Part III

Item 13.

Certain Relationships *and* Related Transactions

Item 14.

Principal Accountant Fees *and* Services

Part IV

Item 15.

Exhibits *and* Financial Statement Schedules

(a) The following documents are filed as a part of this report:

2. Financial Statement Schedules:

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the financial statements or the notes to consolidated financial statements.

(b) Exhibits

See Index to Exhibits at page 76 for a description of the exhibits filed as a part of this report. Documents filed prior to June 1, 2001, were filed with the Securities and Exchange Commission under our prior name, Cross Timbers Oil Company.

XTO ENERGY INC. CONSOLIDATED BALANCE SHEETS

(in millions, except shares)	December 31 2006	December 31 2005
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 5	$ 2
Accounts receivable, net	656	644
Derivative fair value	804	193
Current income tax receivable	66	35
Other	54	69
Total Current Assets	1,585	943
Property and Equipment, at cost – successful efforts method:		
Proved properties	12,369	9,979
Unproved properties	414	283
Other	799	278
Total Property and Equipment	13,582	10,540
Accumulated depreciation, depletion and amortization	(2,758)	(2,032)
Net Property and Equipment	10,824	8,508
Derivative fair value	56	1
Acquired gas gathering contracts, net of amortization	121	132
Goodwill	215	213
Other	84	60
Total Other Assets	476	406
TOTAL ASSETS	$ 12,885	$ 9,857
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 912	$ 739
Payable to royalty trusts	23	13
Derivative fair value	37	90
Deferred income tax payable	263	38
Other	5	4
Total Current Liabilities	1,240	884
Long-term Debt	3,451	3,109
Other Long-term Liabilities:		
Derivative fair value	1	–
Deferred income taxes payable	1,978	1,390
Asset retirement obligation	303	219
Other	47	46
Total Other Long-term Liabilities	2,329	1,655
Commitments and Contingencies (Note 6)		
Stockholders' Equity:		
Common stock ($0.01 par value, 1,000,000,000 shares authorized, 371,473,935 and 365,220,597 shares issued)	4	4
Additional paid-in capital	2,058	1,865
Treasury stock, at cost (3,919,872 and 1,655,413 shares)	(125)	(39)
Retained earnings	3,442	2,311
Accumulated other comprehensive income	486	68
Total Stockholders' Equity	5,865	4,209
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 12,885	$ 9,857

See accompanying notes to consolidated financial statements.

XTO ENERGY INC. Consolidated Income Statements

(in millions, except per share data)	Year Ended December 31 2006	2005	2004
REVENUES			
Gas and natural gas liquids	$ 3,490	$ 2,787	$ 1,613
Oil and condensate	1,002	670	319
Gas gathering, processing and marketing	86	56	18
Other	(2)	6	(2)
Total Revenues	4,576	3,519	1,948
EXPENSES			
Production	491	406	246
Taxes, transportation and other	372	306	174
Exploration	22	24	11
Depreciation, depletion and amortization	875	655	407
Accretion of discount in asset retirement obligation	16	12	8
Gas gathering and processing	41	11	6
General and administrative	189	155	165
Derivative fair value (gain) loss	(102)	(13)	12
Total Expenses	1,904	1,556	1,029
OPERATING INCOME	2,672	1,963	919
OTHER (INCOME) EXPENSE			
Gain on distribution of royalty trust units	(469)	–	–
Interest expense, net	180	153	93
Total Other (Income) Expense	(289)	153	93
INCOME BEFORE INCOME TAX	2,961	1,810	826
INCOME TAX EXPENSE	1,101	658	318
NET INCOME	$ 1,860	$ 1,152	$ 508
EARNINGS PER COMMON SHARE			
Basic	$ 5.10	$ 3.21	$ 1.53
Diluted	$ 5.03	$ 3.15	$ 1.51
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING	364.8	358.4	332.9

See accompanying notes to consolidated financial statements.

XTO ENERGY INC. CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	Year Ended December 31 2006	2005	2004
OPERATING ACTIVITIES			
Net income	$ 1,860	$ 1,152	$ 508
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	875	655	407
Accretion of discount in asset retirement obligation	16	12	8
Non-cash incentive compensation	63	34	67
Dry hole expense	9	–	–
Deferred income tax	529	415	255
Gain on distribution of royalty trust units	(469)	–	–
Non-cash derivative fair value (gain) loss	(39)	(39)	6
Other non-cash items	10	23	24
Changes in operating assets and liabilities, net of effects of acquisitions of corporations (a)	5	(158)	(58)
Cash Provided by Operating Activities	2,859	2,094	1,217
INVESTING ACTIVITIES			
Proceeds from sale of property and equipment	6	17	25
Property acquisitions, including acquisitions of corporations	(616)	(1,407)	(1,905)
Development costs, capitalized exploration costs and dry hole expense	(2,047)	(1,304)	(523)
Other property and asset additions	(379)	(214)	(115)
Cash Used by Investing Activities	(3,036)	(2,908)	(2,518)
FINANCING ACTIVITIES			
Proceeds from long-term debt	5,719	3,825	3,884
Payments on long-term debt	(5,377)	(2,977)	(3,093)
Net proceeds from common stock offering	–	–	580
Dividends	(109)	(67)	(20)
Senior note and debt offering costs	(9)	(5)	(14)
Proceeds from exercise of stock options and warrants	24	73	8
Payments upon exercise of stock options	(46)	(20)	(13)
Excess tax benefit on exercise of stock options	50	–	–
Purchases of treasury stock and other	(72)	(23)	(28)
Cash Provided by Financing Activities	180	806	1,304
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	3	(8)	3
Cash and Cash Equivalents, January 1	2	10	7
Cash and Cash Equivalents, December 31	$ 5	$ 2	$ 10
(a) **Changes in Operating Assets and Liabilities**			
Accounts receivable	$ (12)	$ (258)	$ (132)
Other current assets	(16)	(47)	(40)
Other operating assets and liabilities	(12)	(3)	4
Current liabilities	45	150	110
	$ 5	$ (158)	$ (58)

See accompanying notes to consolidated financial statements.

XTO ENERGY INC. CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(in millions, except per share amounts)	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balances, December 31, 2003	$ 3	$ 753	$ –	$ 763	$ (53)	$ 1,466
Net income	–	–	–	508	–	508
Change in hedge derivative fair value, net of applicable income tax of $51	–	–	–	–	(85)	(85)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of applicable income tax of $64	–	–	–	–	109	109
Comprehensive income						532
Issuance/vesting of performance shares	–	64	(24)	–	–	40
Stock option exercises, including income tax benefits	–	13	–	–	–	13
Treasury stock purchases	–	–	(1)	–	–	(1)
Common stock offering	–	580	–	–	–	580
Common stock dividends ($0.09 per share)	–	–		(31)	–	(31)
Balances, December 31, 2004	3	1,410	(25)	1,240	(29)	2,599
Net income	–	–	–	1,152	–	1,152
Change in hedge derivative fair value, net of applicable income tax of $27	–	–	–	–	(48)	(48)
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of applicable income tax of $81	–	–	–	–	145	145
Comprehensive income						1,249
Issuance/vesting of performance shares	–	33	(14)	–	–	19
Stock option exercises, including income tax benefits	–	75	–	–	–	75
Issuance of common stock and warrants for acquisition of corporation	1	347	–	–	–	348
Common stock dividends ($0.225 per share)	–	–	–	(81)	–	(81)
Balances, December 31, 2005	4	1,865	(39)	2,311	68	4,209
Net income	–	–	–	1,860	–	1,860
Change in hedge derivative fair value, net of applicable income tax of $473	–	–	–	–	810	810
Hedge derivative contract settlements reclassified into earnings from accumulated other comprehensive income, net of applicable income tax of $225	–	–	–	–	(390)	(390)
Adjustment related to initial recognition of funded status of post-retirement health plan, net of applicable income tax of $1	–	–	–	–	(2)	(2)
Comprehensive income						2,278
Issuance/vesting of stock awards	–	10	(3)	–	–	7
Expensing of stock options	–	53	–	–	–	53
Stock option and warrant exercises, including income tax benefits	–	28	–	–	–	28
Treasury stock purchases	–	–	(83)	–	–	(83)
Issuance of common stock for acquisition of corporation	–	102	–	–	–	102
Fair value of royalty trust unit distribution ($1.687 per share)	–	–	–	(614)	–	(614)
Common stock dividends ($0.315 per share)	–	–	–	(115)	–	(115)
Balances, December 31, 2006	$ 4	$ 2,058	$ (125)	$ 3,442	$ 486	$ 5,865

See accompanying notes to consolidated financial statements.

1. Organization and Summary of Significant Accounting Policies

XTO Energy Inc., a Delaware corporation, was organized under the name Cross Timbers Oil Company in October 1990 to ultimately acquire the business and properties of predecessor entities that were created from 1986 through 1989. Cross Timbers Oil Company completed its initial public offering of common stock in May 1993 and changed its name to XTO Energy Inc. in June 2001.

The accompanying consolidated financial statements include the financial statements of XTO Energy Inc. and all of its wholly owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Certain amounts presented in prior period financial statements have been reclassified for consistency with current period presentation.

All common stock shares and per share amounts in the accompanying financial statements have been adjusted for the four-for-three stock split effected on March 15, 2005 and the five-for-four stock split effected March 17, 2004.

We are an independent oil and gas company with production and exploration concentrated in the southwestern and central United States. We also gather, process and market gas, transport and market oil and conduct other activities directly related to our oil and gas producing activities.

Property and Equipment

We follow the successful efforts method of accounting, capitalizing costs of successful exploratory wells and expensing costs of unsuccessful exploratory wells. Exploratory geological and geophysical costs are expensed as incurred. All developmental costs are capitalized. We generally pursue acquisition and development of proved reserves as opposed to exploration activities. A significant portion of the property costs reflected in the accompanying consolidated balance sheets are from acquisitions of proved properties from other oil and gas companies. Proved properties balances include costs of $713 million at December 31, 2006 and $472 million at December 31, 2005 related to wells in process of drilling. Drill well costs are transferred to proved properties generally within one month of the well completion date. As of December 31, 2006, capitalized costs totaled approximately $8 million for three exploratory wells completed more than one year ago and pending completion of pipelines to the well site. These exploratory wells are expected to be transferred to proved properties during the first quarter of 2007. Inventory held for future use on our producing properties totaled $37 million at December 31, 2006 and $53 million at December 31, 2005, and is included in other current assets on the consolidated balance sheet.

Depreciation, depletion and amortization of proved producing properties is computed on the unit-of-production method based on estimated proved oil and gas reserves. Other property and equipment is generally depreciated using either the unit-of-production method for assets associated with specific reserves or the straight-line method over estimated useful lives which range from 3 to 40 years. Repairs and maintenance are expensed, while renewals and betterments are generally capitalized.

If conditions indicate that long-term assets may be impaired, the carrying value of property is compared to management's future estimated pre-tax cash flow from properties generally aggregated on a field-level basis. If impairment is necessary, the asset carrying value is written down to fair value. Cash flow pricing estimates are based on existing proved reserve and production information and pricing assumptions that management believes are reasonable. Impairment of individually significant unproved properties is assessed on a property-by-property basis, and impairment of other unproved properties is assessed and amortized on an aggregate basis.

In December 2004, the Financial Accounting Standards Board issued SFAS No. 153, *Exchanges of Nonmonetary Assets, an Amendment of APB Opinion No. 29,* which provides that all nonmonetary asset exchanges that have commercial substance must be measured based on the fair value of the assets exchanged, and any resulting gain or loss recorded. An exchange is defined as having commercial substance if it results in a significant change in expected future cash flows. Exchanges of operating interests by oil and gas producing companies to form a joint venture continue to be exempted. APB Opinion No. 29 previously exempted exchanges of similar productive assets from fair value accounting, subject to recording an impairment loss. We adopted the provisions of SFAS No. 153 beginning July 1, 2005, and, based on the fair value of properties exchanged, we recognized a $10 million gain on the exchange of nonmonetary assets during 2005 (Note 13).

Asset Retirement Obligation

Effective January 1, 2003, we adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations.* SFAS No. 143 provides that, if the fair value for asset retirement obligation can be reasonably estimated, the liability should be recognized in the period when it is incurred. Oil and gas producing companies incur this liability upon acquiring or drilling a well. Under the method prescribed by SFAS No. 143, the retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with an offsetting increase to proved properties on the balance sheet. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement. See Note 5.

Royalty Trusts

We created Cross Timbers Royalty Trust in February 1991 and Hugoton Royalty Trust in December 1998 by conveying defined net profits interests in certain of our properties. Units of both trusts are traded on the New York Stock Exchange. We make monthly net profits payments to each trust based on revenues and costs from the related underlying properties. We owned 54.3% of Hugoton Royalty Trust, which is the portion we retained following our sale of units in 1999 and 2000. In January 2006, the Board of Directors declared a dividend to common stockholders, consisting of all 21.7 million Hugoton Royalty Trust units owned by us. The dividend ratio of 0.059609 trust units for each common share outstanding was set on the record date of April 26, 2006. The units were distributed on May 12, 2006, when this dividend was recorded. We recorded this dividend at $614 million, or approximately $1.687 per common share, the fair market value of the units based on the May 12, 2006 average high and low New York Stock Exchange trade price of $28.31. After considering the cost of the trust units, we recorded a gain on distribution of $469 million before income tax.

We announced in January 2006 that the Company would consider selling its interests in the underlying properties that are subject to the Cross Timbers Royalty Trust and Hugoton Royalty Trust net profits interests. However, in August 2006, after a full review, we announced that we will retain ownership of these underlying properties at this time.

Amounts due the trusts, net of amounts retained by our ownership of trust units, are deducted from our revenues, taxes, production expenses and development costs.

Cash and Cash Equivalents

Cash equivalents are considered to be all highly liquid investments having an original maturity of three months or less.

Income Taxes

We record deferred income tax assets and liabilities to recognize timing differences between recognition of income for financial statement and income tax reporting purposes. Deferred income tax assets are calculated using enacted tax rates applicable to taxable income in the years when we anticipate these timing differences will reverse. The effect of changes in tax rates is recognized in the period of enactment. See Note 4.

Other Assets

Other assets primarily include deferred debt costs that are amortized to interest expense over the term of the related debt (Note 3) and the long-term portion of gas balancing receivable (see *Revenue Recognition and Gas Balancing* below). Other assets are presented net of accumulated amortization of $16 million at December 31, 2006 and $19 million at December 31, 2005.

In accordance with Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets,* we have determined that a portion of the purchase price of the Antero Resources Corporation acquisition (Note 13) is allocable to gas gathering contracts and goodwill. Gas gathering contracts are associated with the pipeline acquired, and the value of $140 million has been determined based on the estimated discounted cash flows from those contracts. The gas gathering contracts are amortized, as a component of depreciation, depletion and amortization expense, on a unit-of-production basis using the estimated proved reserves of the related Barnett Shale properties. Accumulated amortization of acquired gas gathering contracts was $19 million as of December 31, 2006 and $8 million as of December 31, 2005. Amortization expense is expected to be approximately $6 million to $9 million annually from 2007 through 2011, depending on Barnett Shale production.

Goodwill of $215 million represents the excess of the purchase price paid for Antero Resources over the fair value of the assets acquired and liabilities assumed. In accordance with SFAS No. 142, goodwill is not amortized, but instead is subject to an annual assessment of impairment based on a fair value test performed in the fourth quarter.

Derivatives

We use derivatives to hedge against changes in cash flows related to product price and interest rate risks, as opposed to their use for trading purposes. SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* requires that all derivatives be recorded on the balance sheet at fair value. We generally determine the fair value of futures contracts and swap contracts based on the difference between the derivative's fixed contract price and the underlying market price at the determination date. The fair value of call options and collars are generally determined under the Black-Scholes option-pricing model. Most values are confirmed by counterparties to the derivative.

Realized and unrealized gains and losses on derivatives that are not designated as hedges, as well as on the ineffective portion of hedge derivatives, are recorded as a derivative fair value gain or loss in the income statement. Unrealized gains and losses on effective cash flow hedge derivatives, as well as any deferred gain or loss realized upon early termination of effective hedge derivatives, are recorded as a component of accumulated other comprehensive income. When the hedged transaction occurs, the realized gain or loss, as well as any deferred gain or loss, on the hedge derivative is transferred from accumulated other comprehensive income to earnings. Realized gains and losses on commodity hedge derivatives are recognized in oil and gas revenues, and realized gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Settlements of derivatives are included in cash flows from operating activities.

To summarize, we record our derivatives at fair value in our consolidated balance sheets. Gains and losses resulting from changes in fair value and upon settlement are reported as follows:

Derivative Type	Fair Value Gains / Losses	Financial Statement Reporting
Non-hedge derivatives and Hedge derivatives – ineffective portion	Unrealized and Realized	Reported in the Consolidated Income Statements as derivative fair value (gain) loss
Hedge derivatives – effective portion	Unrealized	Reported in Stockholders' Equity in the Consolidated Balance Sheets as accumulated other comprehensive income
	Realized	Reported in the Consolidated Income Statements and classified based on the hedged item (e.g., gas revenue, oil revenue or interest expense)

To designate a derivative as a cash flow hedge, we document at the hedge's inception our assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. The ineffective portion of the hedge is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. If, during the derivative's term, we determine the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses, based on the effective portion of the derivative at that date, are reclassified to earnings as oil or gas revenue or interest expense when the underlying transaction occurs. If it is determined that the designated hedge transaction is not probable to occur, any unrealized gains or losses are recognized immediately in the income statement as a derivative fair value gain or loss. During 2006, 2005 and 2004, there were no gains or losses reclassified into earnings as a result of the discontinuance of hedge accounting treatment for any of our derivatives.

Physical delivery contracts that are not expected to be net cash settled are deemed to be normal sales. However, physical delivery contracts that have a price not clearly and closely associated with the asset sold are not a normal sale and must be accounted for as a non-hedge derivative.

Revenue Recognition and Gas Balancing

Oil, gas and natural gas liquids revenues are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectibility of the revenue is reasonably assured. At times we may sell more or less than our entitled share of gas production. When this happens, we use the entitlement method of accounting for gas sales, based on our net revenue interest in production. Accordingly, revenue is deferred for gas deliveries in excess of our net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production. Our net gas imbalance payable of $2 million at December 31, 2006 was reported in the balance sheet as a $3 million net current receivable and a $5 million net long-term payable. At December 31, 2005, our net gas imbalance payable of $7 million was reported in the balance sheet as a $6 million net current receivable and a $13 million net long-term payable.

Gas Gathering, Processing and Marketing Revenues

We market our gas, as well as some gas produced by third parties, to brokers, local distribution companies and end-users. Gas gathering and marketing revenues are recognized in the month of delivery based on customer nominations. Gas processing and marketing revenues are recorded net of cost of gas sold of $287 million for 2006, $185 million for 2005 and $99 million for 2004. These amounts are net of intercompany eliminations.

Other Revenues

Other revenues result from and are related to our ongoing major operations. These revenues include various gains and losses, including from lawsuits and other disputes, as well as from non-significant sales of property and equipment.

Loss Contingencies

We account for loss contingencies in accordance with SFAS No. 5, *Accounting for Contingencies*. Accordingly, when management determines that it is probable that an asset has been impaired or a liability has been incurred, we accrue our best estimate of the loss if it can be reasonably estimated. Our legal costs related to litigation are expensed as incurred. See Note 6.

Interest

Interest expense includes amortization of deferred debt costs and is presented net of interest income of $3 million in 2006, $1 million in 2005 and less than $1 million in 2004, and net of capitalized interest of $18 million in 2006, $6 million in 2005 and $3 million in 2004. Interest is capitalized as producing property cost based on the weighted average interest rate and the cost of wells in process of drilling. Included in accounts payable and accrued liabilities is accrued interest of $54 million at December 31, 2006 and $32 million at December 31, 2005.

Stock-Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123 (Revised 2004), *Share-Based Payment,* which requires that compensation related to all stock-based awards, including stock options, be recognized in the financial statements based on their estimated grant-date fair value. We have previously recorded stock compensation pursuant to the intrinsic value method under APB Opinion No. 25, whereby compensation was recorded related to performance share and unrestricted share awards and no compensation was recognized for most stock option awards. We are using the modified prospective application method of adopting SFAS No. 123R, whereby the estimated fair value of unvested stock awards granted prior to January 1, 2006 will be recognized as compensation expense in periods subsequent to December 31, 2005, based on the same valuation method used in our prior pro forma disclosures. We have estimated expected forfeitures, as required by SFAS No. 123R, and we are recognizing compensation expense only for those awards expected to vest. Compensation expense is amortized over the estimated service period, which is the shorter of the award's time vesting period or the derived service period as implied by any accelerated vesting provisions when the common stock price reaches specified levels. All compensation must be recognized by the time the award vests. The cumulative effect of initially adopting SFAS No. 123R was immaterial. See Note 12.

The following are pro forma net income and earnings per share for the years ended December 31, 2005 and 2004, as if stock-based compensation had been recorded at the estimated fair value of stock awards at the grant date, as prescribed by SFAS No. 123, *Accounting for Stock-Based Compensation:*

	Year Ended December 31	
(in millions, except per share data)	2005	2004
Net income as reported	$ 1,152	$ 508
Add stock-based compensation expense included in the income statement, net of related tax effects	22	56
Deduct stock-based employee compensation expense determined under fair value method for all awards, net of related tax effects	(73)	(77)
Pro forma net income	$ 1,101	$ 487
Earnings per common share:		
Basic – as reported	$ 3.21	$ 1.53
Basic – pro forma	$ 3.07	$ 1.46
Diluted – as reported	$ 3.15	$ 1.51
Diluted – pro forma	$ 3.01	$ 1.45

Earnings per Common Share

In accordance with SFAS No. 128, *Earnings Per Share,* we report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities unless their impact is antidilutive. See Note 10.

Segment Reporting

In accordance with SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information,* we evaluated how the Company is organized and managed and have identified only one operating segment, which is the exploration and production of oil, natural gas and natural gas liquids. We consider our gathering, processing and marketing functions as ancillary to our oil and gas producing activities. All of our assets are located in the United States, and all revenues are attributable to United States customers.

Our production is sold to various purchasers, based on their credit rating and location of our production. For the year ended December 31, 2006, sales to each of two purchasers were approximately 22% and 15% total revenues. For the year ended December 31, 2005, sales to each of three purchasers were approximately 23%, 14% and 14% of total revenues. For the year ended December 31, 2004, sales to each of two purchasers were approximately 20% and 13% of total revenues. We believe that alternative purchasers are available, if necessary, to purchase production at prices substantially similar to those received from these significant purchasers. We currently have greater concentrations of credit with several A- or better rated integrated energy companies.

New Accounting Pronouncements

In September 2006, Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements*, was issued. SFAS No. 157 provides guidance for using fair value to measure assets and liabilities. It applies whenever other standards require or permit assets or liabilities to be measured at fair value, but it does not expand the use of fair value in any new circumstances. The provisions of SFAS No. 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007. The effect of adopting SFAS No. 157 has not been determined, but it is not expected to have a significant effect on our reported financial position or earnings.

Also in September 2006, SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – An Amendment of FASB Statements No. 87, 88, 106, and 132R*, was issued. SFAS No. 158 requires an employer to: (a) recognize in its statement of financial position an asset for a plan's overfunded status or a liability for a plan's underfunded status; (b) measure a plan's assets and its obligations that determine its funded status as of the end of the employer's fiscal year (with limited exceptions); and (c) recognize changes in the funded status of a defined benefit postretirement plan in comprehensive income in the year in which the changes occur. The requirement to recognize the funded status of a benefit plan and the disclosure requirements were adopted during fourth quarter 2006 (Note 12). The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. Since we do not have a defined benefit pension plan, this pronouncement relates only to our post-retirement health plan. The effect of adopting SFAS No. 158 was to increase other long-term liabilities by $2 million and to decrease accumulated other comprehensive income by the same amount.

In February 2007. SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities -Including an Amendment of FASB Statement No. 115*, was issued. SFAS No. 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The effect of adopting SFAS No. 159 has not been determined, but it is not expected to have a significant effect on reported financial position or earnings.

In July 2006, FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes – An Interpretation of FASB Statement No. 109*, was issued. FIN No. 48 clarifies financial statement recognition and disclosure requirements for uncertain tax positions taken or expected to be taken in a tax return. Financial statement recognition of the tax position is dependent on an assessment of a 50% or greater likelihood that the tax position will be sustained upon examination, based on the technical merits of the position. The provisions of FIN No. 48 must be adopted as of the beginning of fiscal years beginning after December 15, 2006, with the cumulative effect reported as an adjustment to retained earnings at the adoption date. The effect of adoption of FIN No. 48 has not been determined, but is not expected to have a significant effect on our reported financial position or earnings.

In September 2006, the SEC staff issued Staff Accounting Bulletin Topic 1N, *Financial Statements – Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* (SAB 108). SAB 108 provides guidance on how prior year misstatements should be evaluated when determining the materiality of misstatements in the current year financial statements. SAB 108 requires materiality to be determined by considering the effect of prior year misstatements on both the current year balance sheet and income statement, with consideration of their carryover and reversing effects. SAB 108 also addresses how to correct material misstatements. The provisions of SAB 108 are effective for financial statements issued for fiscal years ending after November 15, 2006. The effect of adopting SAB 108 did not have any effect on our reported financial position or earnings.

2. Related Party Transactions

A firm, affiliated with one of our nonemployee directors, has performed property acquisition advisory services for the Company. In February 2005, this firm was acquired by another company which continues to perform property acquisition advisory services for us, and a division of the company also performed co-manager services on our March 2006 and April 2005 senior note offerings (see Note 3). We paid this firm total fees of $78,500 in 2006, $5 million in 2005 and $9 million in 2004, and there were no amounts payable at December 31, 2006 or 2005.

A portion of the producing properties obtained in the ChevronTexaco acquisition (Note 13) were considered nonstrategic and marked for disposition at the time of purchase. In August 2004, we exchanged $38 million of these properties for 19,000 net contiguous acres in our new core operating area, the Barnett Shale of North Texas, and $25 million in other consideration. This exchange was with companies either wholly or majority owned by the adult children and a brother of Bob R. Simpson, Chairman and Chief Executive Officer of the Company. In connection with this exchange, we granted these companies an option to purchase other properties included in the ChevronTexaco acquisition. In March 2005, these companies purchased the properties for an adjusted purchase price of $11 million. Lehman Brothers Inc. provided a fairness opinion to the Board of Directors on the value of properties exchanged and sold.

In February 2007, in recognition of the Chairman and Chief Executive Officer of the Company and as part of a charitable giving program to support higher education, the Board of Directors approved a conditional contribution of $6.8 million to assist in building an athletics and academic center at Baylor University. This contribution is to be paid in two equal installments of $3.4 million. The first payment is expected to be paid in the first half of 2007 and the second is expected to be paid in the first half of 2008. Since this is a conditional contribution, the expense will not be included as general and administrative expense until such time as the condition is satisfied which is also the time of the expected payments. Concurrently, our Chairman and Chief Executive Officer, made a $3.2 million pledge for the same project. In return for these contributions, the Company and Mr. Simpson obtained naming rights for the building and certain facilities within the building.

3. Debt

Our long-term debt consists of the following:

(in millions)	December 31 2006	December 31 2005
Bank debt:		
Commercial paper, 5.5% at December 31, 2006	$ 159	$ –
Revolving credit agreement due April 2011	–	813
Term loan due April 2010, 6.1% at December 31, 2006	300	300
Senior notes:		
7 1/2%, due April 15, 2012	350	350
6 1/4%, due April 15, 2013	400	400
4.9%, due February 1, 2014, net of discount	497	497
5%, due January 31, 2015, net of discount	350	350
5.3% due June 30, 2015, net of discount	399	399
5.65%, due April 1, 2016, net of discount	400	–
6.1%, due April 1, 2036, net of discount	596	–
Total long-term debt	$ 3,451	$ 3,109

Other than borrowings under our commercial paper program, revolving credit agreement and term loan, no debt matures within five years. Because we had both the intent and ability to refinance the commercial paper balance outstanding with borrowings under our revolving credit facility due in April 2011, we have classified these borrowings as long-term debt in our consolidated balance sheets. Before the stated maturities of April 2010 or April 2011, we may renegotiate the commercial paper program, revolving credit agreement and term loan to increase the borrowing commitment and extend the maturity.

Commercial Paper

In November 2006, we initiated a commercial paper program. We may borrow up to $1.5 billion under this program. Borrowings under the commercial paper program reduce our available capacity under the revolving credit facility on a dollar-for-dollar basis. The commercial paper borrowings may have terms up to 397 days and bear interest at rates agreed to at the time of the borrowing. The interest rate is based on a standard index such as the Federal Funds Rate, LIBOR, or the money market rate as found on the commercial paper market. On December 31, 2006, borrowings were $159 million at an interest rate of 5.5%. The weighted average interest rate on commercial paper borrowings was 5.4% during 2006.

Bank Debt

On December 31, 2006, we had no borrowings under our revolving credit agreement with commercial banks, and we had available borrowing capacity of $1.34 billion net of our commercial paper borrowings. In March 2006, we amended this agreement to, among other things, reduce the commitment fees and spread on our Eurodollar loans, eliminate the covenant restricting our ability to make investments, expand our ability to incur liens and extend the maturity date one year. The facility matures April 1, 2011, with annual options to request successive one-year extensions.

The interest rate on any borrowings is generally based on the one-month LIBOR plus 0.40%. Interest is paid at maturity, or quarterly if the term is for a period of 90 days or more. We also incur a commitment fee on unused borrowing commitments, which is 0.09%. The agreement requires us to maintain a ratio of debt-to-total capitalization of not more than 60%. We use the facility for general corporate purposes and as a backup facility for our new commercial paper program (see above). The weighted average interest rate on bank debt was 5.4% during 2006, 4.3% during 2005 and 2.6% during 2004.

In October 2006, we amended our revolving credit agreement to remove borrowing restrictions under any "material adverse effect" clauses. Credit agreements commonly include such clauses which can remove the bank's obligation to fund their commitment if any condition or event would reasonably be expected to have a material and adverse effect on the borrower's financial condition, operations, properties or business considered as a whole, the borrower's ability to make timely debt payments, or the enforceability of material terms of the credit agreement. While our revolving credit agreement includes covenants that require us to report a condition or event having a material adverse effect on the Company, the obligation of the banks to fund the revolving credit agreement is not conditioned on the absence of a material adverse effect.

In March 2006, we amended our $300 million term loan credit agreement to conform its covenants to our bank revolving credit agreement. However, we did not amend the pricing or extend the maturity of the term loan.

In July 2006, our credit rating was upgraded by Standard & Poor's to BBB and by Moody's to Baa2. As a result of these upgrades, the interest rate on future borrowings was reduced by 0.15% under our revolving credit facility and by 0.125% under our term loan.

We entered into unsecured and uncommitted lines of credit with commercial banks in the amount of $200 million in October 2006, $100 million in January 2006 and $25 million in October 2006. As of December 31, 2006, there were no borrowings under these lines.

Senior Notes

In January 2004, we sold $500 million of 4.9% senior notes that were issued at 99.34% of par to yield 4.98% to maturity. The notes mature in February 2014 and interest is payable each February 1 and August 1. Net proceeds of $490 million were used to fund our January 2004 property acquisitions of $243 million (Note 13) and to reduce bank debt.

In September 2004, we sold $350 million of 5% senior notes that were issued at 99.918% of par to yield 5.011% to maturity. The notes are due in January 2015 and interest is payable each January 31 and July 31. Net proceeds of $347 million were used to reduce bank debt associated with our 2004 acquisitions.

In April 2005, we sold $400 million of 5.3% senior notes at 99.683% of par to yield 5.338% to maturity. The notes mature in June 2015 and interest is payable each June 30 and December 30. Net proceeds of approximately $395 million were used to reduce borrowings under our bank revolving credit facility.

In March 2006, we sold $400 million of 5.65% senior notes due April 1, 2016 and $600 million of 6.1% senior notes due April 1, 2036. The 5.65% senior notes were issued at 99.917% of par to yield 5.661% to maturity. The 6.1% senior notes were issued at 99.346% of par to yield 6.148% to maturity. Interest is payable on both series of notes each April 1 and October 1, beginning October 1, 2006. Net proceeds of approximately $987 million were used to reduce borrowings outstanding under our bank revolving credit facility and for other general corporate purposes.

The senior notes require no sinking fund. We may redeem all or a part of the senior notes at any time at a price of 100% of their principal balance plus accrued interest and a make-whole premium payment. The make-whole premium is calculated as any excess over the principal balance of the present value of remaining principal and interest payments at the U.S. Treasury rate for a comparable maturity plus no more than 0.25%.

4. Income Tax

The following reconciles our income tax expense to the amount calculated at the statutory federal income tax rate:

(in millions)	2006	2005	2004
Income tax expense at the federal statutory rate (35%)	$ 1,036	$ 634	$ 289
State and local income taxes and other (a)	65	24	29
Income tax expense	$ 1,101	$ 658	$ 318

(a) The 2006 provision includes $34 million related to enactment of a new State of Texas margin tax.

Components of income tax expense are as follows:

(in millions)	2006	2005	2004
Current income tax (a)	$ 572	$ 243	$ 63
Deferred income tax	505	398	167
Net operating loss carryforwards used	24	17	88
Income tax expense	$ 1,101	$ 658	$ 318

(a) The current income tax provision exceeds cash tax expense by the benefit realized upon exercise of stock options not expensed in the financial statements. This benefit, which is recorded in additional paid-in capital, was $50 million in 2006, $21 million in 2005 and $18 million in 2004.

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and tax bases of assets and liabilities. Our net deferred tax assets and liabilities are recorded as a current liability of $263 million and a long-term liability of $1.98 billion at December 31, 2006 and as a current liability of $38 million and a long-term liability of $1.39 billion at December 31, 2005. Significant components of net deferred tax assets and liabilities are:

	December 31	
(in millions)	2006	2005
Deferred tax assets:		
Net operating loss carryforwards	$ –	$ 24
Derivative fair value loss	22	35
Other	43	18
Total deferred tax assets	65	77
Deferred tax liabilities:		
Property and equipment	(1,971)	(1,426)
Derivative fair value gain	(319)	(70)
Other	(16)	(9)
Total deferred tax liabilities	(2,306)	(1,505)
Net deferred tax liabilities	$ (2,241)	$ (1,428)

As of December 31, 2006, all tax loss carryforwards and alternative minimum tax credit carryforwards have been fully utilized.

5. Asset Retirement Obligation

Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state laws. We determine our asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The following is a summary of asset retirement obligation activity for the years ended December 31, 2006 and 2005:

(in millions)	2006	2005
Asset retirement obligation, January 1	$ 223	$ 160
Revisions in the estimated cash flows	36	16
Liability incurred upon acquiring and drilling wells	35	37
Liability settled upon plugging and abandoning wells	(3)	(2)
Accretion of discount expense	16	12
Asset retirement obligation, December 31	307	223
Less current portion	(4)	(4)
Asset retirement obligation, long term	$ 303	$ 219

6. Commitments and Contingencies

Leases

We lease compressors, offices, vehicles, aircraft and certain other equipment in our primary locations under noncancelable operating leases. Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. As of December 31, 2006, minimum future lease payments for all noncancelable lease agreements (including the sale and operating leaseback agreements described below) were as follows:

(in millions)	
2007	$ 27
2008	23
2009	19
2010	16
2011	11
Remaining	16
Total	$ 112

Amounts incurred under operating leases (including renewable monthly leases) were $55 million in 2006, $41 million in 2005 and $35 million in 2004.

In March 1996, we sold our Tyrone gas processing plant and related gathering system and entered an agreement to lease the facility from the buyers for an initial term of eight years with fixed renewal options for an additional 13 years. This transaction was recorded as a sale and operating leaseback, with no gain or loss on the sale. In September 2006, we extended the lease until March 2008.

In November 1996, we sold a gathering system in Major County, Oklahoma and entered an agreement to lease the facility from the buyers for an initial term of eight years, with fixed renewal options for an additional ten years. This transaction was recorded as a sale and operating leaseback, with a deferred gain on the sale. The deferred gain was fully recognized at December 31, 2006. In May 2006, we extended the lease until November 2007.

Under each of the above sale and leaseback transactions, we do not have the right or option to purchase, nor does the lessor have the obligation to sell, the facility at any time. However, if the lessor decides to sell the facility at the end of the initial term or any renewal period, the lessor must first offer to sell it to us at its fair market value. Additionally, we have the right of first refusal of any third party offers to buy the facility after the initial term.

Purchase Commitments

As of December 31, 2006, we have entered into contracts with various providers to purchase certain other property and equipment. These future commitments will result in expected payments of $66 million in 2007 and $17 million in 2008.

Transportation Contracts

We have entered firm transportation contracts with various pipelines. Under these contracts we are obligated to transport minimum daily gas volumes, as calculated on a monthly basis, or pay for any deficiencies at a specified reservation fee rate. Our production committed to these pipelines is expected to exceed the minimum daily volumes provided in the contracts. We have generally delivered at least minimum volumes under our firm transportation contracts, therefore avoiding payment for deficiencies. As of December 31, 2006, maximum commitments under our transportation contracts were as follows:

(in millions)	
2007	$ 61
2008	69
2009	74
2010	73
2011	66
Remaining	295
Total	$ 638

In October 2005, we entered into a ten-year firm transportation agreement that commences upon completion of a new 168-mile pipeline spanning from East Texas to northeast Louisiana. Upon the pipeline's completion, currently expected in second quarter 2007, we will transport daily gas volumes for a minimum monthly transportation fee of $3 million plus fuel ranging from 0.8% to 1.6%, depending on receipt point and other conditions.

In December 2006, we entered into a ten-year firm transportation contract that commences upon completion of a new 502-mile pipeline spanning from southeast Oklahoma to east Alabama. Upon the pipeline's completion, currently expected in first quarter 2009, we will transport gas volumes for a minimum transportation fee of $2 million per month plus fuel not to exceed 1.2%, depending on receipt point and other conditions.

The potential effect of these agreements is not included in the above summary of our transportation contract commitments since our commitment is contingent upon completion of the pipelines.

Guarantees

Under the terms of some of our operating leases for compressors, airplanes and vehicles, we have various residual value guarantees and other payment provisions upon our election to return the equipment under certain specified conditions. As of December 31, 2006, we estimate the total contingent payable under these guarantees does not exceed $5 million.

Employment Agreements

Three executive officers entered into year-to-year employment agreements with us in May 2006. The agreements are automatically renewed each year-end unless terminated by either party upon thirty days notice prior to each November 30. Under these agreements, the officers receive a minimum annual salary of $1,200,000, $675,000 and $540,000, respectively, and are entitled to participate in any incentive compensation programs administered by the Board of Directors. The agreement also provides that, in the event (i) the officer terminates his employment for good reason, as defined in the agreement, (ii) we terminate the employee without cause, (iii) the officer dies or becomes disabled, or (iv) a change in control of the Company occurs, the officer is entitled to a lump-sum payment of three times the officer's most recent annual compensation, including any special bonuses or other compensation required to be designated as a bonus under the rules and regulations of the Securities and Exchange Commission. In addition, the officer is entitled to receive a payment sufficient to make the officer whole for any excise tax on excess parachute payments imposed by the Internal Revenue Code.

Upon retirement, each of these officers will enter into an eighteen-month consulting agreement under which the officer will receive a monthly payment based on his annual salary at the time of retirement, plus $10,000 a month for expenses. The officer will also become fully vested in any outstanding share-based awards unless otherwise provided in the award agreement (Note 12).

Commodity Commitments

We have entered into futures contracts, collars and swap agreements that effectively fix gas and oil prices. See Note 8.

Drilling Contracts

As of December 31, 2006, we have contracts with various drilling contractors to use 63 drilling rigs in 2007 with terms of up to three years and minimum future commitments of $171 million in 2007, $49 million in 2008 and $17 million in 2009. Early termination of these contracts at December 31, 2006 would have required us to pay maximum penalties of $119 million. We do not expect to pay any early termination penalties related to these contracts.

Litigation

On October 17, 1997, an action, styled *United States of America ex rel. Grynberg v. Cross Timbers Oil Company, et al.*, was filed in the U.S. District Court for the Western District of Oklahoma by Jack J. Grynberg on behalf of the United States under the *qui tam* provisions of the U.S. False Claims Act against the Company and certain of our subsidiaries. The plaintiff alleges that we underpaid royalties on natural gas produced from federal leases and lands owned by Native Americans in amounts in excess of 20% as a result of mismeasuring the volume of natural gas, incorrectly analyzing its heating content and improperly valuing the natural gas during at least the past ten years. The plaintiff seeks treble damages for the unpaid royalties (with interest, attorney fees and expenses), civil penalties between $5,000 and $10,000 for each violation of the U.S. False Claims Act, and an order for us to cease the allegedly improper measuring practices. This lawsuit against us and similar lawsuits filed by Grynberg against more than 300 other companies were consolidated in the United States District Court for Wyoming. In October 2002, the court granted a motion to dismiss Grynberg's royalty valuation claims, and Grynberg's appeal of this decision was dismissed for lack of appellate jurisdiction in May 2003. In response to a motion to dismiss filed by us and other defendants, in October 2006 the district judge held that Grynberg failed to establish jurisdictional requirements to maintain the action against us and other defendants and dismissed the action for lack of subject matter jurisdiction. Grynberg has filed an appeal of this decision. The district judge did not dismiss those claims against us pertaining to the royalty value of carbon dioxide. While we are unable to predict the final outcome of this case, we believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

In June 2001, we were served with a lawsuit styled *Price, et al. v. Gas Pipelines, et al.* The action was filed in the District Court of Stevens County, Kansas, against us and one of our subsidiaries, along with over 200 natural gas transmission companies, producers, gatherers and processors of natural gas. The plaintiffs seek to represent a class of plaintiffs consisting of all similarly situated gas working interest owners, overriding royalty owners and royalty owners either from whom the defendants had purchased natural gas or who received economic benefit from the sale of such gas since January 1, 1974. The allegations in the case are similar to those in the *Grynberg* case; however, the *Price* case broadens the claims to cover all oil and gas leases (other than the federal and Native American leases that are the subject of the *Grynberg* case). The complaint alleges that the defendants have mismeasured both the volume and heating content of natural gas delivered into their pipelines, resulting in underpayments to the plaintiffs. The plaintiffs assert a breach of contract claim, negligent or intentional misrepresentation, civil conspiracy, common carrier liability, conversion, violation of a variety of Kansas statutes and other common law causes of action. The amount of damages was not specified in the complaint. In February 2002, we, along with one of our subsidiaries, were dismissed from the suit and another subsidiary of the Company was added. A hearing was held in January 2003, and the court held that a class should not be certified. The plaintiffs' counsel has filed an amended class action petition, which reduces the proposed class to only royalty owners, reduces the claims to mismeasurement of volume only, conspiracy, unjust enrichment and accounting, and only applies to gas measured in Kansas, Colorado and Wyoming. The court held an evidentiary hearing in April 2005 to determine whether the amended class should be certified, and we are awaiting the decision of the court. While we are unable to predict the outcome of this case, we believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

On August 5, 2003, the Price plaintiffs served one of our subsidiaries with a new original class action petition styled *Price, et al. v. Gas Pipelines, et al.* The action was filed in the District Court of Stevens County, Kansas, against natural gas pipeline owners and operators. The plaintiffs seek to represent a class of plaintiffs consisting of all similarly situated gas royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The new petition alleges the same improper analysis of gas heating content that had previously been alleged in the *Price* case discussed above until it was removed from the case by the filing of the amended class action petition. In all other respects, the new petition appears to be identical to the amended class action petition in that it has a proposed class of only royalty owners, alleges conspiracy, unjust enrichment and accounting, and only applies to gas measured in Kansas, Colorado and Wyoming. The court held an evidentiary hearing in April 2005 to determine whether the amended class should be certified, and we are awaiting the decision of the court. The amount of damages was not specified in the complaint. While we are unable to predict the outcome of this case, we believe that the allegations of this lawsuit are without merit and intend to vigorously defend the action. Any potential liability from this claim cannot currently be reasonably estimated, and no provision has been accrued in our financial statements.

We are involved in various other lawsuits and certain governmental proceedings arising in the ordinary course of business. Our management and legal counsel do not believe that the ultimate resolution of these claims, including the lawsuits described above, will have a material effect on our financial position or liquidity, although an unfavorable outcome could have a material adverse effect on the operations of a given interim period or year.

Other

In May 2005, in recognition of the Chairman and Chief Executive Officer of the Company, in support of local education and to benefit our ongoing oil and gas business endeavors in this area, the Board of Directors approved a pledge to contribute $3.1 million to a school in Fort Worth. Of this amount, $3 million is to be used for capital improvements. The remaining $100,000 is to be used for a scholarship fund for economically disadvantaged students. This pledge is to be paid annually in four equal installments of $775,000, the first of which was paid in June 2005 with the remaining payments due in June of each subsequent year. The total contribution was expensed as general and administrative expense in 2005. As of December 31, 2006, the remaining $1.6 million pledge payable is included in accounts payable and accrued liabilities.

To date, our expenditures to comply with environmental or safety regulations have not been significant and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

To secure tubular goods required to support our drilling program, we provide a forecast to a tubular goods supplier who commits to deliver, at market prices, our next quarter's tubular products. There is no minimum order requirement, and the forecast can be adjusted 60 to 90 days prior to shipment.

Through December 2006, we have acquired approximately 214,000 net acres in the Barnett Shale of North Texas. Many of these net acres are generally subject to lease expiration if initial wells are not drilled within a specified period, generally not exceeding two years. We do not expect to lose significant lease acreage because of failure to drill due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, we have allowed certain lease acreage to expire and may allow additional acreage to expire in the future.

In addition to drilling four wells to earn our 50% working interest in the 69,500 acres granted under our Piceance Basin farm-in agreement with ExxonMobil Corporation (Note 13), we are required to continue to drill wells periodically to retain the undeveloped leasehold until the entire acreage position has been drilled.

See Note 2.

7. Financial Instruments

We use commodity-based and financial derivative contracts to manage exposures to commodity price and interest rate fluctuations. We do not hold or issue derivative financial instruments for speculative or trading purposes. We also may enter gas physical delivery contracts to effectively provide gas price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts. Therefore, these contracts are not recorded in the financial statements.

All derivatives are recorded on the balance sheet at estimated fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date, and/or the value confirmed by the counterparty. Changes in the fair value of effective cash flow hedges are recorded as a component of accumulated other comprehensive income, which is later transferred to earnings when the hedged transaction occurs. Changes in the fair value of derivatives that are not designated as hedges, as well as the ineffective portion of the hedge derivatives, are recorded in derivative fair value (gain) loss in the income statement. This ineffective portion is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. Btu swap contracts do not qualify for hedge accounting.

Btu Swap Contracts

In 1995, we entered a contract to sell gas based on crude oil pricing, also referred to as the Enron Btu swap contract. This contract was terminated as a result of the Enron bankruptcy in December 2001. Because the contract pricing was not clearly and closely associated with natural gas prices, it was considered a non-hedge derivative financial instrument, with changes in fair value recorded as a derivative (gain) loss in the income statement.

Prior to termination of the Enron Btu swap contract, we entered Btu swap contracts with another counterparty to effectively defer until August 2005 through July 2006 any cash flow impact related to 25,000 Mcf of daily gas deliveries in 2002 that were to be made under the Enron Btu swap contract. Changes in fair value of these contracts were recorded as a derivative (gain) loss in the income statement. In March 2002, we terminated some of these contracts with maturities of May through December 2002 and received $7 million from the counterparty.

Btu swap contracts outstanding at December 31, 2005 had a net fair value loss of $23 million. As of February 28, 2006, we terminated the remaining portion of these contracts, resulting in total payments to the counterparty of $7 million in first quarter 2006.

Commodity Price Hedging Instruments

We periodically enter into futures contracts, energy swaps, collars and basis swaps to hedge our exposure to price fluctuations on crude oil and natural gas sales. When actual commodity prices exceed the fixed price provided by these contracts, we pay this excess to the counterparty, and when actual commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. See Note 8.

Derivative Fair Value (Gain) Loss

The components of derivative fair value (gain) loss, as reflected in the consolidated income statements are:

(in millions)	2006	2005	2004
Change in fair value of Btu swap contracts	$ (16)	$ 23	$ 1
Change in fair value of other derivatives that do not qualify for hedge accounting	(19)	(37)	(1)
Ineffective portion of derivatives qualifying for hedge accounting	(67)	1	12
Derivative fair value (gain) loss	$ (102)	$ (13)	$ 12

The gains in 2006 and 2005 related to derivatives that do not qualify for hedge accounting are primarily related to natural gas basis swap agreements. Except to the extent basis swap agreements are utilized in conjunction with NYMEX future contracts, they cannot qualify for hedge accounting.

Fair Value of Financial Instruments

Because of their short-term maturity, the fair value of cash and cash equivalents, accounts receivable and accounts payable approximates their carrying values at December 31, 2006 and 2005. The following are estimated fair values and carrying values of our other financial instruments at each of these dates:

	Asset (Liability)			
	December 31, 2006		December 31, 2005	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivative Assets:				
Fixed-price natural gas futures and swaps	$ 669	$ 669	$ 194	$ 194
Fixed-price crude oil futures and differential swaps	191	191	–	–
Derivative Liabilities:				
Fixed-price natural gas futures and swaps	(37)	(37)	(50)	(50)
Fixed-price crude oil futures and differential swaps	(1)	(1)	(17)	(17)
Btu swap contracts	–	–	(23)	(23)
Net derivative asset	$ 822	$ 822	$ 104	$ 104
Long-term debt	$ (3,451)	$ (3,427)	$ (3,109)	$ (3,154)

The fair value of futures, swap and differential agreements is estimated based on the exchange-trade value of NYMEX, basis and differential contracts and market commodity prices for the applicable future periods. The fair value of bank borrowings approximates their carrying value because of short-term interest rate maturities. The fair value of senior notes is based on current market quotes.

Changes in fair value of derivative assets and liabilities are the result of changes in oil and gas prices. Futures and swaps are generally designated as hedges of commodity price risks, and accordingly, changes in their values are predominantly recorded in accumulated other comprehensive income until the hedged transaction occurs.

Concentrations of Credit Risk

Although our cash equivalents, accounts receivable and derivative assets are exposed to the risk of credit loss, we do not believe such risk to be significant. Cash equivalents are high-grade, short-term securities, placed with highly rated financial institutions. Most of our receivables are from a diverse group of companies including major energy companies, pipeline companies, local distribution companies and end-users in various industries. We currently have greater concentrations of credit with several A- or better rated integrated energy companies. Financial and commodity-based swap contracts expose us to the credit risk of nonperformance by the counterparty to the contracts. This exposure is diversified among major investment grade financial institutions, and we have master netting agreements with counterparties that provide for offsetting payables against receivables from separate derivative contracts. Letters of credit or other appropriate security are obtained as considered necessary to limit risk of loss. Our allowance for collectibility of all accounts receivable was $5 million at December 31, 2006 and $4 million as of December 31, 2005.

8. Commodity Sales Commitments

Our policy is to consider hedging a portion of our production at commodity prices management deems attractive. While there is a risk we may not be able to realize the benefit of rising prices, management may enter into hedging agreements because of the benefits of predictable, stable cash flows.

In addition to selling gas under fixed price physical delivery contracts, we enter futures contracts, energy swaps, collars and basis swaps to hedge our exposure to price fluctuations on natural gas and crude oil sales. When actual commodity prices exceed the fixed price provided by these contracts we pay this excess to the counterparty, and when the commodity prices are below the contractually provided fixed price, we receive this difference from the counterparty. We have hedged a portion of our exposure to variability in future cash flows from natural gas sales through December 2007 and from crude oil sales through December 2008.

Natural Gas

We have entered into natural gas futures contracts and swap agreements that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. See Note 7 regarding accounting for commodity hedges.

Production Period		Futures Contracts and Swap Agreements: Mcf per Day	Futures Contracts and Swap Agreements: Average NYMEX Price per Mcf
2007	January	700,000	$ 9.55
	February	800,000	$ 9.33
	March to December	900,000	$ 9.19

The price we receive for our gas production is generally less than the NYMEX price because of adjustments for delivery location ("basis"), relative quality and other factors. We have entered sell basis swap agreements that effectively fix the basis adjustment as shown below. Not all of our sell basis swap agreements are designated as hedges for hedge accounting purposes.

Production Period		Mcf per Day	Weighted Average Sell Basis per Mcf(a)
2007	January to March	460,000	$ 0.66
	April	410,000	$ 0.35
	May to October	210,000	$ 0.47
	November to December	90,000	$ 0.39
2008	January to December	30,000	$ 0.39

(a) Reductions to NYMEX gas prices for delivery location.

Net settlements on futures and sell basis swap hedge contracts increased gas revenues by $618 million in 2006 and decreased gas revenue by $127 million in 2005 and $156 million in 2004. As of December 31, 2006, an unrealized pre-tax derivative fair value gain of $599 million, related to cash flow hedges of gas price risk, was recorded in accumulated other comprehensive income. This gain is expected to be reclassified into earnings in 2007. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date. The settlement of futures contracts and sell basis swap agreements related to January 2007 gas production increased gas revenue by approximately $55 million, or $1.45 per Mcf.

Crude Oil

We have entered into crude oil futures contracts and swap agreements that effectively fix prices for the production and periods shown below. Prices to be realized for hedged production may be less than these fixed prices because of location, quality and other adjustments. See Note 7 regarding accounting for commodity hedges.

Production Period		Futures Contracts and Swap Agreements: Bbls per Day	Futures Contracts and Swap Agreements: Average NYMEX Price per Bbl
2007	January to December	37,500	$ 74.40
2008	January to December	22,500	$ 74.26

We have entered crude sweet and sour differential swaps of $5.27 per Bbl for 15,000 Bbls per day of sour crude oil production for January 2007, and $5.14 per Bbl for 20,000 Bbls per day for February to December 2007.

Net gains on futures and differential swap hedge contracts increased oil revenue by $3 million in 2006, and net losses reduced oil revenue by $75 million in 2005 and $15 million in 2004. As of December 31, 2006, an unrealized pre-tax derivative fair value gain of $176 million related to cash flow hedges of oil price risk was recorded in accumulated other comprehensive income. Based on December 31 mark-to-market prices, $123 million of this gain is expected to be reclassified into earnings in 2007. The actual reclassification to earnings will be based on mark-to-market prices at the contract settlement date. The settlement of futures contracts, swap agreements and differential swap contracts related to January 2007 production increased oil revenue by approximately $22 million, or $15.00 per Bbl.

Transportation Contracts

In connection with our commitments under our transportation contracts (Note 6), we have entered purchase basis swap agreements related to potential purchase of gas volumes to be transported. Purchase basis swap agreements are not designated as hedges for hedge accounting purposes.

Period		Mcf per Day	Weighted Average Purchase Basis per Mcf(a)
2007	January	125,000	$ 1.01
	February to March	120,000	$ 1.01
	April to October	30,000	$ 0.79
	November to December	10,000	$ 0.62
2008	January to March	10,000	$ 0.62

(a) Reductions to NYMEX gas prices for purchase location.

Physical Delivery Contracts

In 1998, we sold a production payment, payable from future production from certain properties acquired in an acquisition, to EEX Corporation for $30 million. The acquisition was recorded net of the sale of the production payment. Under the terms of the production payment conveyance and related delivery agreement, we committed to deliver to EEX a total of approximately 34.3 Bcf of gas during the 10-year period beginning January 1, 2002, with scheduled deliveries by year, subject to certain variables. EEX will reimburse us for all royalty and production and property tax payments related to such deliveries. EEX will also pay us an operating fee of $0.257 per Mcf for deliveries, which fee will be escalated annually at a rate of 5.5%. In 2001 and 2002, we repurchased 18.3 Bcf (14.8 Bcf net) of gas under the production payment for $21 million. We began delivery of the remaining 16.0 Bcf of gas in September 2006. As of December 31, 2006, remaining volumes to be delivered under this commitment are 15.0 Bcf.

9. Equity

Stock Splits

We effected a five-for-four stock split on March 17, 2004 and a four-for-three stock split on March 15, 2005. All common stock shares, treasury stock shares and per share amounts have been retroactively restated to reflect these stock splits.

Common Stock

The following reflects our common stock activity:

	Shares Issued			Shares in Treasury		
(in thousands)	2006	2005	2004	2006	2005	2004
Balance, January 1	365,221	348,428	312,335	1,655	1,250	–
Issuance/vesting and forfeiture of performance, restricted and unrestricted shares	1,217	433	2,448	65	405	1,216
Stock option and warrant exercises	2,481	3,027	1,937	–	–	–
Treasury stock purchases	–	–	–	2,200	–	34
Common stock offering	–	–	31,708	–	–	–
Issuance for acquisition of corporation	2,555	13,333	–	–	–	–
Balance, December 31	371,474	365,221	348,428	3,920	1,655	1,250

Our acquisition of Peak Energy Resources, Inc. in June 2006 was partially funded through issuance to the seller of 2.555 million shares of common stock (Note 13). We registered these shares under our shelf registration statement (see below) in June 2006.

Our acquisition of Antero Resources Corporation in April 2005 was partially funded through issuance to the seller of 13.3 million shares of common stock (Note 13). We filed a shelf registration with the Securities and Exchange Commission for the resale of the common stock including shares to be issued upon exercise of warrants. See Common Stock Warrants below.

In May 2004, we completed a public offering of 31.7 million shares of common stock at $18.92 per share. After underwriting discount and other offering costs of $20 million, net proceeds of $580 million were used to reduce bank borrowings that funded our producing property acquisitions from ExxonMobil Corporation and our deposit on the ChevronTexaco acquisition (Note 13).

Treasury Stock

In August 2004, our Board of Directors authorized the repurchase of up to 20 million shares of our common stock which may be purchased from time to time in open market or negotiated transactions. This authorization effectively replaced the share repurchase authorization remaining from May 2000. In June 2006, we repurchased 2.2 million shares of our common stock on the open market at $37.80 per share, or a total of $83 million. As of December 31, 2006, we have repurchased 2,233,600 shares.

Stockholder Rights Plan

In August 1998, the Board of Directors adopted a stockholder rights plan that is designed to assure that all stockholders receive fair and equal treatment in the event of any proposed takeover of the Company. Under this plan, one preferred share purchase right is attached to each outstanding share of common stock. Each right entitles stockholders to buy one one-thousandth of a share of newly created Series A Junior Participating Preferred Stock at an exercise price of $80, subject to adjustment in the event a person acquires or makes a tender or exchange offer for 15% or more of the outstanding common stock. In such event, each right entitles the holder (other than the person acquiring 15% or more of the outstanding common stock) to purchase shares of common stock with a market value of twice the right's exercise price. At any time prior to such event, the Board of Directors may redeem the rights at one cent per right. The rights can be transferred only with common stock and expire in August 2008.

Shelf Registration Statement

In June 2006, we filed a shelf registration statement with the Securities and Exchange Commission to potentially offer securities which could include debt securities or common stock. The securities will be offered at prices and on terms to be determined at the time of sale. Net proceeds from the sale of such securities will be used for general corporate purposes, including reduction of bank debt.

Common Stock Warrants

Our purchase of Antero Resources Corporation was partially funded by issuance of warrants to purchase 2.1 million shares of common stock at $25.97 per share (Note 13). The warrants expire in March 2010.

Common Stock Dividends

The Board of Directors declared quarterly dividends of $0.0075 per common share for first and second quarter 2004, $0.0375 per common share for third and fourth quarter 2004, $0.05 per common share for the first three quarters of 2005, $0.075 per common share for fourth quarter 2005 and first three quarters 2006 and $0.09 per common share for fourth quarter 2006. On February 20, 2007, the Board of Directors declared a $0.12 per common share dividend for first quarter 2007.

In January 2006, the Board of Directors declared a dividend to common stockholders, consisting of all 21.7 million Hugoton Royalty Trust units owned by us. The dividend ratio of 0.059609 trust units for each common share outstanding was set on the record date of April 26, 2006. The units were distributed on May 12, 2006, when this dividend was recorded. We recorded this dividend at $614 million, or approximately $1.687 per common share, the fair market value of the units based on the May 12, 2006 average high and low New York Stock Exchange trade price of $28.31.

The determination of the amount of future dividends, if any, to be declared and paid is at the sole discretion of the Board of Directors and will depend on our financial condition, earnings and cash flow from operations, the level of our capital expenditures, our future business prospects and other matters the Board of Directors deems relevant.

See Note 12.

10. Earnings Per Share

The following reconciles earnings (numerator) and shares (denominator) used in the computation of basic and diluted earnings per share:

(in millions, except per share data)	Earnings	Shares	Earnings per Share
2006			
Basic	$ 1,860	364.8	$ 5.10
Effect of dilutive securities:			
Stock options	–	4.1	
Warrants	–	0.9	
Diluted	$ 1,860	369.8	$ 5.03
2005			
Basic	$ 1,152	358.4	$ 3.21
Effect of dilutive securities:			
Stock options	–	6.8	
Warrants	–	0.4	
Diluted	$ 1,152	365.6	$ 3.15
2004			
Basic	$ 508	332.9	$ 1.53
Effect of dilutive securities:			
Stock options	–	2.8	
Diluted	$ 508	335.7	$ 1.51

11. Supplemental Cash Flow Information

The consolidated statements of cash flows exclude the following non-cash transactions:

- Distribution of 21.7 million Hugoton Royalty Trust units as a dividend to common stockholders in May 2006 (Note 9)
- Non-cash components of the June 2006 Peak Energy Resources acquisition purchase price, including issuance of 2.555 million shares of common stock and assumption of other liabilities (Note 13)
- Exchange of producing properties with ConocoPhillips in March 2005 and Occidental Petroleum in September 2005 (Note 13)
- Non-cash components of the April 2005 Antero Resources acquisition purchase price, including issuance of 13.3 million shares of common stock and warrants to purchase 2.1 million shares of common stock, and assumption of debt and other liabilities (Note 13)
- Exchange of nonstrategic working and royalty interests for nonproducing acres in August 2004 (Note 2)
- Grants of 1.0 million restricted shares in 2006
- Grants and immediate vesting of unrestricted common shares to nonemployee directors totaling 20,000 shares in 2006 and 18,000 shares in each of 2005 and 2004
- The following performance share activity (Note 12):
  - Grants of 150,000 shares in 2006, 414,000 shares in 2005 and 2.6 million shares in 2004
  - Vesting of 161,000 shares in 2006, 1.1 million in 2005 and 3.2 million shares in 2004

Interest payments in 2006 totaled $172 million (including $18 million of capitalized interest), $150 million in 2005 (including $6 million of capitalized interest) and $77 million in 2004 (including $3 million of capitalized interest). Net income tax payments were $556 million during 2006, $248 million during 2005 and $50 million during 2004.

Prior to January 1, 2006, we did not recognize compensation expense related to stock options granted. Because of this, the tax benefit realized upon exercise of stock options has been recorded as an increase in additional paid-in capital. This tax benefit has decreased our current income tax payable and, as reflected in our consolidated statements of cash flows, has increased our cash provided by operating activities by $21 million in 2005 and $18 million in 2004. Upon adoption of SFAS 123R (Note 12), this tax benefit for 2006 of $50 million has been classified as cash provided by financing activities.

12. Employee Benefit Plans

401(k) Plan

We sponsor a 401(k) benefit plan that allows employees to contribute and defer a portion of their wages. We match employee contributions of up to 10% of wages, subject to annual dollar maximums established by the federal government. Employee contributions vest immediately while our matching contributions vest 100% upon completion of three years of service. All employees over 21 years of age may participate. Company contributions under the plan were $11 million in 2006, $9 million in 2005 and $7 million in 2004.

Post-Retirement Health Plan

Effective January 1, 2001, we adopted a medical plan for employees who retire at age 55 or over, as well as directors age 55 or over, with a minimum of five years service. During 2003, our retiree medical plan was amended to provide benefits to employees and directors when their combined age and qualified years of service total 60, with a minimum age of 45 and a minimum of five years of service. Benefits under the plan are the same as for active employees, and continue until the retired employee or director or dependents are eligible for Medicare or another similar state health insurance program. Post-retirement medical benefits are not prefunded but are paid when incurred. The plan's benefit obligation, funded status and net periodic benefit cost for 2006, 2005 and 2004 are as follows:

	December 31		
(in millions)	2006	2005	2004
Benefit obligation at December 31	$ 8	$ 7	$ 4
Funded status	$ (8)	$ (7)	$ (4)
Net periodic benefit cost	$ 1	$ 1	$ 1
Accrued benefit liability, as recognized in the consolidated balance sheet at December 31	$ (8)	$ (5)	$ (4)

During December 2006, we adopted the provisions of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – An Amendment of FASB Statements No. 87, 88, 106, and 132R* that required us to recognize in our consolidated balance sheet a liability for the underfunded status of our post-retirement health plan as of December 31, 2006. This liability, which is equal to the amount shown in the table above, is included as part of other long-term liabilities. The underfunded portion of $3 million, net of a deferred tax asset of $1 million, was recorded as a reduction to accumulated other comprehensive income. After 2006, changes in the funded status of the plan will be included in comprehensive income in the year during which the changes occur.

Unrecognized net actuarial loss is amortized to expense over the estimated average remaining service life of plan participants and prior service cost is amortized over a remaining life of four years. Including such amortization, the 2007 accrued benefit cost is expected to be approximately $2 million.

The following are assumptions used by us to determine our benefit obligation as of December 31 of each of the years presented:

	2006	2005	2004
Weighted average discount rate	6%	6%	6%
Health care cost trend rate assumed for the following year	9%	8.5%	9%
Rate to which the cost trend rate is assumed to decline (ultimate trend rate)	6%	6%	6%
Year that the rate reaches the ultimate trend rate	2013	2010	2010

Assumed health care cost trends have a significant effect on the amounts reported for health care plans. A one percentage point change in assumed health care cost trend rates would have a $1 million effect or less on both total service and interest cost and the post-retirement benefit obligation as of December 31, 2006.

Through 2016, projected benefit payments, which reflect expected future service, are not expected to exceed $800,000 in any one year and are less than $5 million in total.

Stock Incentive Plans

In November 2004, stockholders approved the 2004 Stock Incentive Plan under which 24 million shares of common stock were available for grants of stock awards. In May 2006, stockholders approved certain amendments to the 2004 Plan including increasing the shares available for grants of stock awards to 33.75 million shares. Prior to approval of the 2004 Plan, grants of stock awards were made pursuant to the 1998 Stock Incentive Plan. No further grants will be made under the 1998 Plan. Stock award grants are subject to certain limitations as specified in the Plan. The maximum term of stock awards is ten years under the 1998 Plan and seven years under the 2004 Plan. As a result of the May 12, 2006 distribution of the Hugoton Royalty Trust units (Note 9), appropriate antidilution adjustments were made to stock awards outstanding on that date.

Stock awards under the 2004 Plan include stock options, performance shares, restricted shares and unrestricted shares. The table below summarizes stock incentive compensation expense included in the consolidated financial statements and related amounts for each year:

	December 31		
(in millions)	2006	2005	2004
Non-cash stock option compensation expense	$ 53	$ –	$ –
Non-cash performance share and unrestricted share compensation expense	8	34	67
Non-cash restricted stock compensation expense	2	–	–
Cash-equivalent performance share expense	–	–	22
Related tax benefit recorded in income statement	23	12	34
Intrinsic value of stock option exercises	136	60	48
Excess income tax benefit on exercise of stock options (a)	50	21	18
Grant date fair value of stock options vested	24	78	20
Share-based liabilities at year-end	–	–	–

(a) Recorded as additional paid-in-capital

Included in stock option compensation expense in 2006 is $36 million related to options granted during May 2006, which were subject to accelerated vesting provisions upon retirement under employment agreements. Under SFAS No. 123R, stock option awards subject to such vesting provisions granted to retirement-eligible employees are expensed upon grant rather than over the expected vesting period (Note 6). In 2005 and prior, before adoption of SFAS No. 123R, performance share compensation was recorded at the vesting price, recognized ratably over the estimated vesting period or at actual vesting, if earlier or if the vesting period could not be reasonably assessed.

Stock Options

Stock options granted under the 2004 Plan generally vest and become exercisable ratably over a three-year period, and may include a provision for accelerated vesting when the common stock price reaches specified levels as determined by the Compensation Committee of the Board of Directors. Some stock options granted in 2006 vest only when the common stock reaches specified levels. There was a total of 19.8 million options outstanding under the 2004 Plan and the 1998 Plan at December 31, 2006, including 13.6 million that were exercisable at that date. Of the remaining options, 5.7 million vest over three years at a rate of one-third at each grant anniversary date, 0.3 million vested when the stock price closed above $52.50 in February 2007 and 0.2 million vest when the stock price closes at or above $57.50.

The following summarizes option activity and balances for the year ended December 31, 2006:

	Weighted-Average Exercise Price	Stock Options (in thousands)	Weighted-Average Remaining Term (in years)	Aggregate Intrinsic Value (in millions)
Balance at January 1, 2006	$ 23.82	20,202		
Grants	42.91	5,428		
Exercises	21.44	(5,699)		
Forfeitures	36.73	(106)		
Balance at December 31, 2006	29.66	19,825	5.4	$ 345
Exercisable at December 31, 2006	24.53	13,654	5.0	$ 308

As a result of options exercised in 2006, outstanding common stock increased by 2.5 million shares and stockholders' equity increased by $28 million.

Performance Shares

Performance shares granted under the 2004 Plan are subject to restrictions determined by the Compensation Committee of the Board of Directors and are subject to forfeiture if performance criteria are not met. Otherwise, holders of performance shares generally have all the voting, dividend and other rights of other common stockholders. To date, the performance criteria for all awards has been the achievement of specified increases in the common stock price above the market price at the grant date. The following summarizes performance share activity for each year:

	December 31		
(in thousands, except per share amounts)	2006	2005	2004
Shares granted to key employees (a)	150	414	2,576
Shares vested when common stock price reached specified levels	161	1,056	3,240
Weighted-average fair value of shares when granted (b)	$ 33.47	$ 36.98	$ 20.94
(in millions)			
Treasury stock purchases related to vested shares	$ 3	$ 14	$ 24

(a) Performance share grants in 2006 and 2005 were to key employees other than executive officers.

(b) Based on fair value in 2006 and intrinsic value at vesting in 2005 and 2004. Fair value was determined using a Monte Carlo simulation model. For further discussion of determination of fair value, see "Estimated Fair Value of Grants" below.

The following summarizes performance shares outstanding at December 31, 2006 by vesting price:

Vesting Price	Performance Shares
$ 53.17	1,250
55.00	72,437
65.00	71,438
	145,125

Performance share grants in 2006 and 2005 were to key employees other than executive officers. Prior to September 2004, most performance share awards were to executive officers. In September 2004, the Compensation Committee of the Board of Directors announced that it intended to restructure the Company's equity incentive program to discontinue the use of performance shares for executive officers named in the proxy and to provide that all future grants to the officers would be in the form of options or other stock appreciation shares. As a result, in October 2004, the

Compensation Committee of the Board of Directors amended the change in control performance share grant agreements to delete the provisions regarding the grant of performance shares for every $0.75 increment in the price of the common stock and to provide that, immediately prior to a change in control, these officers will receive a lump-sum cash payment equal to the value of 1,667,000 shares of common stock on the date of the change in control. A provision, providing that certain of these officers will also receive a total grant of 517,000 performance shares immediately prior to a change in control without regard to the price of our common stock, has been revised to provide that such payment will be in cash and not in shares of common stock. All amounts to be granted under these agreements will be adjusted for any future stock splits or other extraordinary transactions. If the named executive officers are subject to the 20% parachute excise tax, the Company will pay the officer an additional amount to "gross up" the payment so that the officer will receive the full amount due under the terms of the amended change in control grant agreement after payment of the excise tax.

Restricted Shares

In November 2006, we granted 1,047,000 restricted shares to key employees other than executive officers. These shares vest over three years, with one-third vesting at each grant anniversary date. Holders of restricted shares generally have all the voting, dividend and other rights of other common stockholders.

Nonemployee Director Awards

Nonemployee directors are each eligible to receive discretionary stock awards under the 2004 Plan covering up to 20,000 shares annually, as approved by the Corporate Governance and Nominating Committee and the Board of Directors. Nonemployee directors received automatic annual grants of unrestricted common shares that totaled 18,000 shares in 2004 under the 1998 Plan. Nonemployee directors received a total of 20,000 unrestricted shares in February 2007 and 2006 and 18,000 unrestricted shares in February 2005 under the 2004 Plan. In November 2004, nonemployee directors were granted a total of 88,000 stock options which vested in February 2005 when the common stock price reached specified levels. In November 2005, nonemployee directors received 96,000 stock options, 50% of which vested in 2005 when the common stock price closed above the target price of $45 and 50% which vested in 2006 when the common stock price closed above the target price of $50. In November 2006, nonemployee directors received 96,000 stock options, 50% of which vested when the stock closed above the target price of $52.50 in February 2007 and 50% which vest when the common stock price closes at or above the target price of $57.50.

Nonvested Stock Awards

The following summarizes the status of the nonvested stock options, performance shares and restricted shares as of December 31, 2006 and changes for the year ended December 31, 2006:

	Stock Options		Performance Shares		Restricted Shares	
(in thousands, except per share amounts)	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares
Nonvested at January 1, 2006	$ 11.50	2,874	$ 48.21	156	$ –	–
Vested	11.88	(2,025)	47.73	(161)	–	–
Grants	13.62	5,428	33.47	150	47.85	1,047
Forfeitures	12.52	(106)	–	–	–	–
Nonvested at December 31, 2006	$ 13.22	6,171	$ 33.51	145	$ 47.85	1,047

As of December 31, 2006, the remaining unrecognized compensation expense related to nonvested stock options was $49 million. Total deferred compensation at December 31, 2006 related to performance shares was $3 million and related to restricted shares was $46 million. For these nonvested stock awards at December 31, 2006, we estimate that stock incentive compensation for service periods after December 31, 2006 will be $47 million in 2007, $34 million in 2008 and $17 million in 2009. The weighted-average remaining vesting period is 1.8 years for stock options, 1.5 years for performance shares and 2.9 years for restricted shares.

Estimated Fair Value of Grants

Prior to adoption of SFAS No. 123R, we used the Black-Scholes option-pricing model to estimate the fair value of stock options and the intrinsic value method of valuing performance shares. Beginning January 1, 2006, we began using a lattice model to value stock option grants that time vest and a Monte Carlo simulation model to value performance shares and stock options that vest, or include a provision for accelerated vesting, when the common stock price reaches specified levels.

During 2006, we used both a trinomial lattice model and a Monte Carlo simulation model to determine the fair value of options granted, and we used a Monte Carlo simulation model to determine the fair value of performance shares granted. For restricted stock grants, the fair value is equal to the closing price of our common stock on the grant date.

The trinomial lattice model requires inputs for risk-free interest rate, dividend yield, volatility, contract term, average vesting period, post-vest turnover rate and suboptimal exercise factor. Both expected life and fair value are outputs of this model. The Monte Carlo simulation model requires inputs for risk-free interest rate, dividend yield, volatility, contract term, target vesting price, post-vest turnover rate and suboptimal exercise factor. The suboptimal exercise factor does not affect the valuation of the performance shares since ownership is transferred at vesting. Expected life, derived vesting period and fair value are outputs of this model.

The risk-free interest rate is based on the constant maturity nominal rates of U.S. Treasury securities with remaining lives throughout the contract term on the day of the grant. The dividend yield is the expected common stock annual dividend yield over the expected life of the option or performance share, expressed as a percentage of the stock price on the date of grant. The volatility factors are based on a combination of both the historical volatilities of our stock and the implied volatility of traded options on our common stock. Contract term is seven years. For options subject to time vesting, the average vesting period is two years, based on each grant vesting ratably over a three-year period. For options subject to vesting when the common stock reaches a specified price, the target vesting price is specified by the award. The post-vesting turnover rate is 3.5% and the suboptimal exercise factor is 1.6, and are both based on actual historical exercise activity. Estimates of fair value are not intended to predict actual future events or the value ultimately realized by certain employees who receive stock option grants, and subsequent events are not indicative of the reasonableness of the original fair value estimates.

We record stock incentive compensation only for awards expected to vest. During 2006, we estimated annual forfeitures using a rate of 2.5% for stock options, 0% for performance shares and 2.5% for restricted shares.

For the fair value of stock options awarded before 2006, we used the Black-Scholes option pricing model which utilizes assumptions different from those described above. The expected term was based on the historical exercise activity. The risk-free interest rate was the yield available on U.S. Treasury securities with a remaining term equal to the expected life of the option. The dividend yield was determined in the same manner as described above for the lattice model. The volatility factor was based on the historical volatility of our common stock over the expected life of the option.

During 2006, we granted 5.4 million options with an estimated total grant-date fair value of $74 million and a weighted-average fair value of $13.62 per option. The estimated fair value of stock-based awards not expected to vest was less than $1 million. During the year ended December 31, 2005, we granted 4.2 million options with a weighted-average fair value of $10.20. During the year ended December 31, 2004, we granted 16.2 million options with a weighted-average fair value of $5.34. Fair values were determined using the following assumptions:

	2006	2005	2004
Weighted-average expected term (years) . . .	4.4	3.5	3
Range of risk-free interest rates	4.3% - 5.2%	–	–
Weighted-average risk-free interest rates . . .	4.9%	4.0%	3.5%
Dividend yield	0.7%	0.7%	0.6%
Range of volatility	29% - 35%	–	–
Weighted-average volatility.	32%	35%	26%

13. Acquisitions

On February 28, 2006, we acquired proved and unproved properties in East Texas and Mississippi from Total E&P USA, Inc. for $300 million. The acquisition was funded by bank borrowings and is subject to typical post-closing adjustments.

On June 30, 2006, we acquired Peak Energy Resources, Inc., which operates gas-producing properties and owns unproved properties in the Barnett Shale in the Fort Worth Basin. The total purchase price is estimated to be $108 million, which was primarily funded by issuance of 2.555 million shares of common stock valued at $102 million (Note 9), $5 million cash for additional leasehold interests and $1 million cash for other transaction costs. After recording estimated deferred taxes of $37 million and other liabilities, the purchase price allocated to proved properties was $97 million and unproved properties was $54 million. The purchase price allocation is subject to adjustment, pending final determination of the tax bases and the fair value of certain assets acquired and liabilities assumed.

In March 2005, we traded nonoperated producing properties owned by us in the San Juan and Permian basins and in Alaska for producing properties owned by ConocoPhillips in the East Texas Freestone Trend, the San Juan Basin and the Permian Basin Goldsmith Field. The properties exchanged by each party had an approximate value of $74 million. We accounted for this transaction as an exchange of similar productive assets used in oil and gas producing activities, under APB Opinion No. 29 and SFAS No. 19, resulting in no gain or loss recognized on the exchange. We operate the properties that we received in this exchange.

To further establish our presence in the Barnett Shale in the Fort Worth Basin, we acquired Antero Resources Corporation on April 1, 2005. Antero Resources owned operated gas-producing properties and unproved properties in the Barnett Shale. In the transaction, we paid cash of $342 million, issued 13.3 million shares of our common stock, and issued warrants that expire March 2010 to purchase an additional 2.1 million shares of our common stock at $25.97 per share (as adjusted by antidilution adjustments resulting from the distribution of Hugoton Royalty Trust units (Note 9)). We also assumed $218 million of bank debt from Antero. The cash portion of the acquisition was funded with borrowings under our revolving credit facility. At closing, bank debt assumed from Antero Resources was repaid with borrowings under our revolving credit facility.

The following is the final calculation of the purchase price of Antero Resources Corporation and the allocation to assets and liabilities as of April 1, 2005. The fair value of consideration issued is determined as of January 10, 2005, the date the acquisition was announced.

(in millions)	
Consideration issued to Antero Resources stockholders:	
13.3 million shares of common stock (at fair value of $24.73 per share)	$ 330
Warrants to purchase 2.1 million shares of common stock at $25.97 per share (at fair value of $8.14 per warrant)	17
	347
Cash paid	342
Total purchase price	689
Fair value of liabilities assumed:	
Current liabilities	114
Long-term debt	218
Asset retirement obligation	4
Other long-term liabilities	11
Deferred income taxes	225
Total purchase price plus liabilities assumed	$ 1,261
Fair value of assets acquired:	
Cash and cash equivalents	$ 2
Other current assets	55
Proved properties	634
Unproved properties	180
Other property and equipment, primarily gathering and pipeline assets	35
Acquired gas gathering contracts	140
Goodwill (none deductible for income taxes)	215
Total fair value of assets acquired	$ 1,261

In May 2005, we acquired producing properties in East Texas and northwestern Louisiana from Plains Exploration & Production Company for an adjusted purchase price of $336 million. The acquisition was funded with borrowings under our revolving credit facility.

In June 2005, we entered an agreement with ExxonMobil Corporation to develop acreage in the northeastern portion of the Piceance Basin in northwest Colorado. Under the terms of the agreement, we will farm-in approximately 69,500 contiguous gross acres east of ExxonMobil's Piceance Creek Unit. We will operate and earn a 50% working interest ownership in the leasehold position by drilling four wells.

In July 2005, we acquired producing properties in the Permian Basin of West Texas and New Mexico from ExxonMobil Corporation for an adjusted purchase price of $200 million. The acquisition was funded with borrowings under our revolving credit facility.

In September 2005, we traded nonoperated producing properties in the Permian Basin of West Texas for producing properties owned by Occidental Petroleum in the Permian Basin of New Mexico. We accounted for this transaction as an exchange of nonmonetary assets in accordance with SFAS No. 153. This exchange resulted in the recognition of a $10 million gain.

In January 2004, we acquired producing properties located primarily in East Texas and northwestern Louisiana in three separate transactions totaling $243 million after adjustments of $6 million for net revenues, preferential right elections and other items from the effective date of the transaction. The acquisitions were funded with a portion of the proceeds from the sale of 4.9% senior notes in January 2004 (Note 3).

From February through April 2004, we purchased $223 million of properties located primarily in the Barnett Shale of North Texas and in the Arkoma Basin. Funding was provided by bank debt and cash flow from operations.

In two separate transactions during April 2004, we acquired predominantly oil-producing properties in the Permian Basin of West Texas and in the Powder River Basin of Wyoming from ExxonMobil Corporation for a total adjusted purchase price of $336 million. The acquisitions were funded with bank borrowings that were repaid with proceeds from the sale of common stock in May 2004 (Note 9).

In May 2004, we entered an agreement with ChevronTexaco Corporation to acquire properties for a stated purchase price of $1.1 billion. The acquisition closed in August 2004. After adjustments for net revenues from the January 1, 2004 effective date, preferential purchase right elections exercised in November and December 2004, and other typical closing adjustments, the adjusted purchase price was approximately $958 million. The acquisition was funded through existing bank credit facilities and the sale of common stock in May 2004. These properties expanded our operations in the Permian Basin and our Eastern and Mid-Continent regions, and added new coal bed methane properties in the Rocky Mountains and a new operating region in South Texas.

Two acquisitions in 2004 were purchases of corporations that primarily owned producing and nonproducing properties. After purchase accounting adjustments, including a $72 million step-up adjustment for deferred income taxes, the cost of all proved properties acquired in 2004 was $1.9 billion.

Acquisitions were recorded using the purchase method of accounting. The following presents our unaudited pro forma results of operations for 2005 and 2004, as if the 2005 Antero Resources acquisition, and the 2004 ChevronTexaco and ExxonMobil acquisitions were made at the beginning of each period. These pro forma results are not necessarily indicative of future results.

	Pro Forma (Unaudited) Year Ended December 31	
(in millions, except per share data)	2005	2004
Revenues	$ 3,555	$ 2,267
Net income	$ 1,155	$ 566
Earnings per common share:		
Basic	$ 3.19	$ 1.59
Diluted	$ 3.13	$ 1.58
Weighted average shares outstanding:		
Basic	361.7	355.5
Diluted	369.0	358.3

14. Quarterly Financial Data (Unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2006 and 2005:

	Quarter			
(in millions, except per share data)	1st	2nd	3rd	4th
2006				
Revenues	$ 1,215	$ 1,066	$ 1,096	$ 1,199
Gross profit (a)	$ 809	$ 651	$ 659	$ 742
Net income	$ 467	$ 597 (c)	$ 367	$ 429
Earnings per common share (b)				
Basic	$ 1.28	$ 1.64	$ 1.00	$ 1.17
Diluted	$ 1.26	$ 1.62	$ 0.99	$ 1.16
Average shares outstanding	363.9	363.8	365.9	366.0
2005				
Revenues	$ 629	$ 749	$ 964	$ 1,177
Gross profit (a)	$ 336	$ 420	$ 572	$ 790
Net income	$ 166	$ 220	$ 313	$ 453
Earnings per common share (b)				
Basic	$ 0.48	$ 0.61	$ 0.86	$ 1.25
Diluted	$ 0.47	$ 0.60	$ 0.85	$ 1.22
Average shares outstanding	347.4	361.0	361.9	363.4

(a) Operating income before general and administrative expense.

(b) Because quarterly earnings per share is based on the weighted average shares outstanding during the quarter, the sum of quarterly earnings per share may not equal earnings per share for the year.

(c) Included in second quarter net income is an after-tax gain on the distribution of Hugoton Royalty Trust units of $292 million (Note 9).

15. Supplementary Financial Information for Oil and Gas Producing Activities (Unaudited)

All of our operations are directly related to oil and gas producing activities located in the United States.

Costs Incurred Related to Oil and Gas Producing Activities

The following table summarizes costs incurred whether such costs are capitalized or expensed for financial reporting purposes:

(in millions)	2006	2005	2004
Acquisitions:			
Proved properties	$ 561	$ 1,710	$ 1,949(a)
Unproved properties – acquisition of corporation (b)	54	180	–
Unproved properties – other	171	92	50
Development (c)	2,022	1,341	570
Exploration	123	52	17
Asset retirement obligation accrued upon:			
Acquisition	7	24	48
Development (d)	64	29	12
Total Costs Incurred	$ 3,002	$ 3,428	$ 2,646

(a) Includes a deferred income tax step-up adjustment of $72 million.

(b) Represents a portion of the allocated purchase price of Peak Energy Resources, Inc. in 2006 and Antero Resources Corporation in 2005 (Note 13).

(c) Includes capitalized interest of $18 million in 2006, $6 million in 2005 and $3 million in 2004.

(d) Includes revisions of $36 million in 2006, $16 million in 2005 and $6 million in 2004.

Proved Reserves

Our proved oil and gas reserves have been estimated by independent petroleum engineers. Proved reserves are the estimated quantities that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors. Proved reserves exclude volumes deliverable to others under production payments.

Standardized Measure

The standardized measure of discounted future net cash flows and changes in such cash flows are prepared using assumptions required by the Financial Accounting Standards Board. Such assumptions include the use of year-end prices for oil and gas and year-end costs for estimated future development and production expenditures to produce year-end estimated proved reserves. Year-end prices are not adjusted for the effect of hedge derivatives. Discounted future net cash flows are calculated using a 10% rate. Estimated future income taxes are calculated by applying year-end statutory rates to future pre-tax net cash flows, less the tax basis of related assets and applicable tax credits.

As of December 31, 2003, estimated well abandonment costs, net of salvage values, are deducted from the standardized measure using year-end costs and discounted at the 10% rate. As required by SFAS No. 143, such abandonment costs are recorded as a liability on the consolidated balance sheet, using estimated values as of the projected abandonment date and discounted using a risk-adjusted rate at the time the well is drilled or acquired (Note 5).

The standardized measure does not represent management's estimate of our future cash flows or the value of proved oil and gas reserves. Probable and possible reserves, which may become proved in the future, are excluded from the calculations. Furthermore, year-end prices used to determine the standardized measure are influenced by seasonal demand and other factors and may not be the most representative in estimating future revenues or reserve data.

Proved Reserves

(in millions)	Gas (Mcf)	Natural Gas Liquids (Bbls)	Oil (Bbls)	Natural Gas Equivalents (Mcfe)
December 31, 2003	3,644.2	34.7	55.4	4,184.9
Revisions	(96.1)	(0.1)	3.0	(79.0)
Extensions, additions and discoveries	755.4	3.7	4.2	802.8
Production	(305.5)	(2.7)	(8.3)	(371.7)
Purchases in place	716.5	2.9	98.2	1,323.3
December 31, 2004	4,714.5	38.5	152.5	5,860.3
Revisions	4.0	5.3	12.1	108.5
Extensions, additions and discoveries	986.6	4.9	34.2	1,221.2
Production	(377.1)	(3.8)	(14.3)	(485.5)
Purchases in place	803.4	2.8	31.1	1,007.1
Sales in place	(45.8)	(0.3)	(6.9)	(89.4)
December 31, 2005	6,085.6	47.4	208.7	7,622.2
Revisions	(94.9)	1.8	0.1	(83.2)
Extensions, additions and discoveries	1,416.8	4.0	20.3	1,562.6
Production	(433.0)	(4.4)	(16.4)	(557.6)
Purchases in place	157.9	4.2	3.3	202.9
Sales in place (a)	(188.2)	–	(1.6)	(198.3)
December 31, 2006	6,944.2	53.0	214.4	8,548.6

(a) Includes effect of distribution of Hugoton Royalty Trust units (Note 9).

Proved Developed Reserves

(in millions)	Gas (Mcf)	Natural Gas Liquids (Bbls)	Oil (Bbls)	Natural Gas Equivalents (Mcfe)
December 31, 2003	2,651.3	28.2	47.9	3,107.7
December 31, 2004	3,252.7	30.0	134.4	4,239.1
December 31, 2005	4,033.1	36.5	168.5	5,262.9
December 31, 2006	4,481.6	40.1	167.3	5,725.9

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

	December 31		
(in millions)	2006	2005	2004
Future cash inflows	$ 51,477	$ 69,732	$ 34,027
Future costs:			
Production	(14,958)	(15,660)	(8,842)
Development	(4,260)	(3,175)	(1,580)
Future net cash flows before income tax	32,259	50,897	23,605
Future income tax	(10,251)	(16,823)	(7,366)
Future net cash flows	22,008	34,074	16,239
10% annual discount	(11,180)	(16,980)	(7,837)
Standardized measure (a)	$ 10,828	$ 17,094	$ 8,402

(a) Before income tax, the year-end standardized measure (or discounted present value of future net cash flows) was $16.2 billion in 2006, $25.8 billion for 2005 and $12.2 billion for 2004.

Changes in Standardized Measure of Discounted Future Net Cash Flows

(in millions)	2006	2005	2004
Standardized measure, January 1	$ 17,094	$ 8,402	$ 5,989
Revisions:			
Prices and costs	(10,687)	8,506	(20)
Quantity estimates	960	708	437
Accretion of discount	1,511	741	517
Future development costs	(2,479)	(2,167)	(797)
Income tax	4,090	(4,550)	(979)
Production rates and other	3	(2)	(2)
Net revisions	(6,602)	3,236	(844)
Extensions, additions and discoveries	2,248	3,723	1,384
Production	(3,629)	(2,744)	(1,512)
Development costs	1,917	1,128	484
Purchases in place (a)	396	3,527	2,901
Sales in place (b)	(596)	(178)	–
Net change	(6,266)	8,692	2,413
Standardized measure, December 31	$ 10,828 (c)	$ 17,094 (d)	$ 8,402 (e)

(a) Generally based on the year-end present value (at year-end prices and costs) plus the cash flow received from such properties during the year, rather than the estimated present value at the date of acquisition.

(b) Generally based on beginning of the year present value (at beginning of year prices and costs) less the cash flow received from such properties during the year, rather than the estimated present value at the date of sale. Included in 2006 is the effect of distribution of Hugoton Royalty Trust units (Note 9).

(c) The December 31, 2006 standardized measure includes a reduction of $29 million ($46 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2006 includes a liability of $307 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions as required by SFAS No. 143, as described above.

(d) The December 31, 2005 standardized measure includes a reduction of $22 million ($34 million before income tax) for estimated property abandonment costs. The consolidated balance sheet at December 31, 2005 includes a liability of $223 million for the same asset retirement obligation, which was calculated using different cost and present value assumptions as required by SFAS No. 143, as described above.

(e) The December 31, 2004 standardized measure includes a reduction of $15 million ($23 million before income tax) for estimated property abandonment costs.

Price and cost revisions are primarily the net result of changes in year-end prices, based on beginning of year reserve estimates. Quantity estimate revisions are primarily the result of the extended economic life of proved reserves and proved undeveloped reserve additions attributable to increased development activity.

Year-end average realized gas prices used in the estimation of proved reserves and calculation of the standardized measure were $5.46 for 2006, $9.26 for 2005, $5.69 for 2004 and $5.71 for 2003. Year-end average realized natural gas liquids prices were $31.96 for 2006, $36.33 for 2005, $28.24 for 2004 and $23.17 for 2003. Year-end average realized oil prices were $55.47 for 2006, $57.02 for 2005, $41.03 for 2004, and $30.55 for 2003.