acquisitions, net of cash acquired	**–**	–	(681,397)
Utility plant additions	**(299,263)**	(289,320)	(224,450)
Other property and investments additions	**(5,623)**	(39,060)	(29,177)
Other property and investments sold	**6,161**	72,478	12,138
Other	**1,062**	(6,678)	1,490
Net Cash Provided by (Used in) Investing Activities	**232,608**	(262,580)	(861,954)
Financing Activities			
Issuance of common stock	**3,083**	4,234	2,574
Repurchase of common stock	**(6,071)**	–	(2,139)
Repayments of first mortgage bonds and preferred stock of subsidiaries, including net premiums	**(201,005)**	(242,066)	(435,720)
Long-term note issuances	**212,975**	504,769	767,807
Long-term note repayments	**(249,025)**	(488,654)	(97,124)
Notes payable three months or less, net	**(92,932)**	(7,044)	166,702
Notes payable issuances	**4,000**	11,000	28,400
Notes payable repayments	**(13,000)**	(17,750)	(50,154)
Book overdraft	**5,892**	–	–
Dividends on common stock	**(136,374)**	(127,940)	(110,186)
Net Cash (Used in) Provided by Financing Activities	**(472,457)**	(363,451)	270,160
Net Increase (Decrease) in Cash and Cash Equivalents	**99,251**	(150,264)	(140,436)
Cash and Cash Equivalents, Beginning of Year	**147,869**	298,133	438,569
Cash and Cash Equivalents, End of Year	**$247,120**	$147,869	$298,133

The notes on pages 29 through 51 are an integral part of the consolidated financial statements.

Energy East Corporation
Consolidated Statements of Changes in Common Stock Equity

(Thousands, except per share amounts)	Common Stock Outstanding $.01 Par Value Shares	Common Stock Outstanding $.01 Par Value Amount	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Treasury Stock	Total
Balance, January 1, 2002	116,718	$1,182	$839,673	$998,281	$(22,335)	–	$(38,940)	$1,777,861
Net income				188,603				188,603
Other comprehensive income, net of tax					(11,832)			(11,832)
Comprehensive income								176,771
Amortization of excess capital over par			593					593
Common stock dividends declared ($.96 per share)				(125,456)				(125,456)
Common stock issued – merger transaction	27,509	275	611,807					612,082
Common stock issued – Investor Services Program	853		17,844					17,844
Common stock repurchased	(114)	(1)	(2,138)					(2,139)
Capital stock issue expense			(52)					(52)
Treasury stock transactions, net		(1)	(23,171)				23,172	–
Amortization of capital stock issue expense			385					385
Balance, December 31, 2002	144,966	1,455	1,444,941	1,061,428	(34,167)	–	(15,768)	2,457,889
Net income				210,446				210,446
Other comprehensive income, net of tax					22,953			22,953
Comprehensive income								233,399
Amortization of excess capital over par			141					141
Common stock dividends declared ($1.00 per share)				(145,417)				(145,417)
Common stock issued – Investor Services Program	1,064	8	21,703					21,711
Common stock issued – restricted stock plan	229		(1,893)			$(4,401)	6,294	–
Amortization of deferred compensation under restricted stock plan						1,581		1,581
Capital stock issue expense			(11)					(11)
Treasury stock transactions, net	3		(9,046)				9,110	64
Amortization of capital stock issue expense			385					385
Balance, December 31, 2003	146,262	1,463	1,456,220	1,126,457	(11,214)	(2,820)	(364)	2,569,742
Net income				229,337				229,337
Other comprehensive income, net of tax					(32,347)			(32,347)
Comprehensive income								196,990
Common stock dividends declared ($1.055 per share)				(154,261)				(154,261)
Common stock issued – Investor Services Program	872	8	20,962					20,970
Common stock repurchased	(250)						(6,071)	(6,071)
Common stock issued – restricted stock plan	242		(132)			(5,784)	5,916	–
Amortization of deferred compensation under restricted stock plan						3,584		3,584
Capital stock issue expense			(11)					(11)
Treasury stock transactions, net	(8)		94				(164)	(70)
Amortization of capital stock issue expense			385					385
Balance, December 31, 2004	147,118	$1,471	$1,477,518	$1,201,533	$(43,561)	$(5,020)	$(683)	$2,631,258

The notes on pages 29 through 51 are an integral part of the consolidated financial statements.

Energy East Corporation
Notes to Consolidated Financial Statements

NOTE 1 Significant Accounting Policies

Background | Energy East Corporation (Energy East or the company) is a registered public utility holding company under the Public Utility Holding Company Act of 1935. Energy East is a super-regional energy services and delivery company with operations in New York, Connecticut, Massachusetts, Maine and New Hampshire and corporate offices in New York and Maine. Its wholly-owned subsidiaries, and their principal operating utilities, are: Berkshire Energy Resources (Berkshire Energy) – The Berkshire Gas Company; CMP Group, Inc. (CMP Group) – Central Maine Power Company (CMP); Connecticut Energy Corporation (CNE) – The Southern Connecticut Gas Company (SCG); CTG Resources, Inc. (CTG Resources) – Connecticut Natural Gas Corporation (CNG); and RGS Energy Group, Inc. (RGS Energy) – New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E). Financial information for RGS Energy prior to July 1, 2002, does not include NYSEG since it was not a subsidiary of RGS Energy prior to that time.

Accounts receivable | Accounts receivable include unbilled revenues of $227 million at December 31, 2004, and $219 million at December 31, 2003, and are shown net of an allowance for doubtful accounts of $45 million at December 31, 2004, and $53 million at December 31, 2003. Accounts receivable do not bear interest, although late fees may be assessed. Bad debt expense was $45 million in 2004, $48 million in 2003 and $46 million in 2002. Bad debt expense for 2003 includes RGS Energy for a full year and for 2002 includes RGS Energy beginning July 1, 2002. The allowance for doubtful accounts is the company's best estimate of the amount of probable credit losses in its existing accounts receivable. The company determines the allowance based on experience for each region and operating segment and other economic data. Each month the company reviews its allowance for doubtful accounts and its past due accounts over 90 days and/or above a specified amount. The company reviews all other balances on a pooled basis by age and type of receivable. When the company believes that a receivable will not be recovered, it charges off the account balance against the allowance. The company does not have any off-balance-sheet credit exposure related to its customers.

Asset retirement obligation | In June 2001 the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (Statement 143). The company's adoption of Statement 143 as of January 1, 2003, did not have a material effect on its financial position or results of operations. In accordance with Statement 143, the company records the fair value of the liability for an asset retirement obligation in the period in which it is incurred and capitalizes the cost by increasing the carrying amount of the related long-lived asset. The company adjusts the liability to its present value periodically over time, and depreciates the capitalized cost over the useful life of the related asset. Upon settlement the company will either settle the obligation at its recorded amount or incur a gain or a loss. The company's rate-regulated entities will defer any timing differences between rate recovery and book expense as either a regulatory asset or a regulatory liability. The company's asset retirement obligation was $437 million at December 31, 2003. Substantially all of that amount was related to the Ginna nuclear generating station (Ginna), which was sold in June 2004 and reduced the asset retirement obligation $434 million. The remaining balance of $2 million primarily consists of obligations related to cast iron gas mains.

Statement 143 provides that if the requirements of Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (Statement 71) are met, a regulatory liability should be recognized for the difference between removal costs collected in rates and actual costs incurred. The company classifies these amounts as accrued removal obligations.

Basic and diluted earnings per share | Basic earnings per share (EPS) is determined by dividing net income by the weighted-average number of shares of common stock outstanding during the period. The weighted-average common shares outstanding for diluted EPS include the incremental effect of restricted stock and stock options issued and exclude stock options issued in tandem with stock appreciation rights (SARs). Historically, all stock options have been issued in tandem with SARs and substantially all stock option plan participants have exercised the SARs instead of the stock options. The numerator used in calculating both basic and diluted EPS for each period is reported net income.

The reconciliation of basic and dilutive average common shares for each period follows:

Year Ended December 31	2004	2003	2002
(Thousands)			
Basic average common shares outstanding	**146,305**	145,535	131,117
Restricted stock awards	**408**	195	–
Potentially dilutive common shares	**313**	197	215
Options issued with SARs	**(313)**	(197)	(215)
Dilutive average common shares outstanding	**146,713**	145,730	131,117

Options to purchase shares of common stock are excluded from the determination of EPS when the exercise price of the options is greater than the average market price of the common shares during the year. Shares excluded from the EPS calculation were: 2.0 million in 2004, 2.9 million in 2003 and 4.7 million in 2002. See Note 14 for additional information concerning Energy East's restricted stock.

Consolidated statements of cash flows | The company considers all highly liquid investments with a maturity date of three months or less when acquired to be cash equivalents and those investments are included in cash and cash equivalents.

Supplemental Disclosure of Cash Flows Information	2004	2003	2002
(Thousands)			
Cash paid during the year ended December 31:			
Interest, net of amounts capitalized	**$245,992**	$245,223	$238,305
Income taxes, net of benefits received	**$140,823**	$(12,879)	$54,418
Acquisition:			
Fair value of assets acquired	**–**	–	$3,264,093
Liabilities assumed	**–**	–	(1,826,528)
Preferred stock of subsidiary	**–**	–	(72,000)
Common stock issued	**–**	–	(612,082)
Cash acquired	**–**	–	(72,086)
Net cash paid for acquisition	**–**	–	$681,397

Decommissioning expense | Other operating expenses include nuclear decommissioning expense accruals, which resulted in corresponding decreases in the regulatory asset for the asset retirement obligation. As a result of the sale of Ginna on June 10, 2004, the company no longer has a decommissioning obligation and will not incur additional decommissioning expense. (See Note 11 for information about decommissioning expenses incurred by companies that are partially owned by CMP.)

Depreciation and amortization | The company determines depreciation expense substantially using straight-line rates, based on the average service lives of groups of depreciable property, which include estimated cost of removal, in service at each operating company. The weighted-average service lives of certain classifications of property are: transmission property – 54 years, distribution property – 47 years, generation property – 46 years, gas production property – 30 years, gas storage property – 33 years, and other property – 33 years. RG&E determines depreciation expense for the majority of its generation property using remaining service life rates, which include estimated cost of removal, based on operating license expiration or anticipated closing dates. The remaining service lives of RG&E's generation property range from 4 years for its coal station to 32 years for its hydroelectric stations. The company's depreciation accruals were equivalent to 3.3% of average depreciable property for 2004; 3.4% for 2003 and 3.5% for 2002, which was weighted for the effect of the merger completed in June 2002.

Estimates | Preparation of the consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of 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.

Goodwill | The excess of the cost over fair value of net assets of purchased businesses is recorded as goodwill. The company evaluates the carrying value of goodwill for impairment at least annually and on an interim basis if there are indications that goodwill might be impaired. An impairment may be recognized if the fair value of goodwill is less than its carrying value. (See Note 5.)

Income taxes | The company files a consolidated federal income tax return. Income taxes are allocated among Energy East and its subsidiaries in proportion to their contribution to consolidated taxable income. Securities and Exchange Commission regulations require that no Energy East subsidiary pay more income taxes than it would pay if a separate income tax return were to be filed. The determination and allocation of the income tax provision and its components are outlined and agreed to in the tax sharing agreements among Energy East and its subsidiaries.

Deferred income taxes reflect the effect of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and the amount recognized for tax purposes. Investment tax credits (ITCs) are amortized over the estimated lives of the related assets.

Other (Income) and Other Deductions |

Year Ended December 31	2004	2003	2002
(Thousands)			
Dividends	-	-	$(233)
Interest income	**$(10,953)**	$(8,059)	(18,799)
Allowance for funds used during construction	**(581)**	(1,965)	(1,401)
Gain from the sale of nonutility property	-	(212)	(104)
Earnings from equity investments	**(3,930)**	(4,702)	(4,631)
Miscellaneous	**(20,033)**	(6,914)	(164)
Total other (income)	**$(35,497)**	$(21,852)	$(25,332)
Retirement of debt	**$781**	$22,784	$16,145
Miscellaneous	**15,023**	9,928	13,115
Total other deductions	**$15,804**	$32,712	$29,260

Principles of consolidation | These financial statements consolidate the company's majority-owned subsidiaries after eliminating intercompany transactions, except variable interest entities for which the company is not the primary beneficiary.

Reclassifications | Certain amounts have been reclassified in the consolidated financial statements to conform to the 2004 presentation and to reflect discontinued operations.

Regulatory assets and liabilities | Pursuant to Statement 71 the company's operating utilities capitalize, as regulatory assets, incurred and accrued costs that are probable of recovery in future electric and natural gas rates. They also record, as regulatory liabilities, obligations to refund previously collected revenue or to spend revenue collected from customers on future costs.

Unfunded future income taxes and deferred income taxes are amortized as the related temporary differences reverse. Unamortized loss on debt reacquisitions is amortized over the lives of the related debt issues. Nuclear plant obligations, demand-side management program costs, gain on sale of generation assets, other regulatory assets and other regulatory liabilities are amortized over various periods in accordance with each company's current rate plans. The operating utilities earn a return on substantially all regulatory assets for which funds have been spent.

Revenue recognition | The company recognizes revenues upon delivery of energy and energy-related products and services to its customers.

Pursuant to Maine State Law, since March 1, 2000, CMP has been prohibited from selling power to its retail customers. CMP does not enter into any purchase and sales arrangements for power with ISO New England, Inc., the New England Power Pool, or any other independent system operator or similar entity. All of CMP's power entitlements under its nonutility generator (NUG) and other purchase power contracts are sold to unrelated third parties under bilateral contracts.

NYSEG and RG&E enter into power purchase and sales transactions with the New York Independent System Operator (NYISO). When NYSEG and RG&E sell electricity from owned generation to the NYISO, and subsequently repurchase electricity from the NYISO to serve their customers, they record the transactions on a net basis in their statements of income.

Risk management | All of Energy East's natural gas operating utilities have purchased gas adjustment clauses that allow them to recover through rates any changes in the market price of purchased natural gas, substantially eliminating their exposure to natural gas price risk. The company uses natural gas futures and forwards to manage fluctuations in natural gas commodity prices and provide price stability to customers. The company includes the cost or benefit of natural gas futures and forwards in the commodity cost when the related sales commitments are fulfilled.

The company uses electricity contracts, both physical and financial, to manage fluctuations in the cost of electricity. The company includes the cost or benefit of those contracts in the amount expensed for electricity purchased when the electricity is sold.

The company uses interest rate swap agreements to manage the risk of increases in variable interest rates and to maintain desired fixed-to-floating rate ratios. It records amounts paid and received under the agreements as adjustments to the interest expense of the specific debt issues. The company also uses derivative instruments to mitigate risk resulting from interest rate changes on future financings. The company amortizes amounts paid or received under those instruments to interest expense over the life of the corresponding financing.

The company does not hold or issue financial instruments for trading or speculative purposes.

The company recognizes the fair value of its natural gas futures and forwards, financial electricity contracts and interest rate agreements as other assets or other liabilities. The company had $37 million of derivative assets at December 31, 2004, including $9 million current and $28 million long-term. The company had $19 million of derivative liabilities at December 31, 2004, including $8 million current and $11 million long-term. At December 31, 2003, the company had $65 million of derivative assets and $3 million of derivative liabilities. All of the arrangements are designated as cash flow hedging instruments except for the company's fixed-to-floating interest rate swap agreements totaling $250 million, which are designated as fair value hedges. Changes in the fair value of the cash flow hedging instruments are recognized in other comprehensive income until the underlying transaction occurs. When the underlying transaction occurs, the amounts in accumulated other comprehensive income are reported on the consolidated statements of income. Changes in the fair value of the interest rate swap agreements are reported on the consolidated statements of income in the same period as the offsetting change in the fair value of the underlying debt instrument.

The company uses quoted market prices to determine the fair value of derivatives and adjusts for volatility and inflation when the period of the derivative exceeds the period for which market prices are readily available.

As of December 31, 2004, the maximum length of time over which the company is hedging its exposure to the variability in future cash flows for forecasted energy transactions is 60 months. The company estimates that losses of $8 million will be reclassified from accumulated other comprehensive income into earnings in 2005, as the underlying transactions occur.

The company has commodity purchase and sales contracts for both capacity and energy that have been designated and qualify for the normal purchases and normal sales exception in Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended.

FIN 46R | In December 2003 the FASB issued FASB Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin (ARB) No. 51 (FIN 46R), which addresses consolidation of variable interest entities. A variable interest entity is an entity that is not controllable through voting interests and/or in which the equity investor does not bear the residual economic risks and rewards. FIN 46R requires a business enterprise to consolidate a variable interest entity if that enterprise has a variable interest that will absorb a majority of the entity's expected losses. The company has a variable interest in Energy East Capital Trust I, a Delaware business trust that is a wholly-owned finance subsidiary of the company. Based on the trust's structure the company is not considered the primary beneficiary of the trust. The company had consolidated the trust under ARB No. 51. The company adopted the provisions of FIN 46R related to special purpose entities as of December 31, 2003, and ceased consolidating the trust as of December 31, 2003. As of March 31, 2004, the company was required to apply FIN 46R to all entities subject to the interpretation.

CMP and NYSEG have independent, ongoing, power purchase contracts with various NUGs. CMP and NYSEG were not involved in the formation of and do not have ownership interests in any NUGs. CMP and NYSEG evaluated each of their power purchase contracts with NUGs with respect to FIN 46R. Most of the power purchase contracts were determined not to be variable interests for one of the following reasons: the contract is based on a fixed price or a market price and there is no other involvement with the NUG, the contract is short-term in duration, the contract is for a minor portion of the NUG's capacity or the NUGs are either governmental organizations or individuals.

The companies are not able to apply FIN 46R to seven remaining NUGs because they are unable to obtain the information necessary to: (1) determine if the NUGs are variable interest entities, (2) determine if either CMP or NYSEG is a NUG's primary beneficiary or (3) perform the accounting required to consolidate any of the seven NUGs. CMP requested necessary information from four NUGs and NYSEG requested information from three NUGs. None of the NUGs provided the requested information. CMP and NYSEG will continue to make efforts to obtain information from the seven NUGs.

The companies purchase electricity from the seven NUGs at above-market prices. CMP and NYSEG are not exposed to any loss as a result of their involvement with NUGs because they are allowed to recover through rates the cost of their purchases. Also, they are under no obligation to a NUG if it decides not to operate for any reason. The combined contractual capacity for the four NUGs from which CMP purchases electricity is approximately 23 megawatts. CMP's purchases from the four NUGs totaled $11 million in 2004 and 2003, and $10 million in 2002. The combined contractual capacity for the three NUGs from which NYSEG purchases electricity is approximately 494 megawatts. NYSEG's purchases from the three NUGs totaled $314 million in 2004, $335 million in 2003 and $341 million in 2002.

CMP and NYSEG did not consolidate any NUGs at December 31, 2004 or 2003.

Stock-based compensation | As permitted by Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation (Statement 123), the company applies Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (APB 25), to account for its stock-based compensation to employees and uses the intrinsic value method to determine compensation related to its stock options issued in tandem with SARs. The company's stock-based compensation plans are described in more detail in Note 14. The company incurs a liability for its stock option plan awards because employees can compel the company to settle the awards in cash rather than by issuing equity instruments. Stock-based employee compensation expense, net of related tax effects, included in the company's net income was $13 million in 2004, $3 million in 2003 and $7 million in 2002. Those amounts are the same as they would have been if the fair value based method had been applied to all stock-based compensation awards consistent with Statement 123. Net income and basic and diluted EPS as reported for 2004, 2003 and 2002 are also the same as they would have been if the fair value based method had been applied to all awards.

Statement 123R | In December 2004 the FASB issued Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment (Statement 123R), which is a revision of Statement 123. Statement 123R requires a public entity to measure the cost of employee services that it receives in exchange for an award of equity instruments based on the grant-date fair value of the award and recognize that cost over the period during which the employee is required to provide service in exchange for the award. Statement 123R also requires a public entity to initially measure the cost of employee services received in exchange for an award of liability instruments based on the award's current fair value, subsequently remeasure the fair value of the award at each reporting date through the settlement date and recognize changes in fair value during the required service period as compensation cost over that period. Statement 123R is effective for public entities as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. The company plans to adopt Statement 123R effective July 1, 2005, and follow the modified version of prospective application. The weighted-average fair value per share of stock options awarded in 2004, 2003 and 2002 ranged between $2.93 and $3.91, and is not expected to change significantly for future awards of stock options. As required by Statement 123R, the company will no longer defer compensation cost for awards of restricted or nonvested stock and amortize the cost into compensation expense over the vesting period. Instead it will recognize the compensation cost of nonvested stock as described above for equity instruments. The company's adoption of Statement 123R is not expected to have a material effect on its financial position or results of operations.

Statement 150 | In May 2003 the FASB issued Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity (Statement 150). Statement 150 requires that certain financial instruments be classified as liabilities in statements of financial position. Under previous guidance such instruments could be classified as equity. Energy East and RG&E adopted Statement 150 as of July 1, 2003, and classified RG&E's $25 million of mandatorily redeemable preferred stock as a liability in their statements of financial position, which they had previously classified as equity. They also began to recognize as interest expense distributions that they had previously recognized as preferred stock dividends. The adoption of Statement 150 did not have a material effect on Energy East's or RG&E's financial position or results of operations.

Utility plant | The company charges repairs and minor replacements to operating expense accounts, and capitalizes renewals and betterments, including certain indirect costs. The original cost of utility plant retired or otherwise disposed of is charged to accumulated depreciation.

NOTE 2 Sale of Ginna

On June 10, 2004, RG&E sold Ginna to Constellation Generation Group, LLC (CGG) and received at closing $429 million in cash. On September 9, 2004, RG&E received an additional $25 million from CGG related to certain post-closing adjustments. As a result, the company's 2004 statement of income reflects a gain on the sale of Ginna of $341 million. The deferral of the asset sale gain, net of related taxes of $112 million, is $229 million.

RG&E's Electric Rate Agreement resolves all regulatory and ratemaking aspects related to the sale of Ginna, including providing for an Asset Sale Gain Account (ASGA) of $380 million after the post-closing adjustments, and addressing the disposition of the asset sale gain. Upon closing of the sale of Ginna, RG&E transferred $201 million of decommissioning funds to CGG, which will take responsibility for all future decommissioning funding. RG&E retained $77 million in excess decommissioning funds, which were credited to customers as part of the ASGA.

A summary of the effects of the sale of Ginna and the related ASGA follows (in thousands):

Cash proceeds	$453,678
Net book value of property sold, excluding decommissioning reserve	(187,545)
Decommissioning reserve	311,571
Decommissioning funds	(277,113)
Excess decommissioning funds retained	76,593
Miscellaneous assets and liabilities, including deferred selling costs	(36,445)
Gain on sale of generation assets	340,739
Income taxes payable	(111,954)
Deferral of asset sale gain	228,785
Regulatory liability equal to deferred income taxes on the deferred asset sale gain	150,765
Gain on sale of generation assets, deferred	$379,550

The ASGA was adjusted subsequent to the sale to reflect provisions of RG&E's Electric Rate Agreement, including refunds due to customers. Adjustments to the ASGA to reconcile to the deferred regulatory liability at December 31, 2004, are as follows (in thousands):

Gain on sale of generation assets, deferred	$379,550
Regulatory liability equal to deferred income taxes on the deferred asset sale gain	(150,765)
Refund to customers June 2004	(60,000)
Refund to customers March 2005, Other current liability	(25,000)
Other	(4,556)
Balance at December 31, 2004	$139,229

Nuclear insurance | Because of the sale of Ginna, RG&E is no longer subject to the Price-Anderson Act, which is a federal statute providing, among other things, a limit on the maximum liability of nuclear reactor owners for damages resulting from a single nuclear incident. Prior to the sale, RG&E carried the maximum available commercial insurance of $300 million and participated in a mandatory financial protection pool for the remaining $10.5 billion of the approximately $10.8 billion public liability limit for a nuclear incident. Under the terms of the sale, RG&E remains liable for assessments under the mandatory financial protection pool for incidents that may have occurred prior to the sale on June 10, 2004. If an incident can be conclusively determined to have occurred prior to the sale, RG&E could be assessed up to $101 million per incident payable at a rate not to exceed $10 million per incident per year. RG&E is not aware of any incidents that would lead to such an assessment.

In addition to the insurance required by the Price-Anderson Act, RG&E also carried nuclear property damage insurance and accidental outage insurance through Nuclear Electric Insurance Limited (NEIL). Under those insurance policies, RG&E could be subject to retrospective premium adjustments for six years following the end of the policy period if losses exceed the accumulated funds available to the insurers. The maximum amounts of the adjustments for RG&E's final policy year were $13 million for nuclear property damage insurance and $4 million for accidental outage insurance. RG&E is not aware of any events that would initiate a retrospective premium adjustment under the NEIL policies.

NOTE 3 Sale of Other Businesses

In keeping with its focus on regulated electric and natural gas delivery businesses, during recent years the company has been systematically exiting certain noncore businesses. All businesses sold were previously reported in the company's Other business segment. In October 2004 Energy East Solutions, Inc., a subsidiary of The Energy Network, Inc., completed the sale of its New England and Pennsylvania natural gas customer contracts and related assets at an after-tax loss of less than $1 million. In July 2004 Union Water Power Company, a subsidiary of CMP Group, sold the assets associated with its utility locating and construction divisions at an after-tax loss of $7 million. In 2004 the company recognized a loss from discontinued operations of $8 million or 6 cents per share.

In 2003 Berkshire Propane, Inc., a subsidiary of Berkshire Energy, sold its assets and Energetix, Inc., a subsidiary of RGS Energy, sold its subsidiary Griffith Oil Co., Inc. In 2004 the company recorded a change in estimated taxes of $1.2 million related to the sale of Griffith Oil to reflect actual taxes in accordance with the filing of the company's 2003 federal and state income tax returns.

In 2002 Berkshire Service Solutions, Inc., an energy service provider and a subsidiary of Berkshire Energy, was sold.

The results of discontinued operations of the businesses sold were:

Year Ended December 31	2004	2003	2002
(Thousands)			
Component of Energy East Solutions, Inc.			
Revenues	**$48,634**	$57,478	$35,399
(Loss) income from operations of discontinued business (including loss on disposal of $(205) in 2004)	**$(859)**	$68	$(267)
Income taxes (benefits)	**(142)**	27	(149)
(Loss) income from discontinued operations	**$(717)**	$41	$(118)
Certain Divisions of Union Water Power Co.			
Revenues	**$13,156**	$21,851	$23,044
Loss from operations of discontinued business (including loss on disposal of $(7,360) in 2004)	**$(6,249)**	$(2,147)	$(585)
Income taxes (benefits)	**152**	(1,003)	(1,290)
(Loss) income from discontinued operations	**$(6,401)**	$(1,144)	$705
Griffith Oil Co., Inc.			
Revenues	**–**	$321,447	$164,464
(Loss) income from operations of discontinued business	**–**	$(7,798)	$1,786
Income taxes (benefits)	**$1,166**	(13,387)	882
(Loss) income from discontinued operations	**$(1,166)**	$5,589	$904
Berkshire Propane, Inc.			
Revenues	**–**	$5,494	$6,051
(Loss) income from operations of discontinued business	**–**	$(2,155)	$74
Income taxes (benefits)	**–**	375	30
(Loss) income from discontinued operations	**–**	$(2,530)	$44
Berkshire Service Solutions, Inc.			
Revenues	**–**	–	$1,934
Loss from operations of discontinued business	**–**	–	$(4,087)
Income taxes (benefits)	**–**	–	(1,226)
Loss from discontinued operations	**–**	–	$(2,861)
Totals for discontinued operations			
Total revenues	**$61,790**	$406,270	$230,892
Total loss from operations of discontinued businesses	**$(7,108)**	$(12,032)	$(3,079)
Total income taxes (benefits)	**1,176**	(13,988)	(1,753)
Total (loss) income from discontinued operations	**$(8,284)**	$1,956	$(1,326)

The major classes of assets and liabilities at the date of sale of the businesses discontinued in 2004 were:

	Component of Energy East Solutions, Inc.	Certain Divisions of Union Water Power Co.
(Thousands)		
Assets		
Accounts receivable	–	$4,686
Other property and investments, net	$68	$2,567
Goodwill, net	$487	$6,829
Liabilities		
Current liabilities	$61	$1,459

NOTE 4 Restructuring

In the fourth quarter of 2002 Energy East recorded $41 million of restructuring expenses related to its voluntary early retirement and involuntary severance programs at six of its operating companies. The $41 million of restructuring expenses included $5 million for CMP, $26 million for NYSEG and a total of $10 million for Berkshire Gas, CNG and SCG. The restructuring expenses would have been $36 million higher, however RG&E was required by a New York State Public Service Commission order approving RGS Energy's merger with the company to defer its portion of the restructuring charge for future recovery in rates. The employee positions affected by the restructuring were identified in the fourth quarter of 2002. The restructuring expenses reduced the company's 2002 net income by $24 million or 19 cents per share. Included in those amounts were $20 million for the voluntary early retirement program that will be paid from the companies' pension plans and $3 million for the involuntary severance program, primarily for salaried employees, and $1 million for other associated costs. The entire related involuntary severance liability of $9 million was paid during 2003, including $4 million that was deferred for recovery by RG&E.

Energy East has consolidated the accounting and finance functions of five of its operating companies to one location. In connection with this latest restructuring, in 2003 the company recognized a $4 million total liability for an enhanced severance program for 83 accounting and finance employees who were employed through March 31, 2004. During the fourth quarter of 2003, 40% or approximately $2 million, of the estimated liability was charged to other operating expenses and represented the company's cumulative expense and liability as of December 31, 2003. The remaining $2 million of the liability was charged to other operating expenses in the first quarter of 2004. Approximately $3 million of the total cost was incurred by the electric delivery business and $1 million by the natural gas delivery business. The liability was paid as of June 30, 2004.

NOTE 5 Goodwill and Other Intangible Assets

The company does not amortize goodwill or intangible assets with indefinite lives (unamortized intangible assets). The company tests both goodwill and unamortized intangible assets for impairment at least annually. The company amortizes intangible assets with finite lives (amortized intangible assets) and reviews them for impairment. Annual impairment testing was completed and it was determined that there was no impairment of goodwill or unamortized intangible assets for the company at September 30, 2004.

Changes in the carrying amount of goodwill, by operating segment, for the year ended December 31, 2004, are shown in the following table. The decreases in goodwill relate primarily to nonutility businesses sold in 2004.

	Electric Delivery	Natural Gas Delivery	Other	Total
(Thousands)				
Balance, January 1, 2004	$844,531	$677,119	$11,473	$1,533,123
Goodwill related to businesses sold	–	–	(7,316)	(7,316)
Preacquisition income tax adjustments	(40)	(531)	117	(454)
Balance, December 31, 2004	$844,491	$676,588	$4,274	$1,525,353

Other Intangible Assets | The company's unamortized intangible assets had a carrying amount of $10 million at December 31, 2004 and 2003, and primarily consisted of pension assets. The company's amortized intangible assets had a gross carrying amount of $31 million at December 31, 2004 and 2003, and primarily consisted of investments in pipelines and customer lists. Accumulated amortization was $15 million at December 31, 2004, and $12 million at December 31, 2003. Estimated amortization expense for intangible assets for the next five years is approximately $2 million for 2005 and approximately $1 million each year for 2006 through 2009.

NOTE 6 Income Taxes

Year Ended December 31	2004	2003	2002
(Thousands)			
Current			
Federal	$99,267	$19,920	$50,525
State	19,186	392	2,950
Current taxes charged to expense	118,453	20,312	53,475
Deferred			
Federal	123,517	92,945	38,481
State	17,545	19,057	10,845
Deferred taxes charged to expense	141,062	112,002	49,326
ITC adjustments	(8,071)	(3,651)	(2,524)
Total for Continuing Operations	$251,444	$128,663	$100,277

The company's effective tax rate differed from the statutory rate of 35% due to the following:

Year Ended December 31	2004	2003	2002
(Thousands)			
Tax expense at statutory rate	$172,465	$124,656	$112,817
Depreciation and amortization not normalized	2,220	10,715	5,125
ITC amortization	(8,071)	(3,651)	(2,524)
Trust preferred securities	–	(4,978)	(9,932)
ASGA – Ginna	80,075	–	–
State taxes, net of federal benefit	23,875	12,641	8,967
Other, net	(19,120)	(10,720)	(14,176)
Total for Continuing Operations	$251,444	$128,663	$100,277

The effective tax rate for continuing operations was 51% in 2004 and 36% in 2003. The company's effective tax rate for 2004 increased compared to the prior year primarily as a result of the regulatory treatment of the deferred gain from RG&E's sale of Ginna. RG&E recorded pretax income of $112 million and income tax expense of $112 million. (See Note 2.) Other factors contributing to the increase in the effective tax rate were increases in the estimate of prior year taxes of $3 million, primarily the result of the effects of the combined New York State filings for 2002 and 2003. The effective tax rate for continuing operations was 36% in 2003 and 31% in 2002. The increase was primarily due to the recognition as interest expense in 2003 of distributions that the company had previously recognized as preferred stock dividends and the effect of depreciation and amortization not normalized related to RG&E for a full year in 2003 compared to six months in 2002.

At December 31, 2004 and 2003, the company's consolidated deferred tax assets and liabilities consisted of:

	2004	2003
(Thousands)		
Current Deferred Income Tax Assets	**$33,969**	$26,262
Noncurrent Deferred Income Tax Liabilities		
Depreciation	**$869,919**	$821,783
Unfunded future income taxes	**148,116**	144,705
Accumulated deferred ITC	**33,666**	41,494
Deferred (gain) loss on sale of generation assets	**(65,485)**	35,211
Pension benefits	**171,280**	151,559
Statement 106 postretirement benefits	**(121,292)**	(84,327)
Nuclear decommissioning	**-**	(49,681)
Other	**(41,118)**	(26,044)
Total Noncurrent Deferred Income Tax Liabilities	**995,086**	1,034,700
Less amounts classified as regulatory liabilities		
Deferred income taxes	**21,487**	181,211
Noncurrent Deferred Income Tax Liabilities	**$973,599**	$853,489

Energy East and its subsidiaries have no federal tax credit carryforwards. A subsidiary of Energy East has a state loss carryforward of less than $1 million, with no valuation allowance.

NOTE 7 Long-term Debt

Debt owed to subsidiary holding solely parent debentures | The debt owed to subsidiary holding solely parent debentures consists of the company's 8 1/4% junior subordinated debt securities maturing on July 1, 2031, that are held by Energy East Capital Trust I.

Energy East Capital Trust I is a Delaware business trust that is a wholly-owned finance subsidiary of the company. Based on the trust's structure the company is not considered the primary beneficiary of the trust and does not consolidate the trust. The assets of the trust consist of the company's 8 1/4% junior subordinated debt securities. The trust has issued $345 million of mandatorily redeemable trust preferred securities that are 8 1/4% Capital Securities. The company has fully and unconditionally guaranteed the trust's payment obligations with respect to the Capital Securities.

Preferred stock of subsidiary subject to mandatory redemption requirements | On March 1, 2004, RG&E redeemed, at par, as required by a mandatory sinking fund provision, $1.25 million of its 6.60% Series V preferred stock, Par Value $100. On May 5, 2004, RG&E redeemed, at par, the remaining $23.75 million of the 6.60% Series V preferred stock.

Other long-term debt | At December 31, 2004 and 2003, the company's consolidated other long-term debt was:

	Maturity Dates	Interest Rates	2004	2003
(Thousands)				
First mortgage bonds[1]	2005 to 2033	5.84% to 10.06%	**$785,500**	$914,500
Pollution control notes, fixed	2006 to 2033	4.00% to 6.15%	**219,000**	351,000
Pollution control notes, variable	2015 to 2034	1.08% to 2.05%	**555,800**	408,900
Various long-term debt	2005 to 2033	4.25% to 10.48%	**1,942,946**	1,994,355
Obligations under capital leases			**29,268**	31,821
Unamortized premium and discount on debt, net			**(31,268)**	(31,161)
			3,501,246	3,669,415
Less debt due within one year, included in current liabilities			**59,231**	30,989
Total			**$3,442,015**	$3,638,426

(1) For Energy East, on a consolidated basis. In addition to the information provided below for RG&E, Berkshire Gas and SCG have first mortgage bonds that are secured by liens on substantially all of their respective utility properties.

As a registered holding company under the Public Utility Holding Company Act of 1935, Energy East is prohibited from obtaining guarantees and credit support from its subsidiaries. Energy East has no secured indebtedness and none of its assets are mortgaged, pledged or otherwise subject to lien. None of Energy East's debt obligations are guaranteed or secured by its subsidiaries.

CMP has no long-term debt obligations that are secured. CMP has no intercompany collateralizations and has no guarantees to affiliates or subsidiaries. CMP's debt has no guarantees from parent or affiliates or any additional credit support.

NYSEG has no secured indebtedness. None of NYSEG's debt obligations are guaranteed or secured by any of its affiliates.

RG&E's first mortgage bonds, totaling $572 million at December 31, 2004, are secured by a first mortgage lien on substantially all of its properties. RG&E has no other secured indebtedness. None of RG&E's other debt obligations are guaranteed or secured by any of its affiliates.

At December 31, 2004, other long-term debt, including sinking fund obligations, and capital lease payments (in thousands) that will become due during the next five years are:

2005	2006	2007	2008	2009
$59,231	$323,509	$232,240	$96,330	$148,929

Cross-default Provisions | Energy East has a provision in its senior unsecured indenture, which provides that default by the company with respect to any other debt in excess of $40 million will be considered a default under the company's senior unsecured indenture. Energy East also has a provision in its revolving credit agreements, which provides that default by the company with respect to any other debt in excess of $50 million will be considered a default under the company's revolving credit agreements.

NYSEG has provisions in its unsecured indenture relating to certain series of pollution control bonds, which provide that default by NYSEG with respect to any other debt in excess of $40 million will be considered a default under those respective documents.

RG&E has a provision in a participation agreement relating to certain series of pollution control bonds, which provides that default by RG&E with respect to bonds issued under its first mortgage indenture will be considered a default under the participation agreement.

NOTE 8 Bank Loans and Other Borrowings

The company and its subsidiaries have revolving credit agreements with various expiration dates in 2005 and 2009 and pay fees in lieu of compensating balances in connection with those agreements. The agreements provided for maximum borrowings of $740 million at December 31, 2004, and $700 million at December 31, 2003.

The company and its subsidiaries use short-term, unsecured notes and drawings on their credit agreements to finance working capital needs and for other corporate purposes. There was $206 million of such short-term debt outstanding at December 31, 2004, and $308 million outstanding at December 31, 2003. The weighted-average interest rate on short-term debt was 2.8% at December 31, 2004, and 1.8% at December 31, 2003.

In its revolving credit agreements Energy East covenants not to permit, without the consent of the lenders, its ratio of consolidated indebtedness to consolidated total capitalization at any time to exceed 0.65 to 1.00. Continued unremedied failure to comply with this covenant for 15 days after written notice of such failure from any lender constitutes an event of default and would result in acceleration of maturity. Energy East's ratio of consolidated indebtedness to consolidated total capitalization pursuant to the revolving credit agreements was 0.58 to 1.00 at December 31, 2004.

In its revolving credit facility, secured by its accounts receivable, CMP covenants that (i) its consolidated total debt shall at all times be no more than 65% of the sum of its consolidated total debt and its total stockholder's equity, and (ii) as of the end of any fiscal quarter CMP's ratio of earnings before interest expense, income taxes and preferred stock dividends to interest expense for the prior four fiscal quarters shall have been at least 1.75 to 1.00. Continued unremedied failure to comply with either covenant for 30 days after such event has occurred constitutes an event of default and would result in acceleration of maturity. At December 31, 2004, CMP's consolidated total debt ratio was 31% and its interest coverage ratio was 3.9 to 1.00.

In their joint revolving credit agreement NYSEG and RG&E each covenant not to permit, without the consent of the lenders, (i) their respective ratio of earnings before interest expense and income tax to interest expense to be less than 1.5 to 1.0 at any time, and (ii) their respective ratio of total indebtedness to total capitalization to exceed 0.65 to 1.00 at any time. Continued unremedied failure to observe these covenants for five business days after written notice of such failure from any lender constitutes an event of default and would result in acceleration of maturity for the party in default. At December 31, 2004, the ratio of earnings before interest expense and income tax to interest expense was 5.4 to 1.0 for NYSEG and 5.6 to 1.0 for RG&E. At December 31, 2004, the ratio of total indebtedness to total capitalization was 0.54 to 1.00 for NYSEG and 0.55 to 1.00 for RG&E.

NOTE 9 Preferred Stock Redeemable Solely at the Option of Subsidiaries

At December 31, 2004 and 2003, the company's consolidated preferred stock was:

Subsidiary and Series	Par Value Per Share	Redemption Price Per Share	Shares Authorized and Outstanding[1]	Amount (Thousands) 2004	2003
CMP, 6% Noncallable	$100	–	5,180	**$518**	$518
CMP, 3.50%	100	$101.00	220,000	**22,000**	22,000
CMP, 4.60%	100	101.00	30,000	**3,000**	3,000
CMP, 4.75%	100	101.00	50,000	**5,000**	5,000
CMP, 5.25%	100	102.00	50,000	**5,000**	5,000
NYSEG, 3.75%	100	104.00	78,379	**7,838**	7,838
NYSEG, 4 1/2% (1949)	100	103.75	11,800	**1,180**	1,180
NYSEG, 4.40%	100	102.00	7,093	**709**	709
NYSEG, 4.15% (1954)	100	102.00	4,317	**432**	432
RG&E, 4% F	100	–	–	**–**	12,000
RG&E, 4.10% H	100	–	–	**–**	8,000
RG&E, 4.75% I	100	–	–	**–**	6,000
RG&E, 4.10% J	100	–	–	**–**	5,000
RG&E, 4.95% K	100	–	–	**–**	6,000
RG&E, 4.55% M	100	–	–	**–**	10,000
Berkshire Gas, 4.80%	100	100.00	2,443	**244**	250
CNG, 6.00%	100	110.00	4,104	**411**	411
CNG, 8.00% Noncallable	3.125	–	108,706	**339**	339
Total				**$46,671**	$93,677

(1) At December 31, 2004, the company and its subsidiaries had 16,510,957 shares of $100 par value preferred stock, 16,800,000 shares of $25 par value preferred stock, 775,609 shares of $3.125 par value preferred stock, 600,000 shares of $1 par value preferred stock, 10,000,000 shares of $.01 par value preferred stock, 1,000,000 shares of $100 par value preference stock and 6,000,000 shares of $1 par value preference stock authorized but unissued.

The company's subsidiaries redeemed or purchased the following amounts of preferred stock during the three years 2002 through 2004:

Subsidiary	Date	Series	Amount (Thousands)
CNG	June 7, 2002	6.00%	$2.5 *
CNG	September 16, 2003	8.00%	$0.4 *
Berkshire Gas	September 30, 2002	4.80%	$1.5 *
Berkshire Gas	September 9, 2003	4.80%	$7.5 *
Berkshire Gas	September 16, 2004	4.80%	$5.6 *
RG&E	May 5, 2004	4% F	$12,000 **
RG&E	May 5, 2004	4.10% H	$8,000 **
RG&E	May 5, 2004	4.75% I	$6,000 **
RG&E	May 5, 2004	4.10% J	$5,000 **
RG&E	May 5, 2004	4.95% K	$6,000 **
RG&E	May 5, 2004	4.55% M	$10,000 **

*Redeemed **Purchased at a premium

Voting rights | If preferred stock dividends on any series of preferred stock of a subsidiary, other than the CMP 6% Noncallable series and the CNG 8.00% series, are in default in an amount equivalent to four full quarterly dividends, the holders of the preferred stock of such subsidiary are entitled to elect a majority of the directors of such subsidiary (and, in the case of the CNG 6.00% series, the largest number of directors constituting a minority of the board) and their privilege continues until all dividends in default have been paid. The holders of preferred stock, other than the CMP 6% Noncallable series and the CNG 8.00% series, are not entitled to vote in respect of any other matters except those, if any, in respect of which voting rights cannot be denied or waived under some mandatory provision of law, and except that the charters of the respective subsidiaries contain provisions to the effect that such holders shall be entitled to vote on certain matters affecting the rights and preferences of the preferred stock.

Holders of the CMP 6% Noncallable series and the CNG 8.00% series are entitled to one vote per share and have full voting rights on all matters.

Whenever holders of preferred stock shall be entitled to vote, they shall be entitled to cast one vote for each share of preferred stock held by them. Holders of NYSEG common stock are entitled to one vote per share on all matters, except in the election of directors with respect to which NYSEG common stock has cumulative voting rights. Holders of CMP common stock are entitled to one-tenth of one vote per share on all matters. Holders of the common stock of the other subsidiaries are entitled to one vote per share on all matters.

NOTE 10 Commitments and Contingencies

Capital spending | The company has commitments in connection with its capital spending program. Capital spending is projected to be $388 million in 2005 and is expected to be paid for principally with internally generated funds. The program is subject to periodic review and revision. The company's capital spending will be primarily for the extension of energy delivery service, necessary improvements to existing facilities, compliance with environmental requirements and governmental mandates, merger integration, a customer care system, and an Infrastructure Replacement Program.

Nonutility generator power purchase contracts | CMP and NYSEG together expensed approximately $613 million for NUG power in 2004, $608 million in 2003 and $611 million in 2002. CMP and NYSEG estimate that their combined NUG power purchases will be $674 million in 2005, $615 million in 2006, $563 million in 2007, $381 million in 2008 and $229 million in 2009.

NYISO billing adjustment | The NYISO frequently bills transmission owners on a retroactive basis when adjustments are necessary. Such retroactive billings can cover several months or years and cannot be reasonably estimated. NYSEG and RG&E record transmission revenue or expense as appropriate when revised amounts can be estimated. On January 25, 2005, the NYISO notified New York transmission owners, including NYSEG and RG&E, of a revenue allocation formula error related to transmission congestion contracts for periods including May 2000 through October 2002. The NYISO has not yet provided any further details. The correction of the error may result in revised billings for NYSEG and RG&E. The companies cannot predict at this time either the magnitude or the direction of any billing adjustments.

NOTE 11 Jointly-Owned Generation Assets and Nuclear Decommissioning

CMP | CMP has ownership interests in three nuclear generating facilities in New England, which are accounted for under the equity method. All three facilities have been permanently shut down, and are in the process of being decommissioned.

	Maine Yankee	Yankee Atomic	Connecticut Yankee
($ in Millions)			
Ownership share	38%	9.5%	6%
Location	Wiscasset, Maine	Rowe, Massachusetts	Haddam, Connecticut
2004 decommissioning and other costs	$23.6	$5.2	$2.6
Share of remaining decommissioning and other costs (in 2004 dollars)	$102.9	$10.2	$33.2
Expected decommissioning year of completion	2005	2005	2006
Equity interest at December 31, 2004	$13.2	–	$2.6

Operating expenses | CMP is obligated to pay its proportionate share of the expenses, including decommissioning, depreciation, spent fuel storage, operation and maintenance expenses, and a return on invested capital, for each of the Yankee companies referred to above. These amounts are recorded as other liabilities along with a corresponding regulatory asset. Maine's Electric Industry Restructuring Act requires the Maine Public Utilities Commission to provide a reasonable opportunity to recover stranded costs through electric distribution rates. Nuclear-related costs are stranded costs and are included in CMP's stranded costs for purposes of rate recovery. Any increase in costs not currently included in rates is deferred for future recovery.

Cayuga Energy, Inc. | Cayuga Energy, Inc. owns an 85% interest in South Glens Falls Energy, LLC, the owner of a 67-megawatt natural gas-fired combined cycle generating station operating as an exempt wholesale generator.

As part of a joint venture with PEI Power Corporation, Cayuga Energy, Inc. owns 50.1% of a 44-megawatt natural gas-fired peaking-power plant. The joint venture company, PEI Power II, LLC, operates the plant as an exempt wholesale generator.

NOTE 12 Environmental Liability

From time to time environmental laws, regulations and compliance programs may require changes in the company's operations and facilities and may increase the cost of electric and natural gas service.

The United States Environmental Protection Agency and various state environmental agencies, as appropriate, notified the company that it is among the potentially responsible parties who may be liable for costs incurred to remediate certain hazardous substances at 20 waste sites. The 20 sites do not include sites where gas was manufactured in the past, which are discussed below. With respect to the 20 sites, 10 sites are included in the New York State Registry of Inactive Hazardous Waste Disposal Sites, four are included in Maine's Uncontrolled Sites Program, one is included on the Massachusetts Non-Priority Confirmed Disposal Site list and seven sites are also included on the National Priorities list.

Any liability may be joint and several for certain of those sites. The company has recorded an estimated liability of $2 million related to 11 of the 20 sites. Remediation costs have been paid at the remaining nine sites, and the company expects no additional liability to be incurred. An estimated liability of $3 million has been recorded related to another 11 sites where the company believes it is probable that it will incur remediation costs and/or monitoring costs, although it has not been notified that it is among the potentially responsible parties. The ultimate cost to remediate the sites may be significantly more than the accrued amount. Factors affecting the estimated remediation amount include the remedial action plan selected, the extent of site contamination and the portion attributed to the company.

The company has a program to investigate and perform necessary remediation at its 60 sites where gas was manufactured in the past. Eight sites are included in the New York State Registry, eight sites are included in the New York Voluntary Cleanup Program, five sites are part of Maine's Voluntary Response Action Program and four of those five sites are part of Maine's Uncontrolled Sites Program, three sites are included in the Connecticut Inventory of Hazardous Waste Sites, and three sites are on the Massachusetts Department of Environmental Protection's list of confirmed disposal sites. The company has entered into consent orders with various environmental agencies to investigate and, where necessary, remediate 39 of its 60 sites.

The company's estimate for all costs related to investigation and remediation of its 60 sites ranges from $140 million to $277 million at December 31, 2004. The estimate could change materially based on facts and circumstances derived from site investigations, changes in required remedial action, changes in technology relating to remedial alternatives and changes to current laws and regulations.

The liability to investigate and perform remediation, as necessary, at the known inactive gas manufacturing sites was $140 million at December 31, 2004, and $138 million at December 31, 2003. The company recorded a corresponding regulatory asset, net of insurance recoveries, since it expects to recover the net costs in rates.

Energy East's environmental liabilities are recorded on an undiscounted basis unless payments are fixed and determinable. Nearly all of Energy East's environmental liability accruals, which are expected to be paid through the year 2017, have been established on an undiscounted basis. Insurance settlements have been received by Energy East subsidiaries during the last three years, which they accounted for as reductions in their related regulatory assets.

NOTE 13 Fair Value of Financial Instruments

The carrying amounts and estimated fair values of the company's financial instruments are shown in the following table. The fair values are based on the quoted market prices for the same or similar issues of the same remaining maturities.

December 31	**2004**		2003	
	Carrying Amount	*Estimated Fair Value*	*Carrying Amount*	*Estimated Fair Value*
(Thousands)				
Investments – classified as available-for-sale	**$66,602**	**$66,597**	$342,267	$342,217
Debt owed to affiliate	**$355,670**	**$379,571**	$355,670	$389,814
Preferred stock of subsidiary subject to mandatory redemption requirements	**-**	**-**	$25,000	$25,000
First mortgage bonds	**$784,065**	**$896,747**	$913,111	$1,014,697
Pollution control notes, fixed	**$219,000**	**$229,280**	$351,000	$367,385
Pollution control notes, variable	**$555,800**	**$555,800**	$408,900	$408,900
Various long-term debt	**$1,913,113**	**$2,110,980**	$1,964,583	$2,166,443

The carrying amounts for cash and cash equivalents, notes payable and interest accrued approximate their estimated fair values. A majority of the investments classified as held for sale in 2003 represented decommissioning trust funds for Ginna. In June 2004 those funds were transferred to CGG or made available to RG&E for general corporate purposes. (See Note 2.)

NOTE 14 Stock-Based Compensation

The company has a stock option plan under which it may grant stock options and SARs in relation to its common stock to senior management and certain other key employees. The company's policy is to grant SARs in tandem with any stock options granted. Employees may choose to exercise either the SARs, which are settled in cash, or the stock options. The exercise of SARs or options results in a corresponding cancellation of options or SARs to the extent of the number of shares of company common stock as to which the SARs or options are exercised. The stock options/SARs granted in 2004, 2003 and 2002 vest over either one-year or two-year periods, subject to, with certain exceptions, continuous employment. All stock options/SARs expire 10 years after the grant date. Unoptioned shares totaled 6.6 million of the 13 million shares authorized at December 31, 2004, and 5.5 million of the 13 million shares authorized at December 31, 2003. The company recorded compensation expense for stock options/SARs of $18 million in 2004, $3 million in 2003 and $12 million in 2002.

The following table provides a summary of changes in the number of the company's stock options/SARs outstanding, and other information, as of and for the years ended December 31, 2004, 2003 and 2002. The exercise price of stock options/SARs equals the market price of the company's common stock on the last trading date prior to the date of grant.

	2004		2003		2002	
	Stock Options/ SARs	**Weighted-Average Exercise Price**	**Stock Options/ SARs**	**Weighted-Average Exercise Price**	**Stock Options/ SARs**	**Weighted-Average Exercise Price**
Outstanding at beginning of year	**6,014,522**	**$20.87**	7,024,347	$20.95	4,636,047	$20.95
Options/SARs granted	**1,309,500**	**$24.76**	639,500	$19.10	2,810,500	$20.34
Options exercised	**(8,000)**	**$19.43**	(3,000)	$18.55	–	–
SARs exercised	**(2,802,838)**	**$19.59**	(882,970)	$18.67	(347,863)	$16.26
Options/SARs forfeited	**(156,502)**	**$24.84**	(763,355)	$22.67	(74,337)	$19.43
Outstanding at end of year	**4,356,682**	**$22.72**	6,014,522	$20.87	7,024,347	$20.95
Exercisable at end of year	**3,130,736**	**$22.47**	4,686,352	$21.11	4,702,518	$21.45
Weighted-average fair value per share of options/SARs granted		**$2.93**		$3.01		$3.91

The following table provides certain information about the stock options/SARs outstanding at December 31, 2004:

	Options/SARs Outstanding			**Options/SARs Exercisable**	
Range of Exercise Prices	**Shares**	**Weighted-Average Remaining Contractual Life**	**Weighted-Average Exercise Price**	**Shares**	**Weighted-Average Exercise Price**
		(years)			
$10.88 – $14.69	2,309	2.4	$11.06	2,309	$11.06
$17.94 – $28.72	4,354,373	7.1	$22.73	3,128,427	$22.47
Total	4,356,682	7.1	$22.72	3,130,736	$22.47

The company has a Restricted Stock Plan for its common stock under which an aggregate two million shares may be granted, subject to adjustment. Shares of restricted (or nonvested) stock are awarded to selected employees and are issued in the name of the employee, who has all the rights of a shareholder, subject to certain restrictions on transferability and a risk of forfeiture. The Compensation and Management Succession Committee of the Board of Directors administers the Restricted Stock Plan. However, Energy East's Chairman has the authority to make awards to any employees who are not executive officers, subject to a fixed maximum amount for any one participant. The shares vest based on the conditions outlined in the restricted stock award grants, including the achievement of targeted shareholder returns. Shares of common stock awarded pursuant to the Restricted Stock Plan in 2004 and 2003 were issued out of the company's treasury stock. The shares awarded in 2004 vest no later than January 1, 2010, and the shares awarded in 2003 vest no later than January 1, 2009. The company recorded deferred compensation of $6 million in 2004 and $4 million in 2003, based on the market price of its common stock on the date of the restricted stock award. The company amortizes deferred compensation to compensation expense over the vesting period and reduces compensation expense for any restricted stock cancelled or forfeited in the period the event occurs. Compensation expense related to the Restricted Stock Plan was approximately $4 million in 2004 and $2 million in 2003.

The following table provides a summary of information concerning shares of restricted stock as of and for the years ended December 31, 2004 and 2003.

	2004	2003
Outstanding at beginning of year	**213,930**	–
Awarded	**242,038**	229,230
Released to participants	**(33,700)**	(15,300)
Cancelled	**(4,100)**	–
Outstanding at end of year	**418,168**	213,930
Weighted-average fair value per share of restricted stock awarded	**$23.90**	$19.20

NOTE 15 Accumulated Other Comprehensive Income

(Thousands)	Balance January 1 2002	2002 Change	Balance December 31 2002	2003 Change	Balance December 31 2003	2004 Change	Balance December 31 2004
Unrealized gains (losses) on investments:							
Unrealized holding gains (losses) during period, net of income tax benefit (expense) of $6,803 for 2002, $(253) for 2003 and $316 for 2004		$(9,654)		$744		$142	
Reclassification adjustment for losses included in net income, net of income tax benefit of $5,087 for 2002		7,122		–		–	
Net unrealized gains (losses) on investments	$1,241	(2,532)	$(1,291)	744	$(547)	142	$(405)
Minimum pension liability adjustment, net of income tax benefit (expense) of $39,378 for 2002, $(14,484) for 2003 and $8,378 for 2004	(3,176)	(58,485)	(61,661)	21,192	(40,469)	(7,566)	(48,035)
Unrealized gains (losses) on derivatives qualified as hedges:							
Unrealized gains (losses) during period on derivatives qualified as hedges, net of income tax benefit (expense) of $(26,984) for 2002, $(14,391) for 2003, and $(5,061) for 2004		37,692		22,320		8,964	
Reclassification adjustment for (gains) losses included in net income, net of income tax (benefit) expense of $(7,351) for 2002, $14,123 for 2003 and $22,037 for 2004		11,493		(21,303)		(33,887)	
Net unrealized gains (losses) on derivatives qualified as hedges	(20,400)	49,185	28,785	1,017	29,802	(24,923)	4,879
Accumulated Other Comprehensive Income (Loss)	$(22,335)	$(11,832)	$(34,167)	$22,953	$(11,214)	$(32,347)	$(43,561)

(See Risk management in Note 1.)

NOTE 16 Retirement Benefits

Energy East sponsors defined benefit pension plans and postretirement benefit plans applicable to substantially all employees. The company uses a December 31 measurement date for its pension and postretirement benefit plans.

	Pension Benefits		Postretirement Benefits	
	2004	2003	**2004**	2003
(Thousands)				
Change in benefit obligation				
Benefit obligation at January 1	**$2,140,119**	$2,093,864	**$611,236**	$557,270
Service cost	**32,069**	31,216	**6,082**	6,686
Interest cost	**130,891**	132,491	**34,672**	36,712
Plan participants' contributions	**–**	–	**–**	303
Plan amendments	**6,536**	9	**(13,361)**	(785)
Actuarial loss (gain)	**145,100**	62,881	**(37,532)**	44,371
Divestitures	**(54,444)**	–	**(6,071)**	–
Curtailment	**–**	(655)	**–**	–
Benefits paid	**(146,062)**	(179,687)	**(35,049)**	(33,321)
Benefit obligation at December 31	**$2,254,209**	$2,140,119	**$559,977**	$611,236
Change in plan assets				
Fair value of plan assets at January 1	**$2,392,066**	$2,064,401	**$37,019**	$34,088
Actual return on plan assets	**260,652**	487,346	**3,047**	5,905
Employer contributions	**19,661**	20,006	**26,617**	30,044
Divestitures	**(50,823)**	–	**–**	–
Plan participants' contributions	**–**	–	**–**	303
Benefits paid	**(146,062)**	(179,687)	**(34,578)**	(33,321)
Fair value of plan assets at December 31	**$2,475,494**	$2,392,066	**$32,105**	$37,019
Funded status	**$221,285**	$251,947	**$(527,872)**	$(574,217)
Unrecognized net actuarial loss	**388,724**	312,856	**97,932**	140,940
Unrecognized prior service cost (benefit)	**47,393**	45,360	**(44,372)**	(48,221)
Unrecognized net transition (asset) obligation	**–**	(1,230)	**54,427**	72,595
Prepaid (accrued) benefit cost	**$657,402**	$608,933	**$(419,885)**	$(408,903)
Amounts recognized on the balance sheet				
Prepaid benefit cost	**$657,402**	$608,933	**–**	–
Accrued benefit cost	**–**	–	**$(419,885)**	$(408,903)
Additional minimum liability	**(166,418)**	(149,101)	**–**	–
Intangible asset	**7,016**	5,847	**–**	–
Regulatory liability	**76,914**	76,914	**–**	–
Accumulated other comprehensive income	**82,488**	66,340	**–**	–
Net amount recognized	**$657,402**	$608,933	**$(419,885)**	$(408,903)

The company's accumulated benefit obligation for all defined benefit pension plans was $2.0 billion at December 31, 2004 and $1.9 billion at December 31, 2003. The sale of Ginna resulted in a decrease in the projected benefit obligation of $54 million, and $51 million of pension funds were transferred as part of the sale.

CMP Group's, CNE's and CTG Resources' postretirement benefits were partially funded as of December 31, 2004 and 2003.

The minimum liability included in other comprehensive income for pension benefits increased $16 million in 2004 and decreased $36 million in 2003. The company recorded a minimum pension liability of $166 million at December 31, 2004, as required by Statement of Financial Accounting Standards No. 87, Employers' Accounting for Pensions. The effect of the minimum pension liability was recognized in other long-term liabilities, intangible assets, regulatory liability and other comprehensive income, as appropriate, and is prescribed when the accumulated benefit obligation in the plan exceeds the fair value of the underlying pension plan assets and accrued pension liabilities. The increase in the unfunded accumulated benefit obligation in 2004 was primarily due to a decrease in the assumed discount rate.

Weighted-average assumptions used to determine benefit obligations at December 31	**Pension Benefits**		**Postretirement Benefits**	
	2004	2003	**2004**	2003
Discount rate	**5.75%**	6.25%	**5.75%**	6.25%
Rate of compensation increase	**4.00%**	4.00%	**4.00%**	4.00%

As of December 31, 2004, the company decreased its discount rate from 6.25% to 5.75%.

	Pension Benefits			**Postretirement Benefits**		
	2004	2003	2002	**2004**	2003	2002
(Thousands)						
Components of net periodic benefit cost						
Service cost	**$32,069**	$31,216	$29,318	**$6,082**	$6,686	$6,040
Interest cost	**130,891**	132,491	111,943	**34,672**	36,712	32,215
Expected return on plan assets	**(206,120)**	(204,173)	(190,541)	**(2,480)**	(2,801)	(2,993)
Amortization of prior service cost	**4,650**	4,985	8,035	**(7,273)**	(6,879)	(6,761)
Recognized net actuarial gain	**(1,106)**	(6,185)	(36,686)	**4,968**	6,729	1,647
Amortization of transition (asset) obligation	**(1,230)**	(7,238)	(7,238)	**8,001**	8,066	9,126
Special termination benefits	**–**	–	64,909	**–**	–	–
Curtailment	**(148)**	403	–	**230**	(614)	–
Settlement charge	**12,186**	–	–	**(6,131)**	–	–
Deferral for future recovery	**–**	–	(32,086)	**–**	–	–
Net periodic benefit cost	**$(28,808)**	$(48,501)	$(52,346)	**$38,069**	$47,899	$39,274

Net periodic benefit cost is included in other operating expenses. The net periodic benefit cost for postretirement benefits represents the cost the company charged to expense for providing health care benefits to retirees and their eligible dependents. The amount of postretirement benefit cost deferred was $67 million as of December 31, 2004, and $80 million as of December 31, 2003. The company expects to recover any deferred postretirement costs by 2012. The transition obligation for postretirement benefits that resulted from the adoption of Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, is being amortized over 20 years.

Weighted-average assumptions used to determine net periodic benefit cost Year ended December 31	**Pension Benefits**			**Postretirement Benefits**		
	2004	2003	2002	**2004**	2003	2002
Discount rate	**6.25%**	6.50%	7.00%	**6.25%**	6.50%	7.00%
Expected return on plan assets	**8.75%**	8.75%	9.00%	**8.75%**	8.75%	9.00%
Rate of compensation increase	**4.00%**	4.00%	4.00%	**4.00%**	4.00%	4.00%

The company's expected rate of return on plan assets assumption was developed based on a review of historical returns for the major asset classes. That analysis also considered both current capital market conditions and projected future conditions. Given the current low interest rate environment, the company selected an assumption of 8.75% per year, which is lower than the rate that would otherwise be determined solely based on historical returns.

The company assumed a 10.0% annual rate of increase in the per capita cost of covered health care benefits for 2005 that gradually decreases to 5.0% by the year 2008. Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
(Thousands)		
Effect on total of service and interest cost components	$2,115	$(1,809)
Effect on postretirement benefit obligation	$32,786	$(27,917)

In December 2003 President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) into law. The Medicare Act introduces a federal subsidy (the subsidy) to sponsors of single-employer defined benefit postretirement health care plans that provide to some or all participants prescription drug benefits that are at least actuarially equivalent to Medicare Part D.

In May 2004 the FASB issued its FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (FSP No. FAS 106-2), which provides guidance on accounting for the effects of the Medicare Act and requires certain disclosures regarding the effect of the subsidy. The company adopted FSP No. FAS 106-2 prospectively in the third quarter of 2004 and remeasured its plan assets and accumulated postretirement benefit obligation (APBO) as of July 1, 2004, including the effects of the Medicare Act and the subsidy. Based on information available as of the date of adoption of FSP No. FAS 106-2, the company concluded that the prescription drug benefits provided by nearly all of its postretirement health care plans are actuarially equivalent to Medicare Part D benefits to be provided under the Medicare Act. RG&E concluded that the effects of the Medicare Act and the subsidy are insignificant because of employer caps and limited employee participation in RG&E's plans that provide postretirement prescription drug benefits.

As of July 1, 2004, the reduction in the company's APBO for the subsidy related to benefits attributed to past service was $44 million. The subsidy reduced the company's measurement of its net periodic postretirement benefit cost by $3.3 million for the six months ended December 31, 2004, including the following amounts that were reduced: service cost $0.1 million, interest cost $1.4 million and amortization of unrecognized net actuarial gain $1.8 million.

The company's weighted-average asset allocations at December 31, 2004 and 2003, by asset category are:

	Pension Benefits			Postretirement Benefits		
Asset Category	Target Allocation	2004	2003	Target Allocation	2004	2003
Equity securities	60%	**62%**	64%	50%	**54%**	53%
Debt securities	30%	**32%**	34%	45%	**40%**	45%
Real estate	5%	**–**	–	–	**–**	–
Other	5%	**6%**	2%	5%	**6%**	2%
Total	100%	**100%**	100%	100%	**100%**	100%

The company's pension plan assets are held in a master trust with a trustee and are invested among and within various asset classes in order to achieve sufficient diversification in accordance with the company's risk tolerance. This is achieved through the utilization of multiple asset managers and systematic allocation to investment management styles, providing a broad exposure to different segments of the fixed income and equity markets.

The company's postretirement benefits plan assets are held with various trustees in multiple voluntary employees' beneficiary association and 401(h) arrangements and are invested among and within various asset classes in order to achieve sufficient diversification in accordance with the company's risk tolerance. This is achieved through the utilization of multiple institutional mutual and money market funds, which provide exposure to different segments of the fixed income, equity and short-term cash markets.

Equity securities did not include any Energy East common stock as of December 31, 2004 and 2003.

As of December 31, 2004 and 2003, the accumulated benefit obligation and the projected benefit obligation exceeded the fair value of pension plan assets for CMP's, CNG's and SCG's plans. The following table shows the aggregate projected and accumulated benefit obligations and the fair value of plan assets for those three companies' plans.

December 31	Benefit Obligation Exceeds Fair Value of Plan Assets 2004	2003
(Thousands)		
Projected benefit obligation	**$529,433**	$478,899
Accumulated benefit obligation	**$474,250**	$430,754
Fair value of plan assets	**$397,714**	$365,431

The company expects to contribute approximately $54 million to its pension plans and approximately $10 million to its other postretirement benefit plans in 2005.

Expected benefit payments and expected Medicare Act subsidy receipts, which reflect expected future service, as appropriate, are as follows:

	Pension Benefits	Postretirement Benefits	Medicare Act Subsidy Receipts
(Thousands)			
2005	$126,050	$47,649	–
2006	$128,336	$50,992	$2,982
2007	$130,868	$53,734	$3,299
2008	$135,185	$56,201	$3,650
2009	$141,219	$58,212	$3,892
2010–2014	$830,090	$334,731	$22,189

NOTE 17 Segment Information

Selected financial information for the company's operating segments is presented in the table below. The company's electric delivery segment consists of its regulated transmission, distribution and generation operations in New York and Maine and its natural gas delivery segment consists of its regulated transportation, storage and distribution operations in New York, Connecticut, Maine and Massachusetts. The company measures segment profitability based on net income. Other includes: the company's corporate assets, interest income, interest expense and operating expenses; intersegment eliminations; and nonutility businesses.

	Electric Delivery	Natural Gas Delivery	Other	Total
(Thousands)				
2004				
Operating Revenues	**$2,781,322**	**$1,549,150**	**$426,220**	**$4,756,692**
Depreciation and Amortization	**$196,782**	**$88,998**	**$6,678**	**$292,458**
Interest Charges, Net	**$205,501**	**$82,579**	**$(11,190)**	**$276,890**
Income Taxes	**$199,595**	**$36,278**	**$15,571**	**$251,444**
Net Income	**$165,199**	**$61,211**	**$2,927**	**$229,337**
Total Assets	**$6,737,573**	**$3,851,063**	**$207,477**	**$10,796,113**
Capital Spending	**$185,544**	**$107,735**	**$5,984**	**$299,263**
2003				
Operating Revenues	$2,758,695	$1,462,127	$293,668	$4,514,490
Depreciation and Amortization	$211,120	$81,433	$6,879	$299,432
Interest Charges, Net	$201,684	$76,113	$6,993	$284,790
Income Taxes	$89,337	$50,096	$(10,770)	$128,663
Net Income (Loss)	$152,720	$70,837	$(13,111)	$210,446
Total Assets	$7,309,267	$3,544,162	$477,012	$11,330,441
Capital Spending	$192,409	$99,746	$10,357	$302,512
2002				
Operating Revenues	$2,568,247	$1,032,539	$177,240	$3,778,026
Depreciation and Amortization	$162,515	$71,329	$6,462	$240,306
Interest Charges, Net	$183,716	$73,177	$(732)	$256,161
Income Taxes	$94,238	$26,557	$(20,518)	$100,277
Net Income (Loss)	$170,337	$51,128	$(32,862)	$188,603
Total Assets	$7,032,043	$3,428,956	$483,348	$10,944,347
Capital Spending	$137,414	$86,301	$5,672	$229,387

NOTE 18 Quarterly Financial Information (Unaudited)

Quarter Ended	**March 31**	**June 30**	**September 30**	**December 31**
(Thousands, except per share amounts)				
2004				
Operating Revenues	**$1,551,356**	**$968,938**	**$967,805**	**$1,268,593**
Operating Income	**$267,692**	**$233,873**	**$91,422**	**$156,966**
Income from Continuing Operations	**$120,929**	**$42,823**	**$17,500**	**$56,369**
Net Income	**$120,552**	**$38,066**	**$15,973**	**$54,746**
Earnings Per Share, basic	**$.82**	**$.26**	**$.11**	**$.38**
Earnings Per Share, diluted	**$.82**	**$.26**	**$.11**	**$.37**
Dividends Per Share	**$.26**	**$.26**	**$.26**	**$.275**
Average Common Shares Outstanding, basic	**146,085**	**146,148**	**146,385**	**146,597**
Average Common Shares Outstanding, diluted	**146,428**	**146,596**	**146,807**	**147,015**
Common Stock Price				
High	**$25.49**	**$26.05**	**$25.25**	**$27.08**
Low	**$22.29**	**$21.85**	**$23.48**	**$24.75**
2003				
Operating Revenues	$1,483,844	$968,906	$890,276	$1,171,464
Operating Income	$294,079	$123,949	$72,270	$161,514
Income from Continuing Operations	$131,770	$28,082	$2,146	$46,492
Net Income (Loss)	$135,464	$27,717	$(5,979)	$53,244
Earnings (Loss) Per Share, basic	$.93	$.19	$(.04)	$.37
Earnings (Loss) Per Share, diluted	$.93	$.19	$(.04)	$.36
Dividends Per Share	$.25	$.25	$.25	$.25
Average Common Shares Outstanding, basic	145,096	145,415	145,684	145,936
Average Common Shares Outstanding, diluted	145,215	145,640	145,901	146,150
Common Stock Price				
High	$23.71	$21.95	$22.48	$23.71
Low	$17.40	$17.70	$19.39	$21.64

Report of Independent Registered Public Accounting Firm

PRICEWATERHOUSECOOPERS

To the Shareholders and Board of Directors
of Energy East Corporation

We have completed an integrated audit of Energy East Corporation's 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of cash flows and of changes in common stock equity present fairly, in all material respects, the financial position of Energy East Corporation and its subsidiaries ("the Company") at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, and effective July 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. In addition, as discussed in Note 1 to the consolidated financial statements, effective December 31, 2003, the Company changed its method of accounting for its capital trust subsidiary in accordance with Financial Accounting Standards Board Interpretation No. 46R, Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Annual Report on Internal Control Over Financial Reporting appearing on page 54, that the Company maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

New York, New York
March 14, 2005

Management's Annual Report on Internal Control Over Financial Reporting

Energy East's management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of management, including the principal executive officer and principal financial officer, an evaluation was conducted of the effectiveness of the internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued by The Committee of Sponsoring Organizations of the Treadway Commission. Based on Energy East's evaluation under the framework in *Internal Control – Integrated Framework*, management concluded that Energy East's internal control over financial reporting was effective as of December 31, 2004.

Energy East management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2004, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report on page 52.

Required Certifications

On July 9, 2004, Energy East submitted to the New York Stock Exchange its Annual Chief Executive Officer Certification under Section 303A of the New York Stock Exchange Corporate Governance Rules.

Energy East filed with the Securities and Exchange Commission the Certifications of its Chief Executive Officer and Chief Financial Officer as required under Section 302 of the Sarbanes-Oxley Act of 2002. The Certifications were filed as Exhibits 31-1 and 31-2 to Energy East's Form 10-K for the fiscal year ended December 31, 2004, dated March 14, 2005.

Selected Financial Data

Year Ended December 31	2004	2003	2002[3]	2001	2000[8]
(Thousands, except per share amounts)					
Operating Revenues					
Sales and services	**$4,756,692**	$4,514,490	$3,778,026	$3,681,613	$2,905,641
Operating Expenses					
Electricity purchased and fuel used in generation	**1,570,410**	1,338,369	1,276,087	1,332,235	1,073,728
Natural gas purchased	**1,030,314**	939,464	569,794	653,469	466,480
Other operating expenses	**790,926**	813,133	667,190	535,385	411,423
Maintenance	**181,725**	203,042	160,291	139,315	108,050
Depreciation and amortization	**292,458**	299,432	240,306	202,721	164,700
Other taxes	**252,860**	269,238	229,158	192,345	165,537
Restructuring expenses	**-**	-	40,567	-	-
Gain on sale of generation assets	**(340,739)**	-	-	(84,083)	-
Deferral of asset sale gain	**228,785**	-	-	71,803	-
Total Operating Expenses	**4,006,739**	3,862,678	3,183,393	3,043,190	2,389,918
Operating Income	**749,953**	651,812	594,633	638,423	515,723
Writedown of Investment	**-**	-	12,209	78,422[5]	-
Other (Income) and Deductions	**(19,693)**	10,860	3,928	(14,445)	(31,835)
Interest Charges, Net	**276,890**	284,790	256,161	216,387	152,520
Preferred Stock Dividends of Subsidiaries	**3,691**	19,009	32,129	14,455	963
Income From Continuing Operations Before Income Taxes	**489,065**	337,153	290,206	343,604	394,075
Income Taxes	**251,444**	128,663	100,277	154,865	156,663
Income From Continuing Operations	**237,621**	208,490	189,929	188,739	237,412
Discontinued Operations					
Loss from discontinued operations (including loss on disposal of $(7,565) in 2004 and $(13,360) in 2003)	**(7,108)**	(12,032)	(3,079)	(1,618)	(3,480)
Income taxes (benefits)	**1,176**	(13,988)	(1,753)	(486)	(1,102)
(Loss) Income From Discontinued Operations	**(8,284)**	1,956	(1,326)	(1,132)	(2,378)
Net Income	**229,337**	210,446	188,603[4]	187,607[5][6]	235,034[6]
Common Stock Dividends	**154,261**	145,417	125,456	107,342	99,606
Retained Earnings Increase	**$75,076**	$65,029	$63,147	$80,265	$135,428
Average Common Shares Outstanding, basic	**146,305**	145,535	131,117	116,708	114,213
Earnings Per Share from Continuing Operations, basic[1]	**$1.63**	$1.43	$1.45[4]	$1.62[5]	$2.08
Earnings Per Share, basic[2]	**$1.57**	$1.45	$1.44[4]	$1.61[5]	$2.06
Dividends Paid Per Share	**$1.055**	$1.00	$.96	$.92	$.88
Book Value Per Share of Common Stock at Year End	**$17.89**	$17.57	$16.97	$15.26	$14.59
Capital Spending	**$299,263**	$302,512	$229,387	$222,875	$168,320
Total Assets	**$10,796,113**	$11,330,441	$10,944,347	$7,269,232[7]	$7,013,728[7]
Long-term Obligations, Capital Leases and Redeemable Preferred Stock	**$3,797,685**	$4,017,846	$3,721,959	$2,816,278	$2,346,814

Reclassifications: Certain amounts included in Selected Financial Data have been reclassified to conform to the 2004 presentation and to reflect discontinued operations.

(1) Earnings per share from continuing operations, diluted for 2004 is $1.62, and for all other years is the same as basic.

(2) Earnings per share, diluted for 2004 is $1.56, for 2003 is $1.44, and for all other years is the same as basic.

(3) Due to the completion of the company's merger transaction during 2002 the consolidated financial statements include RGS Energy's results beginning with July 2002.

(4) Includes the writedown of the company's investment in NEON Communications, Inc. that decreased net income $7 million and EPS 6 cents and the effect of restructuring expenses that decreased net income $24 million and EPS 19 cents.

(5) Includes the writedown the company's investment in NEON Communications, Inc. that decreased net income $46 million and EPS 39 cents.

(6) Includes goodwill amortization of $25 million in 2001 and $18 million in 2000.

(7) Does not reflect the reclassification of accrued removal costs from accumulated depreciation to a regulatory liability.

(8) Due to the completion of the company's merger transactions during 2000 the consolidated financial statements include CNE's results beginning with February 2000 and include CMP Group's, CTG Resources' and Berkshire Energy's results beginning with September 2000.

Energy Distribution Statistics

	2004	2003	2002	2001	2000
(Thousands)					
Electric Deliveries					
(Megawatt-hours)					
Residential	**11,848**	11,676	10,226	8,594	6,473
Commercial	**9,480**	9,266	8,019	6,527	4,504
Industrial	**7,446**	7,412	6,694	6,525	4,613
Other	**2,245**	2,239	1,930	1,592	1,543
Total Retail	**31,019**	30,593	26,869	23,238	17,133
Wholesale	**7,855**	5,734	5,330	6,048	6,214
Total Electric Deliveries	**38,874**	36,327	32,199	29,286	23,347
Electric Revenues					
Residential	**$1,163,887**	$1,204,228	$1,073,586	$998,846	$820,093
Commercial	**565,976**	667,802	609,165	622,996	460,453
Industrial	**284,608**	344,352	313,622	314,527	263,633
Other	**177,029**	191,756	175,130	162,987	153,283
Total Retail	**2,191,500**	2,408,138	2,171,503	2,099,356	1,697,462
Wholesale	**402,122**	233,331	190,090	238,094	212,630
Other	**187,700**	117,226	206,654	167,446	113,518
Total Electric Revenues	**$2,781,322**	$2,758,695	$2,568,247	$2,504,896	$2,023,610
Natural Gas Deliveries					
(Dekatherms)					
Residential	**82,574**	85,401	62,748	52,846	42,238
Commercial	**26,493**	25,938	21,190	20,699	15,823
Industrial	**4,062**	3,458	2,934	2,847	2,690
Other	**11,276**	11,301	14,507	12,726	10,074
Transportation of customer-owned natural gas	**84,039**	86,647	80,480	58,882	37,314
Total Retail	**208,444**	212,745	181,859	148,000	108,139
Wholesale	**1,593**	5,360	7,074	9,298	10,674
Total Natural Gas Deliveries	**210,037**	218,105	188,933	157,298	118,813
Natural Gas Revenues					
Residential	**$1,020,544**	$944,010	$594,279	$576,115	$390,794
Commercial	**287,926**	266,409	192,023	226,215	145,318
Industrial	**36,147**	27,312	20,883	26,220	19,339
Other	**100,440**	86,162	83,735	89,524	68,652
Transportation of customer-owned natural gas	**89,843**	99,896	84,927	73,213	59,901
Total Retail	**1,534,900**	1,423,789	975,847	991,287	684,004
Wholesale	**182**	21,070	17,260	37,748	55,184
Other	**14,068**	17,268	39,432	(2,911)	32,943
Total Natural Gas Revenues	**$1,549,150**	$1,462,127	$1,032,539	$1,026,124	$772,131

Board of Directors

Richard Aurelio, a director since 1997, formerly President of Time Warner Cable Group New York and NY1 News, is now a director of the Javits Foundation, all in New York, New York, and Communications Dispute Resolutions, LLC in Miami, Florida.

John T. Cardis, a director since January 2005, formerly a partner of Deloitte & Touche USA, LLP, New York, New York, is a director of Edwards Lifesciences Corporation, in Irvine, California and Avery Dennison Corporation, in Pasadena, California.

James A. Carrigg, a director since 1983, is a director of Security Mutual Life Insurance Company of New York and National Security Life and Annuity Company, both in Binghamton, New York.

Joseph J. Castiglia, a director since 1995, is Chairman of HealthNow New York, Inc., DBA Blue Cross & Blue Shield of Western New York in Buffalo, New York, and Blue Shield of Northeastern New York in Albany, New York.

Lois B. DeFleur, a director since 1995, is President of Binghamton University in Binghamton, New York.

G. Jean Howard, a director since 2002, is Executive Director of Wilson Commencement Park in Rochester, New York.

David M. Jagger, a director since 2000, is President and Treasurer of Jagger Brothers, Inc. in Springvale, Maine.

Seth A. Kaplan, a director since January 2005, formerly a partner of Wachtell, Lipton, Rosen & Katz, New York, New York, is a Coadjutant member of the faculty at Rutgers University School of Law – Newark, in Newark, New Jersey.

John M. Keeler, a director since 1989, is counsel at Hinman, Howard & Kattell, LLP, attorneys-at-law in Binghamton, New York.

Ben E. Lynch, a director since 1987, is President of Winchester Optical Company in Elmira, New York.

Peter J. Moynihan, a director since 2000, formerly Senior Vice President and Chief Investment Officer of UNUM Corporation in Portland, Maine.

Walter G. Rich, a director since 1997, is Chairman, President, Chief Executive Officer and a director of Delaware Otsego Corporation in Cooperstown, New York, and its subsidiary, The New York, Susquehanna & Western Railway Corporation.

Wesley W. von Schack, a director since 1996, is Chairman, President & Chief Executive Officer of the corporation.

Committees (Chairperson listed first)

Audit: Lynch, Castiglia, DeFleur, Jagger; *Compensation and Management Succession:* Castiglia, Aurelio, Lynch; *Corporate Responsibility:* Carrigg, Howard, Keeler, Moynihan, Rich; *Nominating and Corporate Governance:* Aurelio, DeFleur, Rich

Energy East Officers

Robert M. Allessio, Chairman and Chief Executive Officer – Berkshire Gas and Executive Vice President – CNG and SCG

Richard R. Benson, Vice President – Administrative Services

Sara J. Burns, President – CMP

Michael I. German, President – CNG and SCG

Kenneth M. Jasinski, Executive Vice President and Chief Financial Officer

Robert D. Kump, Vice President, Treasurer & Secretary

James P. Laurito, President – NYSEG and RG&E

F. Michael McClain, Vice President – Finance and Chief Integration Officer

Patrick T. Neville, Vice President – Information Technology

Clifton B. Olson, Vice President – Supply

Jessica S. Raines, Vice President – Supply Chain

Robert E. Rude, Vice President and Controller

Angela M. Sparks-Beddoe, Vice President – Public Affairs

Carl A. Taylor, President – The Energy Network, Inc.

Karen L. Zink, President – Berkshire Gas

Shareholder Services

Mellon Investor Services LLC (Mellon) is transfer agent, registrar, recordkeeper, disbursing agent and administrator of the Investor Services Program for all Energy East common stock.

Mellon Internet Address: www.melloninvestor.com

Mellon's Internet Web site provides shareholders access to Investor Service Direct (ISD). Through ISD, shareholders can view their account profiles, stock certificate and book-entry histories, dividend reinvestment transactions, current stock price quote and historical stock closing prices. Shareholders may also request a replacement dividend check, the issuance of stock certificates or the sale of shares from their Investor Services Program account.

Shareholders may also contact Mellon by telephone at **1-800-542-7480**. Mellon's automated telephone service is available 24 hours a day, seven days a week. Mellon's customer service representatives are available on regular business days between 9:00 a.m. and 7:00 p.m. (Eastern Time).

Shareholders may obtain a free copy of Form 10-K, which is filed each year with the Securities and Exchange Commission, by contacting Investor Relations.

Investor Relations

Members of the financial community may contact our Manager, Investor Relations by telephone at 207-688-4336 or by fax at 207-688-4354.

Annual Meeting

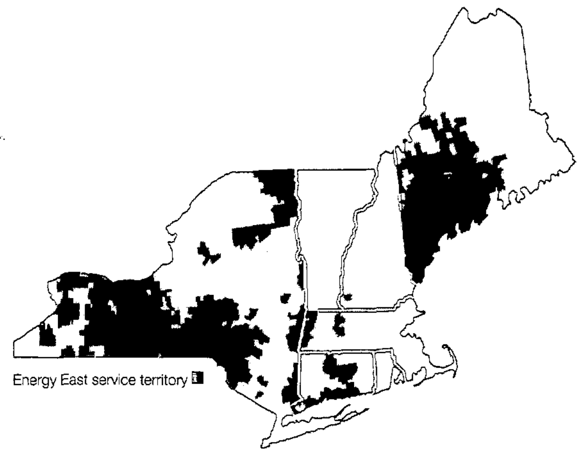
Formal notice of the meeting, a proxy statement and form of proxy will be mailed to shareholders.

Trading Symbol: EAS

EAS is the trading symbol for Energy East Corporation common stock listed on the New York Stock Exchange.

Energy East Internet Address: www.energyeast.com

Information of interest to shareholders, including financial documents and news releases, is available at our Web site.



State	Berkshire Gas Massachusetts	CMP Maine	CNG Connecticut	NYSEG New York	RG&E New York	SCG Connecticut
Electricity customers		580,000		854,000	358,000	
Natural gas customers	36,000		154,000	254,000	295,000	173,000
Electricity delivered (gwh)		11,590		17,799	9,485	
Natural gas delivered (000 dth)	7,489		33,646	60,739	53,567	29,855
Electricity revenue ($ million)		596		1,530	665	
Natural gas revenue ($ million)	66		353	434	369	341
Assets ($ million)	225	1,822	830	3,674	2,320	1,011

Energy East Corporation
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The Berkshire Gas Company (Berkshire Gas)
115 Cheshire Road | Pittsfield, MA 01201 | www.berkshiregas.com

Central Maine Power Company (CMP)
83 Edison Drive | Augusta, ME 04336 | www.cmpco.com

Connecticut Natural Gas Company (CNG)
77 Hartland Street | 4th Floor | East Hartford, CT 06108 | www.cngcorp.com

New York State Electric & Gas Corporation (NYSEG)
J. A. Carrigg Center – 18 Link Drive | P.O. Box 5224 | Binghamton, NY 13902-5224 | www.nyseg.com

Rochester Gas and Electric Corporation (RG&E)
89 East Avenue | Rochester, NY 14649-0001 | www.rge.com

The Southern Connecticut Gas Company (SCG)
855 Main Street | Bridgeport, CT 06604 | www.soconngas.com

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