shareholders.

PART II

Item 5. Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange. The number of shareholders of record was 29,896 at January 31, 2007.

Quarter Ended	March 31	June 30	September 30	December 31
2006				
Dividends Declared per Share	**$.29**	**$.29**	**$.29**	**$.30**
Common Stock Price				
High	**$25.57**	**$25.39**	**$25.20**	**$25.66**
Low	**$22.98**	**$22.18**	**$23.36**	**$23.62**
2005				
Dividends Declared per Share	$.275	$.275	$.275	$.29
Common Stock Price				
High	$26.95	$30.07	$29.35	$25.95
Low	$24.98	$25.09	$24.82	$22.50

RGS Energy, a wholly-owned subsidiary of Energy East, owns all of RG&E's common stock. See Item 8 - RG&E's Statements of Changes in Common Stock Equity for information regarding dividends declared.

Equity Compensation Plan Information

The following table provides information as of December 31, 2006, with respect to shares of common stock that may be issued under Energy East's 2000 Stock Option Plan and its Restricted Stock Plan.

Plan category	(a) Number of securities to be issued upon exercise of outstanding options and SARs	(b) Weighted-average exercise price of outstanding options and SARs	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity Compensation Plan Approved by Stockholders (2000 Stock Option Plan)	3,658,555	$24.03	6,731,246
Equity Compensation Plan Not Approved by Stockholders (Restricted Stock Plan) (1)	N/A	N/A	995,624
Total	3,658,555		7,726,870

(1) See Item 8 - Note 12 to our Consolidated Financial Statements for information regarding the Restricted Stock Plan.

Issuer Purchases of Equity Securities

Energy East Corporation

Period	(a) Total number of shares purchased	(b) Average price paid per share	(c) Total number of shares purchased as part of publicly announced plans or programs	(d) Maximum number of shares that may yet be purchased under the plans or programs
Month #1 (October 1, 2006 to October 31, 2006)	4,941[1]	$24.03	-	-
Month #2 (November 1, 2006 to November 30, 2006)	4,919[1]	$23.94	-	-
Month #3 (December 1, 2006 to December 31, 2006)	6,189[1]	$25.32	-	-
Total	16,049	$24.50	-	-

(1) Represents shares of our common stock (Par Value $.01) purchased in open-market transactions on behalf of our Employees' Stock Purchase Plan.

RG&E had no issuer purchases of equity securities during the quarter ended December 31, 2006.

Item 6. Selected Financial Data

See the information under the heading Selected Financial Data for Energy East, which is included on page II-23.

RG&E meets the conditions set forth in General Instruction I (1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, the Item 6 information related to RG&E is not presented.

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

See the information under the heading Management's Discussion and Analysis of Financial Condition and Results of Operations for Energy East, which is included in this report on pages II-24 to II-55.

RG&E meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format and is therefore including a management's narrative analysis of the results of operations as specified in General Instruction I(2)(a) of Form 10-K. See information under the heading Management's Narrative Analysis of Results of Operations for RG&E, which is included in this report on pages II-97 to II-98.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

See Item 7 - MD&A - Market Risk for Energy East and see the Notes to Financial Statements in Item 8 that are referred to in Energy East's Market Risk disclosure.

See Item 7A - Quantitative and Qualitative Disclosures about Market Risk for RG&E on page II-99 and see the Notes to Financial Statements in Item 8 that are referred to in RG&E's Item 7A disclosures.

Item 8. Financial Statements and Supplementary Data

Index to 2006 Financial Statements

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

None for Energy East or RG&E.

Item 9A. Controls and Procedures

Management's Annual Report on Disclosure Controls and Procedures

The principal executive officers and principal financial officers of Energy East and RG&E evaluated the effectiveness of their respective company's disclosure controls and procedures as of the end of the period covered by this report. "Disclosure controls and procedures" are controls and other procedures of a company that are designed to ensure that information required to be disclosed by the company in the reports that it files or submits under the Securities Exchange Act of 1934, within the time periods specified in the SEC rules and forms, is recorded, processed, summarized and reported, and is accumulated and communicated to the company's management, including its principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Based on their evaluation, the principal executive officers and principal financial officers of Energy East and RG&E concluded that their respective company's disclosure controls and procedures are effective.

Energy East 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 accounting principles generally accepted in the United States of America. 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, 2006.

Energy East management's assessment of the effectiveness of its internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report on page II-94.

Changes in Internal Control over Financial Reporting

On October 1, 2006, RG&E modified certain internal controls over financial reporting to accommodate the implementation of a new customer care system. The customer care system is used for customer bill production and integrates RG&E's revenue, accounts receivable and cash management transactions with Energy East's centralized accounting system.

There were no other changes in Energy East's or RG&E's internal control over financial reporting that occurred during each company's most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the respective company's internal control over financial reporting.

Item 9B. Other Information

None for Energy East or RG&E.

Selected Financial Data

Energy East Corporation

(Thousands, except per share amounts)	2006	2005	2004	2003	2002 (1)
Operating Revenues	**$5,230,665**	$5,298,543	$4,756,692	$4,514,490	$3,778,026
Depreciation and amortization	**$282,568**	$277,217	$292,457	$299,430	$240,306
Other taxes	**$249,834**	$246,271	$252,860	$269,238	$229,158
Interest Charges, Net	**$308,824**	$288,897	$276,890	$284,482	$256,161
Income from Continuing Operations	**$259,832**	$256,833	$237,621	$208,490	$189,929
Net Income	**$259,832**	$256,833	$229,337	$210,446	$188,603 (2)
Earnings per Share from Continuing Operations, basic	**$1.77**	$1.75	$1.63	$1.43	$1.45 (2)
Earnings per Share from Continuing Operations, diluted	**$1.76**	$1.74	$1.62	$1.43	$1.45 (2)
Earnings per Share, basic	**$1.77**	$1.75	$1.57	$1.45	$1.44 (2)
Earnings per Share, diluted	**$1.76**	$1.74	$1.56	$1.44	$1.44 (2)
Dividends Declared per Share	**$1.17**	$1.115	$1.055	$1.00	$.96
Average Common Shares Outstanding, basic	**146,962**	146,964	146,305	145,535	131,117
Average Common Shares Outstanding, diluted	**147,717**	147,474	146,713	145,730	131,117
Utility Capital Spending	**$408,231**	$331,294	$299,263	$289,320	$229,387
Total Assets	**$11,562,401**	$11,487,708	$10,796,622	$11,330,441	$10,944,347
Long-term Obligations, Capital Leases and Redeemable Preferred Stock	**$3,726,709**	$3,667,065	$3,797,685	$4,017,846	$3,721,959

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

(2) Includes the writedown of our 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.

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

Energy East Corporation

Overview

Energy East's primary operations, our electric and natural gas utility operations, are subject to rate regulation established predominately by state utility commissions. The approved regulatory treatment on various matters significantly affects our financial position, results of operations and cash flows. We have long-term rate plans for NYSEG's natural gas segment, RG&E, CMP and Berkshire Gas that currently allow for recovery of certain costs, including stranded costs; and provide stable rates for customers and revenue predictability. Where long-term rate plans are not in effect, we monitor the adequacy of rate levels and file for new rates when necessary. NYSEG's five-year electric rate plan expired December 31, 2006, and new rates went into effect on January 1, 2007. SCG received approval for new rates that became effective January 1, 2006, and CNG recently entered into a settlement agreement that, if approved, will result in new rates effective April 1, 2007. As of January 31, 2007, Energy East had 5,884 employees.

We continue to focus our strategic efforts on the areas that have the greatest effect on customer satisfaction and shareholder value. NYSEG implemented a new customer care system in the first quarter of 2006 and RG&E implemented a similar system in October 2006.

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 our operations and the rates that our customers pay for energy. Those proceedings, which are discussed below, could affect the nature of the electric and natural gas utility industries in New York and New England.

We expect to make significant capital investments to enhance the safety and reliability of our distribution systems and to meet the growing energy needs of our customers in an environmentally responsible manner. Capital spending is expected to exceed $3 billion through 2011, including $496 million in 2007. Major spending programs include the installation of advanced metering infrastructure in New York and Maine requiring a $500 million investment; $500 million of transmission investments, predominantly in Maine; a high efficiency transformer replacement program; and a "green" fleet initiative. The majority of these planned transmission investments will be pursuant to a regional reliability planning process and will qualify for the FERC's transmission investment ROE incentive adders. (See New England RTO.) We will also be investigating the repowering of the Russell Station using clean coal technologies, at a potential estimated cost of approximately $500 million. We estimate that over one-half of our capital spending program will be funded with internally generated funds and the remainder through the issuance of a combination of debt and equity securities.

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

Energy East Corporation

Strategy

We have maintained a consistent energy delivery and services strategy over the past several years, focusing on the safe, secure and reliable transmission and distribution of electricity and natural gas. Our operating companies have become increasingly efficient through realization of merger-enabled synergies. The company intends to augment this strategic focus by addressing many of the precepts of the Energy Policy Act of 2005 including: a) investing in transmission to increase reliability, meet new load growth and connect new, renewable generation to the grid; b) investing in advanced metering infrastructure to promote customer conservation and peak load management; c) investing in our distribution infrastructure to make it more efficient by reducing losses; and d) investing in new regulated generation that is environmentally friendly and, where possible, sustainable.

Our individual company rate plans are a critical component of our success. While specific provisions may vary among our public utility subsidiaries, our overall strategy includes creating stable rate environments that allow those subsidiaries to earn a fair return while minimizing price increases and sharing achieved savings with customers.

Electric Delivery Rate Overview

Our electric delivery business consists primarily of our regulated electricity transmission, distribution and generation operations in upstate New York and Maine. The electric industry is regulated by various state and federal agencies, including state utility commissions and the FERC. The following is a brief overview of the principal rate agreements in effect for each of our electric utilities.

Electric Rate Plans: NYSEG had an electric rate plan that took effect as of January 1, 2002, and expired on December 31, 2006. That rate plan provided for equal sharing of the greater of ROEs in excess of 12.5% on electric delivery, or 15.5% on the total electric business (including commodity earnings that over the term of the rate plan were estimated to be $25 million to $40 million on an annual basis based on future energy prices at the time the plan was approved) for each of the years 2003 through 2006. For purposes of earnings sharing, NYSEG was required to use the lower of its actual equity or a 45% equity ratio. At December 31, 2006, the equity NYSEG used for earnings sharing approximated $740 million, which was based on the 45% equity ratio limitation. Earnings levels were sufficient to generate estimated pretax sharing with customers of $5 million in 2006, $28 million in 2005, and $17 million in 2004.

On August 23, 2006, the NYPSC issued an order requiring that NYSEG reduce its electric delivery rates by approximately $36 million, or approximately 6%, effective January 1, 2007. (See NYSEG Electric Rate Order .)

RG&E's current rates were established by the 2004 Electric Rate Agreement, which addresses RG&E's electric rates through at least 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, to recover $7 million annually. An ASGA was established that was originally estimated to be $145 million at the end of 2008 and will be used at that time for rate moderation or other purposes at the discretion of the NYPSC. The

Electric Rate Agreement also established an earnings-sharing mechanism to allow customers and shareholders to share equally in earnings above a 12.25% ROE target. Earnings levels were sufficient to generate $6 million of pretax sharing in 2006 and $23 million in 2005.

NYSEG and RG&E currently offer their retail customers choice in their electricity supply including a fixed rate option, a variable rate option under which rates vary monthly based on the actual cost of electricity purchases and an option to purchase electricity supply from an ESCO. Both NYSEG's and RG&E's customers make their supply choice annually. Those customers who do not make a choice are served under a variable price option. Customers also pay nonbypassable wires charges, which include recovery of stranded costs. The table below shows the percentages of load that are projected to be served under the various commodity supply options for 2007.

	NYSEG	RG&E
Fixed Price Option	17%	21%
Variable Price Option	45%	29%
Energy Service Company Option	38%	50%

Experience has shown that the majority of our residential and small commercial customers want their utility to remain a supply option and prefer a fixed price option. NYSEG and RG&E believe that their programs are among the most successful of any retail access plans in New York State in terms of active participation and customer migration. In addition, their programs have produced customer benefits in excess of $130 million through 2006. Customer benefits include the customer's portion of earnings sharing and costs that were absorbed by NYSEG and RG&E that would otherwise have been deferred for future recovery had earnings levels been insufficient to generate sharing.

CMP's distribution costs are recovered under the ARP 2000, which became effective January 1, 2001, and continues through December 31, 2007, with price changes, if any, occurring on July 1. CMP's annual delivery rate adjustments are based on inflation with productivity offsets of 2.75% in 2006 and 2.9% in 2007. Price adjustments since 2002 have generally resulted in rate decreases.

CMP uses formula rates for transmission that are FERC regulated. The formula rates provide for the recovery of CMP's cost of owning, operating and maintaining its local and regional transmission facilities and local control center, including a FERC-approved base level ROE of 10.9%, plus a 50 basis point adder for regional facilities and a 100 basis point adder applicable to regional facilities placed in service after December 31, 2003, and approved as part of the ISO-NE regional planning process. The formula rates are updated annually in a filing to the FERC on June 1st. CMP's transmission rates increased approximately $20 million for the rate year effective June 1, 2006. The increase enables CMP to recover its share of ISO-NE regional transmission costs and its local transmission costs.

Pursuant to Maine statutes, 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, through its stranded cost rates. In January 2005 the MPUC approved new stranded cost rates for the three-year period ending February 2008. Any difference between actual and projected stranded costs is deferred for future refund or recovery. CMP is prohibited by state law from providing commodity service to its customers.

Electric Delivery Business Developments

NYSEG Electric Rate Order: In September 2005 NYSEG filed a six-year Electric Rate Plan Extension with the NYPSC, to commence on January 1, 2007. NYSEG's Electric Rate Plan Extension, as subsequently amended, proposed, beginning on January 1, 2007, to reduce the nonbypassable wires charge by $168 million and increase delivery rates by $104 million, thereby resulting in an annualized overall electricity delivery rate decrease of $64 million, or 8.6%. NYSEG proposed to accomplish the reduction in its nonbypassable wires charge by accelerating benefits from certain expiring above-market NUG contracts and capping the amount of above-market NUG costs over the term of the rate plan extension (referred to as NYSEG's NUG levelization proposal). NYSEG also proposed to increase its equity ratio from 45% to 50%. In addition, NYSEG's proposal would have allowed customers to continue to benefit from merger synergies and savings.

In early February 2006 Staff of the NYPSC (Staff) and six other parties submitted their direct cases. Staff presented only a one-year rate case. In its presentation, Staff proposed a delivery rate decrease of approximately $83 million, or about 13.4%. Staff neither rebutted nor addressed NYSEG's revised and updated rate plan extension proposal, including its NUG levelization proposal, and opposed NYSEG's proposal to extend its Voice Your Choice commodity program. Staff also raised several retroactive accounting issues that will be addressed in a future proceeding. The most significant of those issues concerns NYSEG's internal other post employment benefits (OPEB) reserve (explained below), which, if accepted by the NYPSC, would have a material effect on earnings.

On August 23, 2006, the NYPSC issued its order in this proceeding. Major provisions of the Order include:

- A decrease in delivery rates of $36 million. NYSEG's most recent update in the proceeding requested a $58 million increase in delivery rates.

- A 9.55% ROE. NYSEG had requested an 11% ROE.

- An equity ratio of 41.6% (approximately $610 million of equity) based on Energy East's consolidated capital structure. NYSEG had requested a 50% equity ratio based on its actual capital structure.

- A refund of $77 million to be paid from NYSEG's ASGA that had previously been reserved for customers. The ASGA was initially created in 1998 as a result of the sale of NYSEG's generating stations and had been enhanced during NYSEG's prior electric rate plans with the customers' share of earnings from the earnings sharing mechanism. Payment of the refund will be made through a credit to customers' bills by the end of April 2007.

- One retroactive accounting issue raised by Staff concerns $57 million of interest associated with NYSEG's internal OPEB reserve, which NYSEG has offset against other OPEB costs in its income statement over the past decade. The NYPSC determined that $3.6 million in annual revenues that NYSEG receives will remain subject to refund pending further examination of NYSEG's accounting for OPEB costs. A proceeding related to this issue began in the fourth quarter of 2006 and could result in NYSEG treating all or a portion of the $57 million as an addition to its internal OPEB reserve, with a corresponding charge to income. NYSEG is vigorously defending its position and contends that the NYPSC staff is engaged in retroactive ratemaking, but is unable to predict its outcome.

- Significant modifications to NYSEG's previously approved Voice Your Choice commodity program, including:

  - Use of the variable rate supply option as the default for all customers not making a supply election, rather than the previous fixed price default option.

  - A 30% reduction in the cost allowance used to set the supply rate.

  - The use of an earnings collar for supply of plus or minus $5 million pre-tax with sharing outside the collar of 80% to customers and 20% to shareholders. NYSEG previously could earn 300 basis points ROE on supply (approximately $22 million) after which earnings were shared equally.

NYSEG believes that the commodity options program in the Order is unworkable in the long-term and inconsistent with the development of a competitive retail market for supply. In particular, NYSEG believes that the lower cost allowance used to set the supply rate does not cover the cost and risk of providing fixed price electricity at retail, and will stifle participation by retail energy service providers.

NYSEG estimates that the effect of the order will be to reduce its earnings by $35 million to $45 million. This estimate includes the effects of the delivery rate reduction, the lower ROE, the lower equity base that NYSEG is allowed to earn on and the changes in the commodity program, including the revised sharing provisions.

On September 7, 2006, NYSEG filed a petition with the NYPSC for rehearing and request for oral argument responding to certain aspects of the Order including the disallowance of system implementation costs. On December 15, 2006, the NYPSC denied NYSEG's petition.

Niagara Power Project Relicensing: The NYPA's FERC license with respect to the Niagara Power Project expires on August 31, 2007. In order to continue to operate the Niagara Power Project, the NYPA filed a relicensing application in August 2005. The NYPA's relicensing process is important to NYSEG's and RG&E's customers because an aggregate of over 360 MWs of Niagara Power Project power has been allocated to the companies based on their contracts with the NYPA. (NYSEG and RG&E also receive allocations from the St. Lawrence Project pursuant to those same contracts.) The contracts expire on August 31, 2007, upon termination of the NYPA's FERC license. The annual value of the Niagara allocation to the companies at current electricity market prices is approximately $77 million and the loss of the

allocation would increase NYSEG's and RG&E's residential customer rates. However, the NYPA has stated that the allocation of Niagara Power Project power to NYSEG and RG&E should not be addressed in the relicensing proceeding and that the disposition of the power will be in accordance with state and federal requirements.

Advanced Metering Infrastructure: In February 2007 in response to an August 2006 NYPSC order, NYSEG and RG&E filed a plan to install advanced metering infrastructure (smart meters) for all of their electric and natural gas customers. Smart meters would enable customers to better control their energy usage by providing time-differentiated rates. Smart meters would also improve the companies' response to service interruptions, enhance safety, and provide internal usage and demand data that will ultimately lead to peak demand reduction and defer the need for generation sources. The plan calls for a total capital investment of approximately $370 million between 2008 and 2010.

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. The incident occurred outside of our service territory. All New York utilities were directed to respond to that order by February 19, 2005, with a report that provided 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 also established penalties for failure to achieve annual performance targets for testing and inspections, at 75 basis points each.

In early February 2005 NYSEG and RG&E filed, with two other New York State utilities, a joint petition for rehearing that focused on several areas including the impracticability of the timetable established in the order. In response to the order, in late February 2005 NYSEG and RG&E filed a testing and inspection plan that is consistent with the timetable identified in the joint petition for rehearing. NYSEG and RG&E are implementing their plans, including testing of equipment. On July 21, 2005, in response to the petition for rehearing, the NYPSC issued an order detailing the revised requirements for stray voltage testing and reduced penalties during the first year to 37.5 basis points. NYSEG and RG&E filed the required annual reports with the NYPSC on January 17, 2006. In August 2006 NYSEG and RG&E completed their first complete cycle of testing and at the request of the NYPSC, submitted an interim report on October 23, 2006, detailing their results. Under the provisions of their respective rate plans, they are allowed to defer and recover these costs.

For 2006, costs incurred to comply with the order were approximately $4 million for NYSEG and $2 million for RG&E. For 2007, estimated additional costs to comply with the order are approximately $6 million for NYSEG and $3 million for RG&E.

RG&E Transmission Project: In December 2004 RG&E received approval from the NYPSC to upgrade its electric transmission system in order to provide sufficient transmission and ensure reliable service to customers in anticipation of the shutdown of the Russell Station. The project includes building or rebuilding 38 miles of transmission lines and upgrading substations in the Rochester, New York area. In August 2005 RG&E selected the team of EPRO Engineering, E.S. Boulos and O'Connell Electric Company for the project. Construction on the project began in the first quarter of 2006 and is expected to be completed by December 2007. The estimated cost of the project is approximately $119 million.

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

Energy East Corporation

RG&E Dispute Settlement Related to NMP2 Exit Agreement: In November 2001 RG&E and three other NMP2 joint owners, including Niagara Mohawk Power Corporation (Niagara Mohawk), sold their interests in NMP2 to Constellation Nuclear, LLC. In connection with the sale of NMP2, RG&E informed Niagara Mohawk that RG&E's payment obligations and rights to certain TCCs would cease according to the terms of an exit agreement executed by RG&E and Niagara Mohawk in June 1998. Niagara Mohawk disagreed with RG&E's position, claiming that RG&E must continue to make annual payments that were to decline from about $7 million per year in 2002 to $4 million per year in 2007, and remain at that level until 2043. In August 2001, RG&E filed a complaint asking the New York State Supreme Court, Monroe County, to find that, as a result of the sale of its interest in NMP2, RG&E has no further obligation to make payments under the exit agreement and that the TCCs to which RG&E was entitled under the exit agreement should be returned to and accepted by Niagara Mohawk.

In the first quarter of 2006, RG&E and Niagara Mohawk stayed the litigation and entered into confidential mediation with an ALJ appointed by the NYPSC. On June 29, 2006, the parties executed a settlement agreement that provides for RG&E's one-time payment of $34 million to Niagara Mohawk and further provides that RG&E retain the rights and obligations related to the TCCs until 2043, including the value accumulated to date of approximately $4 million. The settlement agreement was contingent upon the fulfillment of certain closing conditions, including FERC acceptance of an amendment to and restatement of the exit agreement. All of the necessary closing conditions were fulfilled, including a favorable judgment from the FERC and the lack of a negative finding by the Director of Accounting and Finance of the NYPSC, and RG&E made the required payment. In accordance with the 2001 settlement and order associated with the transfer of RG&E's share of NMP2 to Constellation Nuclear and RG&E's Electric Rate Agreement, RG&E adjusted its regulatory asset established as a result of the sale of NMP2 for the amount of the $34 million payment to Niagara Mohawk, which was offset by the accumulated TCC amount of approximately $4 million. The payment will also be adjusted by any future TCC amounts. RG&E's results of operations were not affected by the settlement of this dispute. The current amortization and recovery of this regulatory asset in rates remains unchanged.

Threatened Litigation for Russell Station: In October 1999 RG&E received a letter from the New York State Attorney General's office alleging that RG&E may have constructed and operated major modifications to the Beebee and Russell generating stations without obtaining the required prevention of significant deterioration or new source review permits. The letter requested that RG&E provide the Attorney General's office with a large number of documents relating to this allegation. In January 2000 RG&E received a subpoena from the NYSDEC ordering production of similar documents. RG&E supplied documents and complied with the subpoena.

The NYSDEC served RG&E with a notice of violation in May 2000 alleging that between 1983 and 1987 RG&E completed five projects at Russell Station, and two projects at Beebee Station, which is currently shut down, without obtaining the appropriate permits. RG&E believes it has complied with the applicable rules and there is no basis for the Attorney General's and the NYSDEC's allegations. Beginning in July 2000 the NYSDEC, the Attorney General and RG&E had a number of discussions with respect to the resolution of the notice of violation. In October 2006 the Attorney General's office and the NYSDEC notified RG&E of their intention to file a complaint in federal court for violations at Russell Station unless a settlement can be reached.

Were the Attorney General and the NYSDEC to commence a Clean Air Act lawsuit against RG&E, they would need to demonstrate, among other things, that the challenged modifications to the Russell generating station cause an "increase" in emissions from the station. The issue of what constitutes the appropriate test for an emissions increase currently is before the United States Supreme Court in Environmental Defense v. Duke Energy Corporation, Docket No. 05-848. Oral argument was held on November 2006, and a decision is expected in the first half of 2007. RG&E, the NYSDEC and the Attorney General continue to discuss this matter and no suit has been filed to date. RG&E is not able to predict the outcome of this matter.

CMP Alternative Rate Plan: In December 2005 CMP and the Maine Office of the Public Advocate filed with the MPUC a stipulation for an extension of CMP's ARP 2000. The stipulation was also supported by low-income customer advocates, and a coalition of industrial energy customers signed the stipulation agreement. The stipulation maintained the provisions of CMP's ARP 2000 and proposed a three-year extension with four additional items: (i) a 0.5% increase in the scheduled productivity offset of 2.75% for July 2006 and provided for productivity offsets

averaging 2% for 2008, 2009 and 2010, (ii) an additional $2.2 million in assistance for low-income customers annually starting in 2006, (iii) CMP agreed to educate its customers on the regional benefits of adjusting usage during peak hours and demand periods and also agreed to limit the promotion of increased usage during specified higher demand periods and (iv) CMP agreed to commit to investing an additional $25 million through 2010 for enhancements to the reliability, safety and security of its distribution system.

In February 2006 the MPUC approved that portion of the stipulation increasing assistance to low-income customers for one year. On April 28, 2006, the Staff of the MPUC filed its analysis and recommendations with the MPUC commissioners, opposing the stipulation other than the portion that was approved. CMP and the other stipulating parties responded to the Staff's recommendations in a brief filed on May 19, 2006. On June 5, 2006, the MPUC determined that the stipulation was not in the public interest unless substantially modified, and on June 21, 2006, the MPUC agreed to dismiss the proceeding at the request of the stipulating parties. CMP will file a proposal for a new alternative rate plan by May 1, 2007, to be effective January 1, 2008. In the interim, CMP continues to operate under the terms of ARP 2000.

CMP Electricity Supply Responsibility: Under Maine statutes, CMP's customers can choose to arrange for competitive energy supply or take default supply under standard-offer service as arranged by the MPUC. The MPUC conducts periodic supply solicitations for standard-offer service by customer class. If the MPUC does not accept any competitive supply bid for a standard offer arrangement, the MPUC can mandate that CMP be a standard-offer provider of electricity supply service for retail customers and CMP would recover all costs of such an arrangement in rates. As of January 2007, the MPUC has approved standard-offer service arrangements for all of CMP's customer classes through competitive solicitation. The supply prices and terms of the arrangements vary by class, including a laddered three-year arrangement for residential and small commercial customers that solicits one-third of the supply each year and a six-month arrangement for medium and large commercial and industrial customers.

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

Energy East Corporation

CMP Nuclear Costs: CMP owns shares of stock in three companies that own nuclear generating facilities in New England that have been permanently shut down, and are decommissioned or in 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). Each of the three facilities has an established NRC licensed independent spent fuel storage installation on site to store spent nuclear fuel in dry casks until the DOE takes the fuel for disposal. 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 for spent nuclear fuel disposal. The contracts provided for the federal government to begin removing spent nuclear fuel from 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 breached its contracts with the Yankee companies and other utilities. A trial in the U.S. Court of Federal Claims to determine the monetary damages owed to the Yankee companies for the DOE's continued failure to remove spent nuclear fuel concluded 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.

On September 30, 2006, the U.S. Court of Federal Claims issued a favorable ruling for the three Yankee companies in their litigation with the federal government over its failure to remove spent nuclear fuel from the three former nuclear power plant sites. In the ruling, Yankee Atomic was awarded $33 million in damages for costs through 2001, Connecticut Yankee was awarded $34 million for costs through 2001, and Maine Yankee was awarded $76 million for costs through 2002. CMP's sponsor-weighted share of the award is approximately $34 million. Since spent nuclear fuel continues to be stored at the sites, the Yankee companies will have the opportunity to recover more damages in future lawsuits. On December 4, 2006, the federal government appealed the decision, delaying payment of the damage awards. Any awards ultimately received will be credited to the Yankee companies' respective electric ratepayer-funded, decommissioning or spent fuel trust funds. CMP cannot predict the ultimate outcome of this matter.

Pursuant to a FERC approved settlement, in July 2004 Connecticut Yankee filed for FERC approval of a revised schedule of decommissioning charges to be collected from its wholesale customers, based on an updated estimate of decommissioning costs. Estimated decommissioning and long-term spent fuel storage costs for the period 2000 through 2023 increased by approximately $390 million in 2003 dollars and result in annual collections of $93 million from Connecticut Yankee's owners, including CMP. The revised estimate reflects increases in the projected costs for spent fuel storage, security, liability and property insurance and the fact that Connecticut Yankee had to take over all work to complete the decommissioning of the plant due to its termination of its contract with Bechtel, the turnkey decommissioning contractor, in July 2003. On August 11, 2006, Connecticut Yankee filed a settlement agreement supported by all parties, including the FERC trial staff, that resolved all of the issues contested and will allow Connecticut Yankee to collect the increased decommissioning costs. FERC approved the settlement agreement in November 2006. The revised decommissioning charges will be collected in wholesale rates effective January 1, 2007, until December 2015.

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

Energy East Corporation

Nonutility Generation: We expensed approximately $560 million for NUG power in 2006 and we estimate that our combined NUG power purchases will total $568 million in 2007, $392 million in 2008, $229 million in 2009, $84 million in 2010 and $85 million in 2011. 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 2006, averaged 10.2 cents per kilowatt-hour for CMP and 11.3 cents per kilowatt-hour for NYSEG. Recovery of these NUG costs is provided for in CMP's stranded cost rates and in NYSEG's rates through a nonbypassable wires charge. (See Item 8 - Note 9 to our Consolidated Financial Statements.)

New England RTO: In March 2004 the FERC issued an order that accepted a six-state New England RTO that CMP participates in and which is operated by ISO-NE and the New England transmission owners. The RTO began operations effective February 1, 2005. As an RTO, ISO-NE is responsible for the independent operation of the regional transmission system and regional wholesale energy market. The transmission owners retain ownership of their transmission facilities and control over their revenue requirements. The FERC also approved both a 50 basis point ROE incentive adder for regional transmission facilities subject to RTO control and a 100 basis point ROE incentive adder for new regional transmission facilities approved as part of the regional planning process. The New England transmission owners appealed the application of the adders to local facilities to the Circuit Court of Appeals for the

District of Columbia. Other parties appealed the FERC's decision to grant the adders to regional facilities. On June 30, 2006, the Court denied the appeals and upheld the FERC's decisions. On October 31, 2006, the FERC issued an Opinion and Order on Initial Decision establishing the ROE applicable to the RTO, including CMP's transmission system. The October 31 order adopts a base-level ROE of 10.2 percent, with three adjustments as follows: a 50 basis point incentive for RTO participation; a 100 basis point incentive for new transmission investment; and a 74 basis point adjustment reflecting updated bond data, as applicable to the period commencing with the date of the order. The resulting ROEs for existing regional transmission facilities were 10.7 percent for the period February 1, 2005, through October 31, 2006, and are 11.4 percent for the going-forward period.

The ROEs that will apply to post-2003 regional transmission facilities approved as part of the regional reliability planning process will include an incremental 100 basis point adder, and are 11.7 percent prior to the date of the order, and 12.4 percent for the going-forward period. Several parties have filed for rehearing of the order and can appeal the final order. The New England transmission owner filing parties submitted a filing in compliance with the order on December 21, 2006 to establish a refund and billing procedure as required by the final Order. On February 6, 2007, several parties filed a late protest to this compliance filing. CMP cannot predict the outcome of these proceedings.

Locational Installed Capacity Markets: In 2003 the FERC required ISO-NE 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-NE developed and filed with the FERC a market proposal based on an administratively set demand curve (previously referred to as locational installed capacity or LICAP). In June 2005 the FERC ALJ issued an initial decision, essentially adopting the ISO-NE market proposal, with minor modifications.

CMP and other parties that oppose the ISO-NE market proposal filed exceptions to the recommended decision in July 2005. The Energy Policy Act of 2005 included a "sense of Congress" provision to the effect that the FERC should carefully consider the objections of the New England states to the proposal in the recommended decision. Following oral arguments, the FERC granted the request to conduct settlement discussions to consider alternatives. Settlement discussions began in November 2005 and in January 2006 the settlement ALJ reported to the FERC that most of the parties had reached an agreement in principle on an alternative. The alternative would provide fixed transitional capacity payments from 2006 until 2010 and provide capacity payments based on a Forward Capacity Market Auction thereafter. CMP opposed this settlement agreement because of the cost of the transition payments to electric customers in Maine. The ISO-NE and a majority of New England Power Pool (NEPOOL) participants supported the settlement agreement. That alternative has been filed with the FERC as a component of a comprehensive settlement agreement.

The MPUC, among other parties, filed comments opposing the settlement agreement, because the proposal could have an adverse effect on Maine's economy by increasing its generation supply rates, including standard offer rates, by an estimated 5% to 10%. On June 15, 2006, the FERC issued an order accepting the settlement agreement without modification. The MPUC and other parties opposed to the settlement agreement filed a request with the FERC asking it to reconsider its June 15 order. On October 31, 2006, the FERC issued an Order on Rehearing and Clarification denying requests for rehearing and affirming its approval of the settlement agreement. With the FERC's denial of the rehearing requests, the resulting increased costs associated with regional installed capacity have been reflected in Maine consumers' generation supply rates since December 2006. Several parties, including the MPUC, have filed notices of appeal in the US Circuit Court of Appeals, seeking to overturn the FERC's orders approving the settlement agreement. CMP cannot predict the outcome of these proceedings.

MPUC Inquiries into Long-Term Utility Contracting and Continued Participation in New England RTO: Maine lawmakers enacted legislation in 2005 that requires the MPUC to conduct two inquiries. The first concerns whether or not CMP and other Maine electric utilities should continue to participate in the New England RTO, as operated by the ISO-NE. In this inquiry, the MPUC issued an interim report to the Maine Legislature on January 16, 2007, reporting its preliminary findings: inequities exist in the current cost allocation system of the ISO-NE tariff; no insurmountable legal, economic or technical barriers preclude withdrawal from the ISO-NE; and reasonable alternatives exist. The MPUC has begun the next phase of this inquiry in which three options will be explored: altering the transmission cost allocation formula; exiting the RTO and creating a state-wide independent transmission company; or joining with New Brunswick and other Maritime provinces to create a Maine-Canada market. The MPUC has set a June 2007 target date for a draft report to the legislature containing recommendations for further action.

The second inquiry concerns regional energy markets and generation deregulation. The MPUC conducted an initial inquiry into the development of a Maine electric resource adequacy plan and the use of long-term generating capacity contracts between utilities and capacity suppliers and developed provisional long-term contracting rules and the first report on resource adequacy, which were submitted to the legislature for further action in early 2007. Because the proposed long-term contracting rules are considered major, substantive rules, the Maine Legislature must vote on their adoption.

CMP will continue to participate in the MPUC and subsequent legislative proceedings and cannot predict the outcome of the inquiries.

Natural Gas Delivery Rate Overview

Our natural gas delivery business consists of our regulated natural gas transportation, storage and distribution operations in New York, Connecticut, Massachusetts and Maine. The natural gas industry is regulated by various state and federal agencies, including state utility commissions. All of our natural gas utilities have a natural gas supply charge or a purchased gas adjustment clause to defer and recover actual natural gas costs. The following is a brief overview of the current rate agreements in effect for each of our natural gas utilities.

Natural Gas Rate Plans: NYSEG's Natural Gas Rate Plan, which became effective October 1, 2002, freezes overall delivery rates through December 31, 2008, and contains an earnings-sharing mechanism, a weather normalization adjustment mechanism and a gas cost incentive mechanism. The earnings-sharing mechanism requires equal sharing of earnings between NYSEG customers and shareholders of ROEs in excess of 12.5% 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 2006, 2005 or 2004.

RG&E's current rates were established by the 2004 Natural Gas Rate Agreement, which addresses RG&E's natural gas rates through 2008. Key features of the Natural Gas Rate Agreement include freezing natural gas delivery rates through December 2008, except for the implementation of a natural gas merchant function charge to recover approximately $7 million annually beginning May 1, 2004. The Natural Gas Rate Agreement also implemented a weather normalization adjustment to protect both customers and RG&E from fluctuating revenues due to swings in temperature outside a normal range, and a gas cost incentive mechanism to provide a means of sharing with customers any future gas supply cost savings that RG&E achieves. An earnings-sharing mechanism was established to allow customers and shareholders to share equally in earnings above a 12.0% ROE target. No sharing occurred in 2006, 2005 or 2004.

SCG's current rates became effective on January 1, 2006, pursuant to a settlement agreement that is in effect through December 31, 2007. The total increase in revenue requirements for firm rates was set at 8.4% or about $26.7 million and included amounts for recovery of previously deferred costs including bad debts.

CNG's IRP expired on September 30, 2005, and its rates have continued in effect since then, but the earnings sharing mechanism, the rate stay-out commitment and the exogenous cost provision were no longer applicable. On September 29, 2006, CNG filed for new rates to become effective on April 1, 2007. On December 21, 2006, CNG and other participants in the proceeding filed a settlement agreement with the DPUC for an increase of $15.5 million that would be in effect through March 31, 2008. (See CNG Regulatory Proceeding.)

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Berkshire Gas' current rate plan is a 10-year rate plan that went into effect on February 1, 2002, and runs through January 31, 2012, with a mid-period review in 2007. The plan has no ROE cap and has an annual inflationary rate adjustment that is determined based on the gross domestic product minus 1% as a productivity offset. The adjustment is made on September 1st each year. Berkshire Gas does not believe the mid-period review will result in any significant changes to its rate plan.

Natural Gas Delivery Business Developments

Natural Gas Supply Agreements: Our natural gas companies - NYSEG, RG&E, SCG, CNG, Berkshire Gas and MNG - each have a three-year strategic alliance with BP Energy Company ending on March 31, 2007, that gives them the right to acquire natural gas supply and optimizes transportation and storage services. We are exploring our options for a new alliance.

CNG Regulatory Proceeding: On March 21, 2006, the DPUC notified CNG that it had initiated a general rate review of CNG pursuant to Connecticut General Statutes, which state that the DPUC must conduct a financial review or require a rate case every four years. On September 29, 2006, CNG submitted a general rate filing, requesting a net rate increase of $28.2 million, or 7.9%, in base delivery revenues effective April 1, 2007, based on an 11.0% ROE. The requested increase includes $6.7 million for increased bad debt expense, including a hardship program, $5.6 million for sharing of achieved management efficiencies and $4.3 million to offset lower normalized customer usage.

On December 21, 2006, CNG and the OCC filed with the DPUC a proposed Settlement Agreement in which the parties have agreed to a net increase in firm revenues of $15.5 million (4.2% of total firm revenues), and a 10.1% ROE. CNG has also agreed to freeze its base distribution rates for a period of at least 30 months, until October 2009, to implement an automated meter reading system by July 2008, and to a non-firm delivery margin threshold of $8.6 million with sharing of 86% to customers and 14% to shareholders. A final decision by the DPUC is expected in April 2007.

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. Discovery is ongoing in both actions. A trial date for the RG&E action has been set for the fourth quarter of 2007. Any proceeds from these actions will go to customers. RG&E and NYSEG are unable to predict the outcome of these actions at this time.

Environmental Insurance Settlements: In 2005 we served demands on three of our liability insurance carriers seeking coverage for environmental investigation and clean-up costs incurred at three former manufactured gas plant sites located in Massachusetts. In 2006 we settled claims against two carriers for substantial cash payments from each. We are still in negotiations with the third carrier and cannot, at this time, predict the results of these negotiations. Pursuant to Massachusetts regulations, we are allowed to retain a share of these settlement proceeds for shareholders.

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

Energy East Corporation

New Accounting Standards

The FASB released FIN 48 in July 2006 and issued Statements 157 and 158 in September 2006. See Item 8 - Note 1 to our Consolidated Financial Statements for explanations about these new accounting standards and when they will become or became effective.

Contractual Obligations and Commercial Commitments

At December 31, 2006, our contractual obligations and commercial commitments are:

	Total	2007	2008	2009	2010	2011	After 201
(Thousands)							
Contractual Obligations							
Long-term debt[1]	$7,521,068	$497,028	$318,878	$365,525	$467,371	$407,927	$5,464,33
Capital lease obligations[1]	37,116	3,486	3,486	3,513	3,513	2,791	20,32
Operating leases	87,762	13,452	13,071	11,761	11,664	10,494	27,32
Nonutility generator power purchase obligations	1,821,553	567,815	392,057	229,209	83,586	84,927	463,95
Nuclear plant obligations	229,354	28,878	25,240	13,543	12,631	3,868	145,19
Unconditional purchase obligations:							
Electric	2,032,368	373,401	290,453	296,135	311,961	279,568	480,85
Natural gas	212,320	86,017	71,276	27,284	16,589	9,864	1,29
Pension and other postretirement benefits[2]	2,252,779	184,804	193,507	203,112	213,599	225,162	1,232,59
Other long-term obligations	7,179	3,727	1,621	885	596	267	8
Total Contractual Obligations	$14,201,499	$1,758,608	$1,309,589	$1,150,967	$1,121,510	$1,024,868	$7,835,95

[1] Amounts for long-term debt and capital lease obligations include future interest payments. Future interest payments on variable-rate debt are determined using established rates at December 31, 2006.

[2] Amounts are through 2016 only.

[3] The above table excludes our regulatory liabilities, deferred income taxes, asset retirement obligation and environmental remediation costs because the related future cash flows are uncertain. See Item 8 - Notes 6, 7, 9 and 14 to our Consolidated Financial Statements for additional information regarding our financial commitments at December 31, 2006.

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

Energy East Corporation

Critical Accounting Policies

In preparing our financial statements in accordance with accounting principles generally accepted in the United States of America, 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. Our most critical accounting policies include the effects of utility regulation on our financial statements, the estimates and assumptions used to perform our annual impairment analyses for goodwill and other intangible assets, to calculate pension and other postretirement benefits and to estimate unbilled revenues and the allowance for doubtful accounts.

Regulatory Assets and Liabilities: 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.

We believe our public utility subsidiaries will continue to meet the criteria of Statement 71 for their regulated electric and natural gas operations in New York, Maine, Connecticut and Massachusetts; however, we cannot predict what effect a competitive market or future actions of the NYPSC, MPUC, DPUC, DTE or FERC will have on their ability to continue to do so. If our 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 an expense or as revenue certain regulatory assets and regulatory liabilities.

Approximately 90% of our revenues are derived from operations that are accounted for pursuant to Statement 71. The rates our operating utilities charge their customers are set under cost basis regulation reviewed and approved by each utility's governing regulatory commission.

Goodwill and Other Intangible Assets: We do not amortize goodwill or intangible assets with indefinite lives. We test both goodwill and intangible assets with indefinite lives for impairment at least annually and amortize intangible assets with finite lives and review them for impairment. Impairment testing includes various assumptions, primarily the discount rate and forecasted cash flows. We conduct our impairment testing using a range of discount rates representing our 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 our determination of an impairment. We had no impairment in 2006 of our goodwill or intangible assets with indefinite lives. (See Item 8 - Note 4 to our Consolidated Financial Statements and Note 3 to RG&E's Financial Statements.)

Pension and Other Postretirement Benefit Plans: We have pension and other postretirement benefit plans covering substantially all of our employees. In accordance with Statement 87 and Statement 106, 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, mortality tables, expected years of future service under the pension benefit plans and the methodology used to amortize gains or losses.

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

Energy East Corporation

Assumptions are based on our best estimates of future events using historical evidence and long-term trends. Changes in those assumptions, as well as changes in the accounting standards related to pension and postretirement benefit plans, could have a significant effect on our noncash pension income or expense or on our postretirement benefit costs. As of December 31, 2006, we increased the discount rate from 5.50% to 5.75%. The discount rate is the rate at which the benefit obligations could presently be effectively settled. The discount rate was determined by developing a yield curve derived from a portfolio of high grade noncallable bonds that closely matches the duration of the expected cash flows of our benefit obligations. (See Item 7 - MD&A - Other Market Risk, and Item 8 - Note 14 to our Consolidated Financial Statements and Note 12 to RG&E's Financial Statements.)

Unbilled Revenues: 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 delivery loss factors. Changes in those assumptions could significantly affect the estimates of unbilled revenues. (See Item 8 - Note 1 to our Consolidated Financial Statements and Note 1 to RG&E's Financial Statements.)

Allowance for Doubtful Accounts: The allowance for doubtful accounts is our best estimate of the amount of probable credit losses in our existing accounts receivable, determined based on experience for each service region and operating segment and other economic data. Each month the operating companies review their allowance for doubtful accounts and past due accounts over 90 days and/or above a specified amount, and review all other balances on a pooled basis by age and type of receivable. When an operating company believes that a receivable will not be recovered, it charges off the account balance against the allowance. Changes in assumptions about input factors such as economic conditions and customer receivables, which are inherently uncertain and susceptible to change from period to period, could significantly affect the allowance for doubtful accounts estimates. (See Item 8 - Note 1 to our Consolidated Financial Statements and Note 1 to RG&E's Financial Statements.)

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

Energy East Corporation

Liquidity and Capital Resources

Cash Flows

The following table summarizes our consolidated cash flows for 2006, 2005 and 2004.

Year Ended December 31,	2006	2005	2004
(Thousands)			
Operating Activities			
Net income	$259,832	$256,833	$229,337
Noncash adjustments to net income	419,196	422,635	431,700
Changes in working capital	(198,307)	(95,256)	(233,246)
Other	(101,227)	(83,940)	(88,691)
Net Cash Provided by Operating Activities	379,494	500,272	339,100
Investing Activities			
Sale of generation assets	-	-	453,678
Excess decommissioning funds retained	-	-	76,593
Utility plant additions	(408,231)	(331,294)	(299,263)
Current investments available for sale, net	172,925	(57,270)	(135,655)
Other	7,547	20,133	1,600
Net Cash (Used in) Provided by Investing Activities	(227,759)	(368,431)	96,953
Financing Activities			
Net issuance of common stock	(5,764)	(3,838)	(2,988)
Net (repayments of) increase in debt and preferred stock of subsidiaries	(5,258)	30,908	(333,095)
Dividends on common stock	(167,349)	(150,367)	(136,374)
Net Cash Used in Financing Activities	(178,371)	(123,297)	(472,457)
Net Increase (Decrease) in Cash and Cash Equivalents	(26,636)	8,544	(36,404)
Cash and Cash Equivalents, Beginning of Year	120,009	111,465	147,869
Cash and Cash Equivalents, End of Year	$93,373	$120,009	$111,465

Operating Activities Cash Flows: Net cash provided by operating activities was $379 million in 2006 compared to $500 million in 2005 and $339 million in 2004. The major items that contributed to the $121 million decrease in cash provided by operating activities for 2006 were:

- A reduction in accounts payable and accrued liabilities primarily due to payments for natural gas and electricity purchases and to refunds of amounts previously held on deposit that reduced cash flow by $339 million, and
- The payment of $34 million by RG&E to resolve a dispute with Niagara Mohawk. (See RG&E Dispute Settlement Related to NMP2 Exit Agreement.)

Those decreases in cash flow were partially offset by:

- A reduction in receivables that increased cash flow by $123 million,
- A reduction in inventory due to lower natural gas prices that increased cash flow by $88 million, and
- Lower pension contributions that increased cash flow by $54 million.

The $161 million increase in cash provided by operating activities for 2005 was primarily due to:

- Increased accounts payable and accrued liabilities of $103 million primarily for the purchase of electricity and natural gas at higher prices than in the prior year.
- A decrease in the amount of taxes paid in the current year of $93 million, primarily due to taxes paid in 2004 for the sale of Ginna.
- A decrease of $35 million in customer refunds related to the proceeds from the sale of Ginna in 2004. RG&E refunded $60 million in 2004 and $25 million in 2005.

Those increases in cash flow were partially offset by:

- Increased expenditures of $40 million to replenish natural gas inventories,
- An increase of $37 million due to higher accounts receivable resulting from higher prices, and
- An increase of $35 million in pension contributions.

Investing Activities Cash Flows: Net cash used in investing activities was $228 million in 2006 compared to $368 million in 2005 and net cash provided by investing activities of $97 million in 2004. The $140 million decrease in 2006 was primarily due to the liquidation of current investments available for sale. The $465 million change in 2005 was primarily due to effects of the sale of Ginna in 2004.

Utility capital spending totaled $408 million in 2006, $331 million in 2005 and $299 million in 2004, including nuclear fuel for RG&E in 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, new customer care systems for NYSEG and RGE, and the RG&E transmission project.

Utility capital spending is projected to be $496 million in 2007, the majority of which is expected to be paid for with internally generated funds and will be primarily for the same purposes described above, except for the now completed customer care systems for NYSEG and RG&E. (See Item 8 - Note 9 to our Consolidated Financial Statements.)

Cash flows from investing activities include proceeds from the liquidation of auction rate securities, which are recorded as current investments available for sale. We use auction rate securities in a manner similar to cash equivalents and the amount invested in such securities will increase as short-term funds are available. Our investments in auction rate securities have decreased during the year as a result of the operational activities discussed above.

Financing Activities Cash Flows: Net cash used in financing activities was $178 million in 2006 compared to $123 million in 2005 and $472 million in 2004. The $55 million increase in 2006 was primarily due to lower net issuance of long-term debt securities than in 2005. The $349 million decrease in 2005 was primarily the result of lower debt redemptions than in 2004 when funds were available from the sale of Ginna.

Capital Structure at December 31,	**2006**	**2005**	**2004**
Long-term debt(1)	**57.1%**	57.0%	57.2%
Short-term debt(2)	**1.6%**	1.7%	3.1%
Preferred stock	**0.3%**	0.4%	0.7%
Common equity	**41.0%**	40.9%	39.0%
	100.0%	100.0%	100.0%

(1) Includes current portion of long-term debt

(2) Includes notes payable

The financing activities discussed below include those activities necessary for the company and its principal subsidiaries to maintain adequate liquidity and improve credit quality and ensure access to capital markets. Activities include minimal common stock issuances in connection with our Investor Services Program and employee stock-based compensation plans, new short-term facilities and various medium-term and long-term debt transactions.

Our equity financing activities during 2006 and early 2007 included:

- Raising our common stock dividend 3.4% in October 2006 to a new annual rate of $1.20 per share.
- Repurchasing 250,000 shares of our common stock in February 2006, primarily for grants of restricted stock.
- Awarding 273,733 shares of our common stock in 2006, issued out of treasury stock, to certain employees through our Restricted Stock Plan, at a weighted-average grant date fair value of $24.75 per share of common stock awarded.
- Issuing 204,235 shares of our common stock in 2006, at an average price of $24.21 per share, through our Investor Services Program. The shares were original issue shares.
- Repurchasing 350,000 shares of our common stock in January 2007, primarily for grants of restricted stock.
- Awarding 296,145 shares of our common stock in February 2007, issued out of treasury stock, to certain employees through our Restricted Stock Plan, at a weighted-average grant date fair value of $24.76 per share of common stock awarded.

In January 2006 CMP issued $10 million of Series F medium-term notes at 5.27%, due in 2016, and $30 million of Series F medium-term notes at 5.30%, due in 2016, to refinance maturing debt.

In April 2006 NYSEG issued $12 million of Series 2006A tax-exempt multi-mode bonds, due in 2024 at an initial interest rate of 3.10%, which is presently reset weekly in an auction process, to refinance $12 million of maturing debt that had an interest rate of 6%.

Energy East Corporation

In July 2006, we redeemed all of our 8 1/4% junior subordinated debt securities at par and expensed approximately $11 million of unamortized expense in July 2006 in connection with the redemption. $10 million of this amount was related to the issuance of the associated trust preferred securities. The redemption was financed by the issuance of $250 million of unsecured long-term debt at 6.75%, due in 2036, and by the issuance of short-term debt. (See Item 8 - Note 6 to our Consolidated Financial Statements.) We settled the hedges we had entered into in connection with the refinancing at a gain of approximately $15 million, which we will amortize over the life of the new debt.

In August 2006, we issued an additional $250 million of unsecured long-term debt at 6.75%, due in 2036. We used substantially all of the proceeds to redeem $232 million of 5.75% notes that were scheduled to mature in November 2006. We settled the hedges we had entered into in connection with the refinancing at a gain of approximately $8 million, which we will amortize over the life of the new debt.

In December 2006 NYSEG issued $100 million of senior unsecured notes at 5.65%, due in 2016. A portion of the proceeds was used to refund short-term debt that was issued to refinance a $25 million tax-exempt note that matured on December 1, 2006, and to fund the $77 million customer refund that will be made by the end of April 2007.

Available Sources of Funding

Energy East is the sole borrower in a revolving credit facility providing maximum borrowings of up to $300 million. Our operating utilities are joint borrowers in a revolving credit facility providing maximum borrowings of up to $475 million in aggregate. Sublimits that total to the aggregate limit apply to each joint borrower and can be altered within the constraints imposed by maximum limits that apply to each joint borrower. In June 2006 we extended our two revolving credit facilities for one year. Both facilities now have expiration dates in 2011 and require fees on undrawn borrowing capacity. Two of our operating utilities have uncommitted bilateral credit agreements for a total of $10 million. The two revolving credit facilities and the two bilateral credit agreements provided for consolidated maximum borrowings of $785 million at December 31, 2006, and December 31, 2005.

We use commercial paper and drawings on our credit facilities (see above) to finance working capital needs, to temporarily finance certain refundings and for other corporate purposes. There was $109 million of such short-term debt outstanding at December 31, 2006, and $121 million outstanding at December 31, 2005. The weighted-average interest rate on short-term debt was 6.0% at December 31, 2006, and 4.6% at December 31, 2005.

We filed a shelf registration statement with the SEC in June 2003 to sell up to $1 billion in an unspecified combination of debt, preferred stock, common stock and trust preferred securities. We plan to use the net proceeds from the sale of securities under this shelf registration, if any, for general corporate purposes. We currently have $305 million available under the shelf registration statement.

<u>Management's Discussion and Analysis of Financial Condition and Results of</u>

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 our 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. We handle market risks in accordance with established policies, which may include various offsetting, nonspeculative derivative transactions. (See Item 8 - Note 1 to our Consolidated Financial Statements.)

The financial instruments we hold or issue are not for trading or speculative purposes. Our quantitative and qualitative disclosures below relate to the following market risk exposure categories: Interest Rate Risk, Commodity Price Risk and Other Market Risk.

Interest Rate Risk: We are exposed to risk resulting from interest rate changes on variable-rate debt and commercial paper. We use interest rate swap agreements to manage the risk of increases in variable interest rates and to maintain desired fixed-to-floating rate ratios. We record amounts paid and received under those agreements as adjustments to the interest expense of the specific debt issues. After giving effect to those agreements we estimate that, at December 31, 2006, a 1% change in average interest rates would change our annual interest expense for variable-rate debt by about $5 million. Pursuant to its current rate plans, RG&E defers any changes in variable-rate interest expense. (See Item 8 - Notes 6, 7 and 11 to our Consolidated Financial Statements and Notes 5, 6 and 10 to RG&E's Financial Statements.)

We also use derivative instruments to mitigate risk resulting from interest rate changes on anticipated future financings, and amortize amounts paid and received under those instruments to interest expense over the life of the corresponding financing.

Commodity Price Risk: Commodity price risk, due to volatility experienced in the wholesale energy markets, is a significant issue for the electric and natural gas utility industries. We manage this risk through a combination of regulatory mechanisms, such as allowing for the pass-through of the market price of electricity and natural gas to customers, and through comprehensive risk management processes. These measures mitigate our commodity price exposure, but do not completely eliminate it.

NYSEG and RG&E offer their retail customers choice in their electricity supply including fixed and variable rate options and an option to purchase electricity supply from an ESCO. During the fourth quarter of 2006, NYSEG's and RG&E's electric customers chose their supply options for 2007. The table below shows the percentages of load that are projected to be served under the various commodity supply options for 2007.

	NYSEG	RG&E
Fixed Price Option	17%	21%

Variable Price Option	45%	29%
Energy Service Company Option	38%	50%

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

Energy East Corporation

NYSEG's and 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 effectively combines delivery and supply service at a fixed price. NYSEG and RG&E use electricity contracts, both physical and financial, to manage fluctuations in the cost of electricity required to serve customers who select the fixed rate option. We include the cost or benefit of those contracts in the amount expensed for electricity purchased when the related electricity is sold. Owned electric generation and long-term supply contracts reduce NYSEG's exposure, and significantly reduce RG&E's exposure, to market fluctuations for procurement of their fixed rate option electricity supply.

As of February 15, 2007, the portion of expected load for fixed rate option customers not supplied by owned generation or long-term contracts is 100% hedged for NYSEG for on-peak and off-peak periods in 2007. A fluctuation of $1.00 per megawatt-hour in the average price of electricity would change NYSEG's earnings less than $150 thousand for NYSEG in 2007. RG&E expects to meet its fixed price load obligations in 2007 with owned generation or long-term supply contracts. The percentage of NYSEG's and RG&E's hedged load is based on 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.

Other comprehensive income associated with our financial electricity contracts for the year ended December 31, 2006, was $7 million, reflecting a decrease of $162 million as compared to December 31, 2005. The decrease is primarily a result of wholesale market price changes for electricity and the settlement of positions in 2006. Other comprehensive income for 2006 will have no effect on future net income because we only use financial electricity contracts to hedge the price of our electric load requirements for customers who have chosen a fixed price option.

All of our 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. We use natural gas futures and forwards to manage fluctuations in natural gas commodity prices in order to provide price stability to customers. We include the cost or benefit of natural gas futures and forwards in the commodity cost that is passed on to customers when the related sales commitments are fulfilled. We record changes in the fair value of natural gas hedge contracts as regulatory assets or regulatory liabilities.

Energetix and NYSEG Solutions offer retail electric and natural gas service to customers in New York State and actively hedge the load required to serve customers that have chosen them as their commodity supplier. As of February 15, 2007, the energy marketing subsidiaries expected fixed price load was 100% hedged for 2007. A fluctuation of $1.00 per megawatt-hour in the average price of electricity would change earnings less than $20,000 in 2007. The percentage of hedged load for the energy marketing subsidiaries is based on 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.

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

Energy East Corporation

NYSEG, RG&E, Energetix and NYSEG Solutions face risks related to counterparty performance on hedging contracts due to counterparty credit default. We have developed a matrix of unsecured credit thresholds that are dependent on a counterparty's Moody's or S&P credit rating. When our exposure to risk for a counterparty exceeds the unsecured credit threshold, the counterparty is required to post additional collateral or we will no longer transact with the counterparty until the exposure drops below the unsecured credit threshold.

Other Market Risk: Our pension plan assets are primarily made up of equity and fixed income investments. Fluctuations in those markets as well as changes in interest rates may cause us to recognize increased or decreased pension income or expense. Our pension income would change by approximately $7 million if our expected return on plan assets were to change by 1/4% and by approximately $6 million if our discount rate were to change by 1/4%. Under RG&E's Electric and Natural Gas Rate Agreements and under NYSEG's natural gas rate plan, we defer changes in pension income resulting from changes in market conditions. (See Item 8 - Note 14 to our Consolidated Financial Statements and Note 12 to RG&E's Financial Statements.)

Results of Operations

Earnings per Share

(Thousands, except per share amounts)	2006	2005	2004
Income from Continuing Operations	**$259,832**	$256,833	$237,621
Net Income	**$259,832**	$256,833	$229,337
Average Common Shares Outstanding, basic	**146,962**	146,964	146,305
Earnings per Share from Continuing Operations, basic	**$1.77**	$1.75	$1.63
Earnings per Share, basic	**$1.77**	$1.75	$1.57

Comparing 2006 to 2005: Earnings per share from continuing operations, basic for 2006 increased two cents compared to 2005. The major increases in earnings per share were:

- 18 cents due to higher margins on electricity sales, primarily reflecting lower accruals under various earnings-sharing mechanisms,

- 7 cents in lower income tax expense reflecting variances in recurring flow-through items, differences in the 2005 filed tax return compared to the 2005 book tax expense and settlement of an audit of our 2002 and 2003 federal income tax returns,
- 4 cents resulting from the environmental insurance settlements in the fourth quarter of 2006,
- 5 cents due to the termination of SGF's operations in 2005, including 4 cents from the writedown of the assets, and
- 2 cents due to reductions in various operating and maintenance expenses.

Those increases were partially offset by decreases in earnings per share of:

- 11 cents resulting from higher storm and flood costs,
- 7 cents resulting from higher bad debt expense, including 4 cents for amounts that were previously deferred and began to be recovered as part of a rate increase for SCG effective January 1, 2006,
- 6 cents for higher interest expense resulting from higher rates on short-term and variable rate debt, and higher carrying costs on regulatory liabilities,
- 5 cents for the recognition of unamortized expense resulting from the redemption of our 8 1/4% junior subordinated debt securities and associated trust preferred securities in July 2006,
- 4 cents in increased depreciation expense, due to placing NYSEG's customer care system into service in the first quarter of 2006,
- 2 cents from lower margins on natural gas sales due to warmer weather. This amount would have been higher except for the SCG rate increase effective January 1, 2006, and the effect of weather normalization mechanisms.

Comparing 2005 to 2004: Earnings from continuing operations, basic for 2005 increased 12 cents per share compared to 2004. The major increases in earnings per share were:

- 21 cents due to higher margins on electric sales under electric commodity programs for New York customers,
- 17 cents resulting from a 3% increase in electric deliveries, and
- 4 cents resulting from increased natural gas margins. The increase resulted primarily from increased sales to interruptible customers and RG&E's adoption of a natural gas merchant function charge in 2004.

Those increases were partially offset by decreases in earnings per share of:

- 19 cents per share resulting from higher operating and maintenance expenses, including approximately 5 cents for storm-related repairs and maintenance, 9 cents for increases in allowances for doubtful accounts, 2 cents for higher regional network services transmission costs and 4 cents for medical and other benefits costs. The higher operating and maintenance expenses were partially offset by a decrease of 8 cents for lower stock option expenses. Stock option expense in 2005 included a one cent-per-share charge for the adoption of Statement 123(R),

- 4 cents per share from the termination of SGF's operations and the writedown of assets, and
- 7 cents for the one-time effects from the sale of Ginna and the approval of RG&E's Electric and Natural Gas Rate Agreements that increased earnings in 2004. The one-time effects included the flow-through of excess deferred taxes and ITCs and the elimination of certain reserves established pending regulatory treatment.

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

Energy East Corporation

Energy Delivery

Revenues for our utility operating companies are highly dependent upon the volume of deliveries of electricity and natural gas. We have regulatory mechanisms in place to provide recovery of certain costs, including stranded costs and natural gas purchase costs, independent of sales volume, and some of our natural gas companies have weather normalization clauses that mitigate the effect of delivery volume changes due to weather. Changes in delivery volume can nevertheless have a significant effect on our results of operations, financial position and cash flows.

Electric revenues are also dependent upon the volume of sales of electricity to retail customers under Voice Your Choice commodity programs offered by our New York utilities. The cost of the electricity sold to retail customers is either recovered as a passthrough or hedged to substantially eliminate the risk of price volatility. Changes in commodity sales volume, however, can have a significant effect on our results of operations and cash flows.

Percentage increases (decreases) in energy delivery volumes and electric commodity sales volumes compared to the prior year are:

	Electricity Deliveries		Natural Gas Deliveries	
	2006	**2005**	**2006**	**2005**
(Thousands)				
Residential	**(4%)**	6%	**(12%)**	(3%)
Commercial	**(2%)**	3%	**(11%)**	1%
Industrial	**(3%)**	(2%)	**(11%)**	(3%)
Other	**(2%)**	2%	**17%**	(2%)
Transportation of customer-owned natural gas	**NA**	NA	**(7%)**	(1%)
Total Retail	**(3%)**	3%	**(8%)**	(2%)
Wholesale	**(2%)**	21%	**(87%)**	(45%)
Total Deliveries	**(2%)**	7%	**(8%)**	(2%)
Electricity commodity sales	**(7%)**	(8%)	**NA**	NA

NA - not applicable

Several factors influence the volume of energy deliveries. The major factor is weather. In 2006 winter temperatures were significantly warmer than normal. The effects of warmer or colder winter weather are especially significant for our natural gas companies. We estimate that for 2006, 2% of the 3% decline in retail electricity deliveries and 6% of the 8% decline in retail natural gas deliveries was the result of warmer winter weather. Weather conditions for New York and New England for the past three years are summarized below.

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

Energy East Corporation

Weather Conditions

	2006	2005	2004	Normal
New York				
Heating-degree days	**5,991**	6,870	6,983	6,974
(Warmer) colder than prior year	**(13%)**	(2%)		
(Warmer) colder than normal	**(14%)**	(2%)		
Cooling-degree days	**562**	748	324	493
(Cooler) warmer than prior year	**(25%)**	131%		
(Cooler) warmer than normal	**14%**	52%		
New England				
Heating-degree days	**5,447**	6,229	6,260	6,315
(Warmer) colder than prior year	**(13%)**	(1%)		
(Warmer) colder than normal	**(14%)**	(1%)		
Cooling-degree days	**444**	506	250	388
(Cooler) warmer than prior year	**(12%)**	102%		
(Cooler) warmer than normal	**14%**	30%		

Operating Results for the Electric Delivery Business

	2006	2005	2004
(Thousands)			
Operating Revenues			
Retail	**$2,254,003**	$2,250,105	$2,191,500
Wholesale	**554,300**	568,746	402,122
Other	**214,734**	150,707	187,700
Total Operating Revenues	**3,023,037**	2,969,558	$2,781,322
Operating Expenses			
Electricity purchased and fuel used in generation	**1,467,068**	1,457,746	1,321,081
Other operating and maintenance expenses	**715,219**	672,595	667,503
Depreciation and amortization	**187,587**	178,806	196,782
Other taxes	**148,589**	143,359	154,038
Gain on sale of generation assets	-	-	(340,739)
Deferral of asset sale gain	-	-	228,785
Total Operating Expenses	**2,518,463**	2,452,506	2,227,450

Operating Income	**$504,574**	$517,052	$553,872

Operating Revenues: The $53 million increase in operating revenues for 2006 was primarily the result of:

- An increase of $57 million due to higher commodity prices for retail electric energy sold by NYSEG and RG&E under various commodity options where they provide supply,
- An increase of $60 million in average delivery prices resulting from a transmission rate increase at CMP and higher transition charges for NYSEG and RG&E,
- An increase of $53 million resulting from lower accruals for earnings sharing including $14 million in the first quarter of 2006 for the finalization of actual earnings-sharing amounts for 2005 per NYSEG's and RG&E's annual compliance filings, and
- An increase of $31 million in other revenues primarily for accruals to recover actual purchase power costs, including $25 million for higher Ginna-related costs.

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Those increases were partially offset by:

- A decrease of $78 million resulting from a 7% reduction in sales volume under the New York utilities' Voice Your Choice commodity programs where they provide supply,
- A decrease of $22 million in wholesale sales resulting from a 2% decline in wholesale volume,
- A decrease of $12 million in other revenue including $6 million related to a NUG incentive at CMP and $6 million of accruals for transmission congestion costs, both recorded in 2005, and
- A decrease of $35 million resulting from a 3% decline in retail deliveries, about 2% of which was caused by cooler summer temperatures and warmer winter weather. Heating degree days declined 13% in 2006. The other 1% of the decline was largely attributable to the expiration of a major NUG contract for CMP, since the NUG is now using electricity previously sold to CMP to meet its own load requirements.

The $188 million increase in operating revenues for 2005 was primarily the result of:

- An increase of $73 million from increases in market prices for electric energy sold by NYSEG and RG&E under commodity options where they provide supply,
- An increase of $168 million in wholesale revenues, which included $100 million from increased wholesale sales by NYSEG and RG&E, $29 million from higher prices on those sales and $39 million as a result of higher prices on the sale of CMP's NUG entitlements, effective March 1, 2005,
- An increase of $42 million resulting from a 3% increase in retail deliveries. About half of this increase resulted from warmer summer weather and the remainder resulted from general economic conditions, and
- An increase of $36 million in other electric revenues, including $6 million from CMP's NUG contract restructuring incentive and the remainder primarily from accruals to reflect

actual generating and purchase power costs.

Those increases were partially offset by:

- A decrease of $102 million resulting from lower transition charges. The transition charge reflects the difference between the market price of electricity and the prices set by our long-term electricity supply contracts, and decreases as market prices increase, and
- A decrease of $28 million as a result of higher accruals for earnings sharing under NYSEG's and RG&E's electric rate plan provisions.

Operating Expenses: The $66 million increase in operating expenses for 2006 was primarily the result of:

- An increase of $9 million in purchased power costs resulting from a $39 million increase for higher wholesale electricity market prices, and $25 million for higher purchased power costs for RG&E related to Ginna purchases, partially offset by a $55 million decrease due to the expiration of a major NUG contract in 2006,
- An increase of $43 million in operating and maintenance costs, including $26 million for storm restoration, $9 million for a write-off resulting from the August 2006 NYSEG rate decision and $9 million for higher bad debt expense,
- An increase of $9 million in depreciation resulting largely from NYSEG's new customer care system, and
- An increase of $5 million in other taxes.

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

Energy East Corporation

The $225 million increase in operating expenses for 2005 was primarily the result of:

- An increase of $112 million as a result of the regulatory treatment in 2004 of RG&E's gain on the sale of Ginna, which included RG&E's recognition of a $341 million pretax gain partially offset by the after-tax deferral of the gain of $229 million,
- A net increase of $1 million in operating expenses as a result of the sale of Ginna, reflecting an increase in purchased power costs of $63 million, substantially offset by decreases of $37 million in other operating and maintenance expenses, $21 million in depreciation and $4 million in other taxes,

- An increase of $75 million in power purchases largely resulting from increased wholesale sales and higher market prices for electric supply purchased for the New York electric commodity customers,
- An increase of $10 million due to certain credits to other operating expenses that resulted from RG&E's Electric Rate Agreement and reduced expenses in 2004, and

- Increases in various other operating and maintenance expenses, excluding Ginna, totaling $27 million. Higher storm costs accounted for approximately $11 million of that increase, higher transmission-related expenses accounted for an additional $6 million, higher uncollectible expense accounted for $9 million and increased medical and other benefits accounted for $8 million. Lower stock option expense reduced electric operating expenses by $10 million.

Operating Results for the Natural Gas Delivery Business

	2006	**2005**	**2004**
(Thousands)			
Operating Revenues			
Retail	**$1,676,525**	$1,764,235	$1,534,900
Wholesale	**563**	643	182
Other	**20,513**	18,669	14,068
Total Operating Revenues	**1,697,601**	1,783,547	1,549,150
Operating Expenses			
Natural gas purchased	**1,079,980**	1,161,059	952,806
Other operating and maintenance expenses	**246,727**	246,339	231,182
Depreciation and amortization	**86,728**	85,050	88,998
Other taxes	**95,390**	98,589	93,500
Total Operating Expenses	**1,508,825**	1,591,037	1,366,486
Operating Income	**$188,776**	$192,510	$182,664

Operating Revenues: The $86 million decrease in operating revenues for 2006 was primarily the result of:

- A decrease of $146 million as a result of a 9% decrease in delivery volumes excluding transportation, largely due to warmer winter weather and customer conservation. Heating degree days in 2006 declined 13% compared to 2005 and caused approximately two-thirds of the sales decline.

That decrease was partially offset by:

- An increase of $24 million primarily as a result of higher market prices for natural gas that were passed on to customers,
- An increase of $20 million due to higher base rates for SCG effective January 1, 2006, and
- An increase of $16 million resulting from weather normalization mechanisms.

The $234 million increase in operating revenues for 2005 was primarily the result of:

- An increase of $244 million as a result of higher prices of purchased natural gas that were passed on to customers, and
- An increase of $23 million in other natural gas revenues resulting primarily from higher

interruptible sales.

Those increases were partially offset by:

- Lower retail deliveries of $33 million due in part to warmer weather but also reflecting economic conditions including higher market prices for natural gas.

Operating Expenses: The $82 million decrease in operating expenses for 2006 was primarily the result of:

- A reduction of $100 million due to lower volumes of natural gas sold, and
- Reductions in various operating and maintenance expense items totaling $9 million.

Those decreases were partially offset by:

- An increase of $18 million due to higher market prices for purchased natural gas, and
- An increase of $8 million in bad debt expense, primarily resulting from amounts that were previously deferred and began to be recovered as part of SCG's rate increase effective January 1, 2006.

The $225 million increase in operating expenses for 2005 was primarily the result of:

- An increase of $209 million for purchased gas costs, resulting from an increase of $241 million due to higher prices offset by $32 million for lower volumes, and
- An increase of $15 million in other operating and maintenance costs, including $12 million related to an increase in the allowance for doubtful accounts.

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

Energy East Corporation

Operating Results for the Energy Marketing Business

The primary business included in our Other segment is our energy marketing business comprised of Energetix, Inc. and NYSEG Solutions, Inc., which market electricity and natural gas to customers throughout the state of New York. They currently have 132,000 electricity customers and 42,000 natural gas customers in the service territories of RG&E, NYSEG and several other New York state utilities. Sales and revenues for these companies have become more significant in recent years as changes in the regulatory environment in New York have fostered the development of competitive energy suppliers.

	2006	2005	2004
(Thousands)			
Electricity sales (MWh)	**4,516**	5,025	4,541

Natural gas sales (Dth)	**7,309**	10,605	11,194
Operating Revenues			
Electric	**$316,221**	$409,473	$272,268
Natural gas	**81,239**	109,608	91,478
Total Operating Revenues	**397,460**	519,081	363,746
Operating Expenses			
Electricity purchased	**300,053**	397,251	261,512
Natural gas purchased	**75,489**	101,073	82,767
Other operating expenses	**12,598**	13,560	11,419
Total Operating Expenses	**388,140**	511,884	355,698
Operating Income	**$9,320**	$7,197	$8,048

Operating Revenues: The $122 million decrease in operating revenues for 2006 was primarily the result of:

- A decrease of $41 million due to decreased sales volume for electricity due warmer winter weather and cooler summer weather.
- A decrease of $34 million due to decreased sales volume for natural gas due to a significant reduction in heating degree days, and
- A decrease of $52 million due to lower prices for electricity.

Those decreases were partially offset by an increase of $6 million for higher prices for natural gas.

The $155 million increase in operating revenues for 2005 was primarily the result of:

- An increase of $29 million due to increased sales volume for electricity due to customers being added as a result of NYSEG's and RG&E's Voice Your Choice programs.
- An increase of $108 million due to higher prices for electricity, and
- An increase of $23 million due to higher prices for natural gas.

Those increases were offset by a decrease of $5 million due to decreased sales volume for natural gas.

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

Energy East Corporation

Operating Expenses: The $124 million decrease in operating expense for 2006 was primarily the result of:

- A decrease of $40 million in purchased electricity due to decreased sales volume,
- A decrease of $31 million in purchased natural gas due to decreased sales volume, and
- A decrease of $57 million in purchased electricity due to lower prices.

Those decreases were partially offset by an increase of $6 million in purchased natural gas due to higher prices.

The $156 million increase in operating expenses for 2005 was primarily the result of:

- An increase of $29 million in purchased electricity due to increased sales volume,
- An increase of $108 million in purchased electricity due to higher prices, and
- An increase of $23 million in purchased natural gas due to higher prices.

Those increases were partially offset by a decrease of $4 million in purchased natural gas due to decreased sales volume.

Other Items

	2006	**2005**	**2004**
(Thousands)			
Other (Income)	**$(46,126)**	$(32,904)	$(35,497)
Other Deductions	**$24,578**	$8,858	$15,803
Interest Charges, net	**$308,824**	$288,897	$276,890
Income Taxes on Continuing Operations	**$155,255**	$169,997	$251,445

Other (Income) and Other Deductions: (See Item 8 - Note 1 to our Consolidated Financial Statements.)

The changes for 2006 include:

- An $8 million increase in Other (income) from environmental insurance settlements,
- A $4 million increase in Other (income) from higher gains on risk management activity,
- An $11 million increase in Other deductions for the recognition of unamortized expense resulting from the redemption of our 8 1/4% junior subordinated debt securities and the associated trust preferred securities in July 2006, and
- A $6 million increase in Other deductions from higher losses on risk management contracts.

The changes for 2005 include:

- A $3 million increase in Other (income) from interest income,
- A $6 million decrease in Other (income) due to the effect of a one-time increase as a result of the RG&E Electric Rate Agreement in 2004,
- A $6 million decrease in Other deductions for lower losses on hedge activity related to risk management contracts,
- A $3 million decrease in Other deductions for losses from the disposition of nonutility property, and
- A $4 million increase in Other deductions from miscellaneous losses.