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

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2006

or

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________________to__________________

Commission file number: **001-32395**

ConocoPhillips
(Exact name of registrant as specified in its charter)

Delaware	**01-0562944**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

600 North Dairy Ashford, Houston, TX 77079
(Address of principal executive offices) (Zip Code)

281-293-1000
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

The registrant had 1,645,769,817 shares of common stock, $.01 par value, outstanding at September 30, 2006.

CONOCOPHILLIPS

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

Consolidated Income Statement **ConocoPhillips**

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Revenues and Other Income				
Sales and other operating revenues *(1)*	$ **48,076**	48,745	**142,131**	128,184
Equity in earnings of affiliates	**1,196**	872	**3,320**	2,626
Other income	**313**	42	**537**	381
Total Revenues and Other Income	**49,585**	49,659	**145,988**	131,191
Costs and Expenses				
Purchased crude oil, natural gas and products	**30,551**	34,508	**93,454**	88,603
Production and operating expenses	**2,640**	1,982	**7,549**	6,081
Selling, general and administrative expenses	**650**	612	**1,826**	1,690
Exploration expenses	**197**	140	**443**	432
Depreciation, depletion and amortization	**2,137**	1,049	**5,282**	3,075
Impairments	**267**	—	**317**	31
Taxes other than income taxes *(1)*	**4,853**	4,606	**13,661**	13,758
Accretion on discounted liabilities	**74**	46	**207**	135
Interest and debt expense	**308**	122	**783**	387
Foreign currency transaction (gains) losses	**(50)**	34	**(10)**	52
Minority interests	**21**	6	**60**	21
Total Costs and Expenses	**41,648**	43,105	**123,572**	114,265
Income from continuing operations before income taxes	**7,937**	6,554	**22,416**	16,926
Provision for income taxes	**4,061**	2,750	**10,063**	7,068
Income From Continuing Operations	**3,876**	3,804	**12,353**	9,858
Loss from discontinued operations	**—**	(4)	**—**	(8)
Net Income	$ **3,876**	3,800	**12,353**	9,850
Income Per Share of Common Stock *(dollars)*				
Basic				
Continuing operations	$ **2.35**	2.73	**7.90**	7.06
Discontinued operations	**—**	—	**—**	(.01)
Net Income	$ **2.35**	2.73	**7.90**	7.05
Diluted				
Continuing operations	$ **2.31**	2.68	**7.78**	6.94
Discontinued operations	**—**	—	**—**	—
Net Income	$ **2.31**	2.68	**7.78**	6.94
Dividends Paid Per Share of Common Stock *(dollars)*	$ **.36**	.31	**1.08**	.87
Average Common Shares Outstanding *(in thousands)*				
Basic	**1,652,623**	1,393,943	**1,564,423**	1,396,180
Diluted	**1,675,839**	1,417,796	**1,587,892**	1,419,898
(1) Includes excise taxes on petroleum products sales:	*$* ***4,098***	*4,292*	***12,010***	*12,785*

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **ConocoPhillips**

	Millions of Dollars	
	September 30 2006	December 31 2005
Assets		
Cash and cash equivalents	$ **696**	2,214
Accounts and notes receivable (net of allowance of $85 million in 2006 and $72 million in 2005)	**12,064**	11,168
Accounts and notes receivable—related parties	**981**	772
Inventories	**6,198**	3,724
Prepaid expenses and other current assets	**4,661**	1,734
Total Current Assets	**24,600**	19,612
Investments and long-term receivables	**19,530**	15,726
Net properties, plants and equipment	**86,127**	54,669
Goodwill	**31,930**	15,323
Intangibles	**1,093**	1,116
Other assets	**443**	553
Total Assets	$ **163,723**	106,999
Liabilities		
Accounts payable	$ **13,528**	11,732
Accounts payable—related parties	**523**	535
Notes payable and long-term debt due within one year	**4,030**	1,758
Accrued income and other taxes	**5,416**	3,516
Employee benefit obligations	**1,184**	1,212
Other accruals	**2,673**	2,606
Total Current Liabilities	**27,354**	21,359
Long-term debt	**23,777**	10,758
Asset retirement obligations and accrued environmental costs	**5,583**	4,591
Deferred income taxes	**20,497**	11,439
Employee benefit obligations	**2,453**	2,463
Other liabilities and deferred credits	**2,362**	2,449
Total Liabilities	**82,026**	53,059
Minority Interests	**1,221**	1,209
Common Stockholders' Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2006—1,702,225,866 shares; 2005—1,455,861,340 shares)		
Par value	**17**	14
Capital in excess of par	**41,695**	26,754
Grantor trusts (at cost: 2006—45,876,265 shares; 2005—45,932,093 shares)	**(815)**	(778)
Treasury stock (at cost: 2006—10,579,784 shares; 2005—32,080,000 shares)	**(675)**	(1,924)
Accumulated other comprehensive income	**1,722**	814
Unearned employee compensation	**(153)**	(167)
Retained earnings	**38,685**	28,018
Total Common Stockholders' Equity	**80,476**	52,731
Total	$ **163,723**	106,999

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows **ConocoPhillips**

	Millions of Dollars Nine Months Ended September 30	
	2006	2005
Cash Flows From Operating Activities		
Income from continuing operations	$ **12,353**	9,858
Adjustments to reconcile income from continuing operations to net cash provided by continuing operations		
Non-working capital adjustments		
Depreciation, depletion and amortization	**5,282**	3,075
Impairments	**317**	31
Dry hole costs and leasehold impairments	**141**	211
Accretion on discounted liabilities	**207**	135
Deferred taxes	**273**	753
Undistributed equity earnings	**(1,007)**	(1,682)
Gain on asset dispositions	**(64)**	(264)
Other	**(296)**	1

Working capital adjustments		
Decrease in aggregate balance of accounts receivable sold	**—**	(480)
Decrease (increase) in other accounts and notes receivable	**172**	(1,269)
Increase in inventories	**(1,922)**	(1,275)
Increase in prepaid expenses and other current assets	**(669)**	(1,150)
Increase in accounts payable	**181**	2,748
Increase in taxes and other accruals	**911**	2,267
Net cash provided by continuing operations	**15,879**	12,959
Net cash used in discontinued operations	**—**	(6)
Net Cash Provided by Operating Activities	**15,879**	12,953
Cash Flows From Investing Activities		
Acquisition of Burlington Resources Inc.*	**(14,285)**	—
Capital expenditures and investments, including dry hole costs*	**(11,513)**	(8,573)
Proceeds from asset dispositions	**246**	608
Long-term advances/loans to affiliates and other	**(632)**	(188)
Collection of advances/loans to affiliates and other	**115**	159
Net cash used in continuing operations	**(26,069)**	(7,994)
Net cash used in discontinued operations	**—**	—
Net Cash Used in Investing Activities	**(26,069)**	(7,994)
Cash Flows From Financing Activities		
Issuance of debt	**15,263**	333
Repayment of debt	**(4,325)**	(1,845)
Issuance of company common stock	**145**	377
Repurchase of company common stock	**(675)**	(1,165)
Dividends paid on company common stock	**(1,684)**	(1,210)
Other	**(123)**	87
Net cash provided by (used in) continuing operations	**8,601**	(3,423)
Net Cash Provided by (Used in) Financing Activities	**8,601**	(3,423)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**71**	(120)
Net Change in Cash and Cash Equivalents	**(1,518)**	1,416
Cash and cash equivalents at beginning of period	**2,214**	1,387
Cash and Cash Equivalents at End of Period	**$ 696**	2,803

**Net of cash acquired.*
See Notes to Consolidated Financial Statements.

Note 1—Interim Financial Information

The interim-period financial information presented in the financial statements included in this report is unaudited and includes all known accruals and adjustments, in the opinion of management, necessary for a fair presentation of the consolidated financial position of ConocoPhillips and its results of operations and cash flows for such periods. All such adjustments are of a normal and recurring nature. The acquisition of Burlington Resources Inc. was reflected in our balance sheet beginning at March 31, 2006, and was reflected in our results of operations beginning April 1, 2006.

To enhance your understanding of these interim financial statements, see the consolidated financial statements and notes included in our 2005 Annual Report on Form 10-K.

Note 2—Accounting Policies

Revenue Recognition—Revenues associated with sales of crude oil, natural gas, natural gas liquids, petroleum and chemical products, and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry. Prior to April 1, 2006, revenues included the sales portion of transactions commonly called buy/sell contracts, in which physical commodity purchases and sales were contracted with the same counterparty to either obtain a different quality or grade of refinery feedstock supply, reposition a commodity (for example, where we entered into a contract with a counterparty to sell refined products or natural gas volumes at one location and purchase similar volumes at another location closer to our wholesale customer), or both “in contemplation” of one another.

Effective April 1, 2006, we implemented Emerging Issues Task Force (EITF) Issue No. 04-13, “Accounting for Purchases and Sales of Inventory with the Same Counterparty.” Issue No. 04-13 requires purchases and sales of inventory with the same counterparty and entered into “in contemplation” of one another to be combined and reported net (i.e., on the same income statement line). Exceptions to this are exchanges of finished goods for raw materials or work-in-progress within the same line of business, which are only reported net if the transaction lacks economic substance. The implementation of Issue No. 04-13 did not have a material impact on income from continuing operations or net income.

The table below shows the actual three months ended September 30, 2006, sales and other operating revenues, and purchased crude oil, natural gas and products under this new guidance, and the respective pro forma amounts included in this report had this new guidance been effective for all the periods prior to April 1, 2006.

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	Actual	Pro Forma	Pro Forma	
	2006	2005	**2006**	2005
Sales and other operating revenues	$ **48,076**	41,872	**135,474**	110,296
Purchased crude oil, natural gas and products	**30,551**	27,635	**86,797**	70,715

Revenues from the production of significant natural gas and crude oil properties, in which we have an interest with other producers, are recognized based on the actual volumes we sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, which are deemed to be non-recoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally not significant. Revenues associated with royalty fees from licensed technology are recorded based either upon volumes produced by the licensee or upon the successful completion of all substantive performance requirements related to the installation of licensed technology.

Stock-Based Compensation—Effective January 1, 2003, we voluntarily adopted the fair-value accounting method prescribed by Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation." We used the prospective transition method, applying the fair-value accounting method and recognizing compensation expense equal to the fair-market value on the grant date for all stock options granted or modified after December 31, 2002.

Employee stock options granted prior to 2003 were accounted for under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and related Interpretations; however, by the end of 2005, all of these awards had vested. Because the exercise price of our employee stock options equaled the market price of the underlying stock on the date of grant, generally no compensation expense was recognized under APB Opinion No. 25. The following table displays 2005 pro forma information as if provisions of SFAS No. 123 had been applied to all employee stock options granted:

	Millions of Dollars	
	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
Net income, as reported	$ 3,800	9,850
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	71	144
Deduct: Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of related tax effects	(72)	(146)
Pro forma net income	$ 3,799	9,848
Earnings per share:		
Basic—as reported	$ 2.73	7.05
Basic—pro forma	2.73	7.05
Diluted—as reported	2.68	6.94
Diluted—pro forma	2.68	6.94

Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), "Share-Based Payment," (SFAS No. 123(R)). For information about our adoption of this new accounting standard, see Note 3—Changes in Accounting Principles.

Note 3—Changes in Accounting Principles

At its September 2005 meeting, the EITF reached a consensus on Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," which requires purchases and sales of inventory with the same counterparty and entered into "in contemplation" of one another to be combined and reported net. We adopted Issue No. 04-13 effective April 1, 2006. For additional information, see the Revenue Recognition section of Note 2—Accounting Policies.

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), which supercedes APB Opinion No. 25, "Accounting for Stock Issued to Employees," and replaces SFAS No. 123, "Accounting for Stock-Based Compensation." SFAS No. 123(R), which was effective January 1, 2006, prescribes the accounting for a wide range of share-based compensation arrangements, including options, restricted share plans, performance-based awards, share appreciation rights, and employee share purchase plans, and generally requires the fair value of share-based awards to be expensed. We adopted SFAS No. 123(R) on January 1, 2006, using the modified-prospective transition method provided under the Statement.

SFAS No. 123(R) permits the use of either the accelerated method or the straight-line method of recognizing expense for share-based awards subject to graded vesting (i.e., when portions of the award vest at different dates throughout the vesting period). In the past, we have used the accelerated recognition method for these awards, but concurrent with our adoption of SFAS No. 123(R), we elected to use the straight-line recognition method to account for new awards granted with graded vesting provisions.

Generally, our stock-based compensation programs provide accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. For awards granted prior to January 1, 2006, we recognize expense over the period of time during which the employee earns the award, accelerating the recognition of expense only when an employee actually retires.

For stock-based compensation awards granted after December 31, 2005, our adoption of SFAS No. 123(R) requires us to recognize expense over the shorter of the service period (i.e., the stated period of time required to earn the award), or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. This change in recognition method shortens the period over which we recognize expense for most of our stock-based awards granted to employees who already are, or soon will be, eligible for retirement.

During the first nine months of 2006, the company granted approximately 3.2 million restricted stock units, with an average fair value of $58.51 per unit, under the 2004 Omnibus Stock and Performance Incentive Plan, while restrictions lapsed in accordance with the terms of the plan on approximately 300,000 restricted stock units.

Also during the first nine months of 2006, the company granted approximately 1.8 million stock options, primarily under the 2004 Omnibus Stock and Performance Incentive Plan, with a weighted-average exercise price of $59.33 and a weighted-average fair value of $16.17 per option. The fair values were calculated using the Black-Scholes-Merton option-pricing model, with the following weighted-average assumptions: a risk-free interest rate of 4.63 percent, an expected dividend yield of 2.50 percent, a volatility factor of 26.1 percent and an expected life of 7.18 years. As of September 30, 2006, approximately 2,340 of these stock options were exercisable.

In addition to the above stock option activity, on March 31, 2006, in exchange for outstanding Burlington Resources Inc. stock options, the company granted approximately 3.6 million vested stock options, with an

average exercise price of $23.40 per share, and approximately 1.3 million non-vested stock options, with an average exercise price of $62.99 per share. The aggregate fair value of these options, as calculated with the Black-Scholes-Merton option-pricing model, was approximately $164 million.

During the first nine months of 2006, approximately 6.0 million stock options were exercised with an average exercise price of $24.11 per option, and approximately 6.6 million options became eligible for exercise.

Due in part to our having fully adopted the fair-value accounting method prescribed by SFAS No. 123 on January 1, 2003, the adoption of SFAS No. 123(R) did not have a material impact on our 2006 financial statements, nor do we expect it to have a material impact on our future financial statements.

In November 2004, the FASB issued SFAS No. 151, “Inventory Costs, an amendment of ARB No. 43, Chapter 4.” This Statement clarifies items such as abnormal amounts of idle facility expense, freight, handling costs, and wasted material (spoilage) be recognized as current-period charges. In addition, the Statement requires the allocation of fixed production overheads to the costs of conversion based on the normal capacity of the production facilities. We adopted this Statement effective January 1, 2006. The adoption did not have a material impact on our financial statements.

Note 4—Acquisition of Burlington Resources Inc.

On March 31, 2006, we completed the $33.9 billion acquisition of Burlington Resources Inc., an independent exploration and production company that held a substantial position in North American natural gas proved reserves, production and exploratory acreage. We issued approximately 270.4 million shares of our common stock and paid approximately $17.5 billion in cash. We acquired $3.2 billion in cash and assumed $4.3 billion of debt from Burlington Resources in the acquisition, including recognition of an increase of $406 million to record the debt at its fair value. Results of operations attributable to Burlington Resources were included in our consolidated income statement beginning in the second quarter of 2006.

The acquisition of Burlington Resources added approximately 2 billion barrels of oil equivalent to our proved reserves.

The primary reasons for the acquisition and the principal factors contributing to a purchase price resulting in the recognition of goodwill were expanded growth opportunities in North American natural gas exploration and development, cost savings from the elimination of duplicate activities, and the sharing of best practices in the operations of both companies.

The $33.9 billion purchase price was based on Burlington Resources shareholders receiving $46.50 in cash and 0.7214 shares of ConocoPhillips common stock for each Burlington Resources share owned. ConocoPhillips issued approximately 270.4 million shares of common stock and approximately 3.6 million vested employee stock options in exchange for 374.8 million shares of Burlington Resources common stock and 2.5 million Burlington Resources vested stock options. The ConocoPhillips common stock was valued at $59.85 per share, which was the weighted-average price of ConocoPhillips common stock for a five-day period beginning two available trading days before the public announcement of the transaction on the evening of December 12, 2005. The Burlington Resources vested stock options, whose fair value was determined using the Black-Scholes-Merton option-pricing model, were exchanged for ConocoPhillips stock options valued at $146 million. Estimated transaction-related costs were $56 million.

Also included in the acquisition was the replacement of 0.9 million non-vested Burlington Resources stock options and 0.4 million shares of non-vested restricted stock with 1.3 million non-vested ConocoPhillips stock options and 0.5 million non-vested ConocoPhillips restricted stock. In addition, 1.2 million

Burlington Resources shares of common stock held by a consolidated grantor trust, related to a deferred compensation plan, were converted into 0.9 million ConocoPhillips common shares and were recorded as a reduction of common stockholders’ equity.

The preliminary allocation of the purchase price to specific assets and liabilities was based, in part, upon a preliminary outside appraisal of the fair value of Burlington Resources assets. Over the next few months, we expect to receive the final outside appraisal of the long-lived assets and conclude the fair value determination of all other Burlington Resources assets and liabilities. The following table summarizes, based on the preliminary purchase price allocation described above, the fair values of the assets acquired and liabilities assumed as of March 31, 2006:

	Millions of Dollars
Cash and cash equivalents	$ 3,238
Accounts and notes receivable	1,268
Inventories	241
Prepaid expenses and other current assets	148
Investments and long-term receivables	354
Properties, plants and equipment	28,546
Goodwill	16,705
Intangibles	107
Other assets	50
Total assets	$ 50,657
Accounts payable	$ 1,497
Notes payable and long-term debt due within one year	1,009
Accrued income and other taxes	952
Employee benefit obligations—current	225
Other accruals	68
Long-term debt	3,330
Asset retirement obligations	879
Accrued environmental costs	69
Deferred income taxes	8,007
Employee benefit obligations	334
Other liabilities and deferred credits	395
Common stockholders' equity	33,892
Total liabilities and equity	$ 50,657

We assigned all of the Burlington Resources goodwill to the Worldwide Exploration and Production reporting unit. Of the $16,705 million of goodwill, $8,283 million relates to net deferred tax liabilities arising from differences between the allocated financial bases and deductible tax bases of the acquired assets. None of the goodwill is deductible for tax purposes.

Goodwill recorded in the acquisition is not subject to amortization, but will be tested periodically for impairment as required by SFAS No. 142, "Goodwill and Other Intangible Assets."

The following table presents actual results for the three-month period ended September 30, 2006, and the respective pro forma information as if the acquisition had occurred at the beginning of each year presented.

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	Actual	Pro Forma	Pro Forma	
	2006	2005	**2006**	2005
Sales and other operating revenues	$ **48,076**	50,348	**144,036**	132,699
Income from continuing operations	**3,876**	4,157	**12,747**	10,428
Net income	**3,876**	4,153	**12,747**	10,420
Income from continuing operations per share of common stock				
Basic	**2.35**	2.50	**7.71**	6.26
Diluted	**2.31**	2.46	**7.60**	6.16
Net income per share of common stock				
Basic	**2.35**	2.50	**7.71**	6.25
Diluted	**2.31**	2.46	**7.60**	6.16

The unaudited pro forma information does not reflect any anticipated synergies that might be achieved from combining the operations. The pro forma information is not intended to reflect the actual results that would have occurred if the companies had been combined during the periods presented, nor is it intended to be indicative of the results of operations that may be achieved by ConocoPhillips in the future.

The pro forma adjustments include estimates and assumptions based on currently available information. We believe the estimates and assumptions are reasonable, and the significant effects of the transactions are properly reflected. However, actual results may differ materially from this pro forma financial information.

Note 5—Restructuring

As a result of the acquisition of Burlington Resources Inc., we implemented a restructuring program in March 2006 to capture the synergies of combining the two companies. Under this program, which is expected to be completed by the end of March 2008, we recorded accruals totaling $201 million for employee severance payments, site closings, incremental pension benefit costs associated with the workforce reductions, and employee relocations. Approximately 600 positions have been identified for elimination, most of which are in the United States. Of the total accrual, $196 million is reflected in the Burlington

Resources purchase price allocation as an assumed liability, and $5 million ($3 million after-tax) related to ConocoPhillips is reflected in selling, general and administrative expenses. Included in the total accruals of $201 million is $12 million related to pension benefits to be paid in conjunction with other retirement benefits over a number of future years. Benefit payments of $87 million related to the non-pension accrual of $189 million were made through September 2006, resulting in an ending liability balance of $102 million. Of this amount, $75 million is expected to be extinguished within one year.

Note 6—Variable Interest Entities (VIEs)

In June 2006, ConocoPhillips acquired a 24 percent interest in West2East Pipeline LLC, a company holding a 100 percent interest in Rockies Express Pipeline LLC. Rockies Express plans to construct a 1,633-mile natural gas pipeline from the Cheyenne Hub in Weld County, Colorado, to the Clarington Hub in eastern Ohio. Rockies Express is a VIE because a third party other than ConocoPhillips and our partners holds a significant voting interest in the company until project completion. We currently participate in the management committee of Rockies Express as a non-voting member. We are not the primary beneficiary of Rockies Express. We use the equity method of accounting for our investment in West2East Pipeline. At September 30, 2006, we had made no capital investment in West2East Pipeline.

In 2005, ConocoPhillips and OAO LUKOIL (LUKOIL) created the OOO Naryanmarneftegaz (NMNG) joint venture to develop resources in the Timan-Pechora region of Russia. The NMNG joint venture is a VIE because we and our related party, LUKOIL, have disproportionate interests. We have a 30 percent ownership interest with a 50 percent governance interest in the joint venture. We are not the primary beneficiary of the VIE. At September 30, 2006, the book value of our investment in the venture was $869 million.

Note 7—Inventories

Inventories consisted of the following:

	Millions of Dollars	
	September 30 2006	December 31 2005
Crude oil and petroleum products	**$ 5,416**	3,183
Materials, supplies and other	**782**	541
	$ 6,198	3,724

Inventories valued on the last-in, first-out (LIFO) basis totaled $5,190 million and $3,019 million at September 30, 2006, and December 31, 2005, respectively. The remainder of our inventories is valued under various methods, including first-in, first-out and weighted average. The excess of current replacement cost over LIFO cost of inventories amounted to $4,046 million and $3,958 million at September 30, 2006, and December 31, 2005, respectively.

Note 8—Assets Held for Sale

In April 2006, we announced the commencement of an asset rationalization program to evaluate our asset base to identify those assets that may no longer fit into our strategic plans or those that could bring more value by being monetized in the near term. During the third quarter of 2006, certain assets included in this program met the held-for-sale criteria of SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Accordingly, in the third quarter of 2006, on those assets required, we reduced the carrying value of the assets held for sale to estimated fair value less costs to sell, resulting in an impairment of $266 million before-tax ($253 million after-tax). Further, we ceased depreciation, depletion and amortization of the properties, plants, and equipment associated with these assets from the dates they were classified as held for sale.

At September 30, 2006, we reclassified $2,385 million from non-current assets into the "Prepaid expenses and other current assets" line of our consolidated balance sheet and we reclassified $593 million from non-current liabilities to current liabilities, consisting of $323 million into "Accrued income and other taxes" and $270 million into "Other accruals."

The major classes of non-current assets and non-current liabilities held for sale at September 30, 2006, reclassified to current were:

	Millions of Dollars
Assets	
Investments and long-term receivables	$ 172
Net properties, plants and equipment	1,926
Goodwill	160
Intangibles	16
Other assets	111
Total assets reclassified	$ 2,385
Exploration and Production	$ 1,577
Refining and Marketing	808
	$ 2,385
Liabilities	
Asset retirement obligations and accrued environmental costs	$ 251
Deferred income taxes	323

Employee benefit obligations		2
Other liabilities and deferred credits		17
Total liabilities reclassified	$	593
Exploration and Production	$	514
Refining and Marketing		79
	$	593

Note 9—Investments and Long-Term Receivables

LUKOIL

We increased our ownership interest in LUKOIL to 19.0 percent at September 30, 2006, based on 850.6 million shares authorized and issued. For financial reporting under U.S. generally accepted accounting principles, certain treasury shares held by LUKOIL subsidiaries are not considered outstanding for determining our equity-method ownership interest in LUKOIL. Excluding these treasury shares (20.2 million of the 22.8 million treasury shares, based on latest available public data) from the denominator of our ownership calculation, our equity-method ownership interest at September 30, 2006, was 19.5 percent.

At September 30, 2006, the book value of our investment in ordinary shares of LUKOIL was $8,532 million. Our share of the net assets of LUKOIL was estimated to be $6,315 million. This basis difference of $2,217 million is primarily being amortized on a unit-of-production basis. On September 30, 2006, the closing price of LUKOIL shares on the London Stock Exchange was $75.50 per share, making the total market value of our LUKOIL investment $12,202 million.

Loans to Affiliated Companies

As part of our normal ongoing business operations and consistent with normal industry practice, we invest and enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements. Included in such activity are loans made to certain affiliated companies. Significant loans to affiliated companies at September 30, 2006, included the following:

- $457 million in loan financing, including accrued interest, to Freeport LNG for the construction of a liquefied natural gas (LNG) regasification facility. We expect to provide total financing of approximately $630 million for the construction of the facility.

- $167 million in loan financing, including accrued interest, to Varandey Terminal Company associated with the costs to expand an existing crude oil terminal operated by LUKOIL. Based on the current estimate from the operator, we assess our total obligation for the terminal expansion to be approximately $350 million at current exchange rates.

- $336 million of project financing, including accrued interest, to Qatargas 3, an integrated project to produce and liquefy natural gas from Qatar’s North field. Our maximum exposure to this financing structure is $1.2 billion.

Note 10—Properties, Plants and Equipment

Properties, plants and equipment included the following at September 30, 2006, and December 31, 2005:

	Millions of Dollars					
	September 30, 2006			December 31, 2005		
	Gross PP&E	**Accum. DD&A**	**Net PP&E**	Gross PP&E	Accum. DD&A	Net PP&E
Exploration and Production (E&P)	**$ 87,126**	**19,970**	**67,156**	53,907	16,200	37,707
Midstream	**327**	**150**	**177**	322	128	194
Refining and Marketing (R&M)	**22,537**	**5,282**	**17,255**	20,046	4,777	15,269
LUKOIL Investment	**—**	**—**	**—**	—	—	—
Chemicals	**—**	**—**	**—**	—	—	—
Emerging Businesses	**931**	**85**	**846**	865	61	804
Corporate and Other	**1,204**	**511**	**693**	1,192	497	695
	$ 112,125	**25,998**	**86,127**	76,332	21,663	54,669

Suspended Wells

The following table reflects the net changes in suspended exploratory well costs during the first nine months of 2006:

	Millions of Dollars **Nine Months Ended September 30, 2006**
Beginning balance at January 1	**$ 339**
Additions pending the determination of proved reserves	**259**
Reclassifications to proved properties	**(11)**
Charged to dry hole expense	**(5)**
Ending balance at September 30	**582**

The following table provides an aging of suspended well balances at September 30, 2006, and December 31, 2005:

	Millions of Dollars		
	September 30 2006		December 31 2005
Exploratory well costs capitalized for a period of one year or less	$	**362**	183
Exploratory well costs capitalized for a period greater than one year		**220**	156
Ending balance	$	**582**	339
Number of projects with exploratory well costs capitalized for a period greater than one year		**20**	15

The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling, as of September 30, 2006:

	Millions of Dollars						
			Suspended Since				
Project		Total	2005	2004	2003	2002	2001
Alpine satellite—Alaska *(2)*	$	21	—	—	—	21	—
Kashagan—Republic of Kazakhstan *(1)*		18	—	—	9	—	9
Kairan—Republic of Kazakhstan *(1)*		13	—	13	—	—	—
Aktote—Republic of Kazakhstan *(2)*		19	—	7	12	—	—
Gumusut—Malaysia *(2)*		30	6	11	13	—	—
Malikai—Malaysia *(2)*		10	—	10	—	—	—
Ubah—Malaysia *(1)*		13	13	—	—	—	—
Plataforma Deltana—Venezuela *(2)*		21	6	15	—	—	—
Hejre—Denmark *(2)*		22	14	—	—	—	8
Eleven projects of less than $10 million each *(1)(2)*		53	24	1	19	9	—
Total of 20 projects	$	220	63	57	53	30	17

(1)Additional appraisal wells planned.
(2)Appraisal drilling complete; costs being incurred to assess development.

Note 11—Goodwill

Changes in the carrying amount of goodwill were as follows:

	Millions of Dollars			
		E&P	R&M	Total
Balance at December 31, 2005	$	11,423	3,900	15,323
Acquired (Burlington Resources)		**16,705**	**—**	**16,705**
Acquired (Wilhelmshaven refinery)		**—**	**224**	**224**
Goodwill allocated to assets held for sale		**(43)**	**(117)**	**(160)**
Impairment of goodwill		**—**	**(60)**	**(60)**
Tax and other adjustments		**(103)**	**1**	**(102)**
Balance at September 30, 2006	**$**	**27,982**	**3,948***	**31,930**

**Consists of two reporting units: Worldwide Refining ($2,216) and Worldwide Marketing ($1,732).*

On March 31, 2006, we acquired Burlington Resources Inc., an independent exploration and production company. As a result of this acquisition, we recorded goodwill of $16,705 million, all of which was aligned with our E&P segment. See Note 4—Acquisition of Burlington Resources Inc., for additional information.

On February 28, 2006, we acquired the Wilhelmshaven refinery, located in Wilhelmshaven, Germany. The purchase included the refinery, a marine terminal, rail and truck loading facilities and a tank farm, as well as another entity that provides commercial and administrative support to the refinery. As a result of this acquisition, we recorded goodwill of $224 million, all of which was aligned with our R&M segment. The allocation of the purchase price to specific assets and liabilities was based on a combination of an outside appraiser's valuation for fixed assets and an internal estimate of the fair values of the various other assets and liabilities acquired. We are finalizing the fair value of certain liabilities. Over the next few months, the company expects to finalize the allocation of the purchase price to the specific assets and liabilities acquired and the calculations of deferred tax liabilities and goodwill.

Note 12—Impairments

In the third quarter of 2006, we recorded impairments of $266 million associated with planned asset dispositions in our E&P and R&M segments, comprised of properties, plants and equipment ($136 million), trademark intangibles ($70 million), and goodwill ($60 million). Impairments for the nine-month period of 2006 included a property impairment of $40 million recorded as a result of our decision to withdraw an application for a license under the federal Deepwater Port Act, associated with a proposed LNG regasification terminal located offshore Alabama. We also impaired properties located offshore Australia due to increased accrued dismantlement and removal costs. In the nine-month period of 2005, we recorded property impairments related to planned asset dispositions in our E&P and Midstream segments. The impairments by segment were:

	Three Months Ended September 30 (Millions of Dollars)		Nine Months Ended September 30	
	2006	2005	**2006**	2005
E&P	**$ 7**	—	**57**	1
Midstream	**—**	—	**—**	30
R&M	**260**	—	**260**	—
	$ 267	—	**317**	31

Note 13—Debt

Our debt balance at September 30, 2006, was $27.8 billion, compared with a debt balance of $12.5 billion at year-end 2005, $32.2 billion at March 31, 2006, and $29.5 billion at June 30, 2006. The increase in the first quarter of 2006 reflects debt issuances of $15.3 billion related to the acquisition of Burlington Resources Inc. and the assumption of $4.3 billion of Burlington Resources debt, including the recognition of an increase of $406 million to record the debt at its fair value. These increases in the first quarter of 2006 were partly offset by debt reductions during the second and third quarters of 2006.

In March 2006, we closed on two $7.5 billion bridge facilities with a group of five banks to help fund the Burlington Resources acquisition. These bridge financings were both 364-day loan facilities with pricing and terms similar to our existing revolving credit facilities. These facilities were fully drawn in the funding of the acquisition.

In April 2006, we entered into and funded a $5 billion five-year term loan, closed on a $2.5 billion five-year revolving credit facility, increased the ConocoPhillips commercial paper program to $7.5 billion, and issued $3 billion of debt securities. The term loan and new credit facility were executed with a group of 36 banks with terms and pricing provisions similar to our other existing revolving credit facilities. The proceeds from the term loan, debt securities and issuances of commercial paper, together with our cash balances and cash provided from operations, were used to repay the $15 billion bridge facilities during the second and third quarters of 2006.

The $3 billion of debt securities were issued in early April 2006. Of this issuance, $1 billion of Floating Rate Notes due April 11, 2007, were issued by ConocoPhillips, and $1.25 billion of Floating Rate Notes due April 9, 2009, and $750 million of 5.50% Notes due 2013, were issued by ConocoPhillips Australia Funding Company, a wholly owned subsidiary. ConocoPhillips guarantees the obligations of ConocoPhillips Australia Funding Company.

At September 30, 2006, we had two revolving credit facilities totaling $5 billion. Expiration dates for both facilities were extended one year in the third quarter of 2006 to October 2011. We also have a $2.5 billion five-year revolving credit facility we entered into in April 2006. These facilities may be used as direct bank borrowings, as support for the ConocoPhillips $7.5 billion commercial paper program, as support for the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, or as support for issuances of letters of credit totaling up to $750 million. The facilities are broadly syndicated among financial institutions and do not contain any material adverse change provisions or covenants requiring maintenance of specified financial ratios or ratings. The credit facilities contain a cross-default provision relating to our, or any of our consolidated subsidiaries', failure to pay principal or interest on other debt obligations of $200 million or more. At September 30, 2006, and December 31, 2005, we had no outstanding borrowings under these credit facilities, but $41 million and $62 million, respectively, in letters of credit had been issued. Under both commercial paper programs there was $3,470 million of commercial paper outstanding at September 30, 2006, compared with $32 million at December 31, 2005. The commercial paper increase resulted from efforts to reduce the bridge facilities discussed above.

The following table reflects Burlington Resources debt assumed in the acquisition, including increases to record the debt at fair value (see Note 4—Acquisition of Burlington Resources Inc., for additional information about the acquisition). Balances at the March 31, 2006, acquisition date were:

	Millions of Dollars
5.60% Notes due 2006	$ 500
6.60% Notes due 2007 *(1)*	129
5.70% Notes due 2007	350
9 7/8% Debentures due 2010	150
6.50% Notes due 2011	500
6.68% Notes due 2011	400
6.40% Notes due 2011	178
7 5/8% Debentures due 2013	100
9 1/8% Debentures due 2021	150
7.65% Debentures due 2023	88
8.20% Debentures due 2025	150
6 7/8% Debentures due 2026	67
7 3/8% Debentures due 2029	92
7.20% Notes due 2031	575
7.40% Notes due 2031	500
Capital lease	4
Unamortized premiums and discounts	406
Total debt assumed	4,339
Notes payable and long-term debt due within one year	(1,009)
Long-term debt assumed	$ 3,330

(1) Notes are denominated in Canadian dollars and reported in U.S. dollars.

Maturities at March 31, 2006, on Burlington Resources debt assumed, inclusive of net unamortized premiums and discounts, for the remainder of 2006 through 2010 were: $650 million, $377 million, $27 million, $25 million and $175 million, respectively.

The amortization of the fair-value adjustment will result in the above fixed-rate notes having a weighted-average annual effective interest rate of 5.64 percent.

In October 2006, we redeemed our $1.25 billion 5.45% Notes upon their maturity and redeemed our $500 million 5.60% Notes due December 2006, and our $350 million 5.70% Notes due March 2007, at a premium of $1 million, plus accrued interest. In order to finance the maturity and call of the above notes, ConocoPhillips Canada Funding Company I, a wholly owned subsidiary, issued $1.25 billion of 5.625% Notes due 2016, and ConocoPhillips Canada Funding Company II, a wholly owned subsidiary, issued $500 million of 5.95% Notes due 2036, and $350 million of 5.30% Notes due 2012. ConocoPhillips and ConocoPhillips Company guarantee the obligations of ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II.

In May 2006, we redeemed our $240 million 7.625% Notes upon their maturity and redeemed our $129 million 6.60% Notes due in 2007 at a premium of $4 million, plus accrued interest.

Note 14—Contingencies and Commitments

In the case of all known contingencies, we accrue a liability when the loss is probable and the amount is reasonably estimable. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries.

Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates that are particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during administrative and litigation processes.

Environmental—We are subject to federal, state and local environmental laws and regulations. These may result in obligations to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various sites. When we prepare our financial statements, we record accruals for environmental liabilities based on management's best estimates, using all information that is available at the time. We measure estimates and base liabilities on currently available facts, existing technology, and presently enacted laws and regulations, taking into consideration the likely effects of societal and economic factors. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, the cleanup experience of other companies, and data released by the U.S. Environmental Protection Agency (EPA) or other organizations. We also consider unasserted claims in our determination of environmental liabilities and we accrue them in the period they become both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for state sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all of the cleanup costs related to any site at which we have been designated as a potentially responsible party. If we were solely responsible, the costs, in some cases, could be material to our, or one of our segments', results of operations, capital resources or liquidity. However, settlements and costs incurred in matters that previously have been resolved have not been material to our results of operations or financial condition. We have been successful

to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportionate share, we consider this inability in estimating our potential liability and adjust our accruals accordingly.

As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit and some of the indemnifications are subject to dollar and time limits. We have not recorded accruals for any potential contingent liabilities that we expect to be funded by the prior owners under these indemnifications.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except for those assumed in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable that future costs will be incurred and these costs can be reasonably estimated. At September 30, 2006, our balance sheet included a total environmental accrual of $1,034 million, compared with $989 million at December 31, 2005. We expect to incur the majority of these expenditures within the next 30 years. In the future, we may be involved in additional environmental assessments, cleanups and proceedings.

Legal Proceedings—We apply our knowledge, experience, and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings involving us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases which have been scheduled for trial, as well as the pace of settlement discussions in individual matters. Based on our professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, we believe there is only a remote likelihood that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our financial statements.

Other Contingencies—We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at September 30, 2006, we had performance obligations secured by letters of credit of $1,039 million (of which $41 million was issued under the provisions of our revolving credit facilities, and the remainder was issued as direct bank letters of credit) and various purchase commitments for materials, supplies, services, and items of permanent investment incident to the ordinary conduct of business.

Note 15—Guarantees

At September 30, 2006, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted, we have not recognized a liability either because the guarantees were issued prior to December 31, 2002, or because the fair value of the obligation is immaterial.

Construction Completion Guarantees

- In June 2006, we issued a guarantee for 24 percent of the $2.0 billion in credit facilities of Rockies Express Pipeline LLC, which will be used to construct a natural gas pipeline across a portion of the United States. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $480 million, which could become payable if the credit facility is fully utilized and Rockies Express Pipeline LLC fails to meet its obligations under the credit agreement. It is anticipated that construction completion will be achieved mid-2009, and refinancing will take place at that time, making the debt non-recourse. At September 30, 2006, the carrying value of the guarantee to third-party lenders was $11 million. For additional information, see Note 6—Variable Interest Entities (VIEs).

- In December 2005, we issued a construction completion guarantee for 30 percent of the $4.0 billion in loan facilities of Qatargas 3, which will be used to construct an LNG train in Qatar. Of the $4.0 billion in loan facilities, ConocoPhillips has committed to provide $1.2 billion. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $850 million, which could become payable if the full debt financing is utilized and completion of the Qatargas 3 project is not achieved. The project financing will be non-recourse upon certified completion, which is expected by December 31, 2009. At September 30, 2006, the carrying value of the guarantee to the third-party lenders was $11 million. For additional information, see Note 9—Investments and Long-Term Receivables.

Guarantees of Joint-Venture Debt

- At September 30, 2006, we had guarantees outstanding for our portion of joint-venture debt obligations, which have terms of up to 12 years. The maximum potential amount of future payments under the guarantees is approximately $160 million. Payment would be required if a joint venture defaults on its debt obligations.

Other Guarantees

- The Merey Sweeny, L.P. (MSLP) joint-venture project agreement requires the partners in the venture to pay cash calls to cover operating expenses in the event the venture does not have enough cash to cover operating expenses after setting aside the amount required for debt service over the next 18 years. Although there is no maximum limit stated in the agreement, the intent is to cover short-term cash deficiencies should they occur. Our maximum potential future payments under the agreement are currently estimated to be $100 million, assuming such a shortfall exists at some point in the future due to an extended operational disruption.

- In February 2003, we entered into two agreements establishing separate guarantee facilities of $50 million each for two LNG ships. Subject to the terms of each such facility, we will be required to make payments should the charter revenue generated by the respective ship fall below certain specified minimum thresholds, and we will receive payments to the extent that such revenues exceed those thresholds. The net maximum future payments that we may have to make over the 20-year terms of the two agreements could be up to $100 million in total. To the extent we receive any such payments, our actual gross payments over the 20 years could exceed that amount. In the event either ship is sold or a total loss occurs, we also may have recourse to the sales or insurance proceeds to recoup payments made under the guarantee facilities.

- We have other guarantees with maximum future potential payment amounts totaling $260 million, which consist primarily of dealer and jobber loan guarantees to support our marketing business, a guarantee to fund the short-term cash liquidity deficits of a lubricants joint venture, three small construction completion guarantees, a guarantee supporting a lease assignment on a corporate aircraft, a guarantee associated with a pending lawsuit and guarantees of the lease payment

---

obligations of a joint venture. The carrying amount recorded for these other guarantees, at September 30, 2006, was $50 million. These guarantees generally extend up to 15 years and payment would be required only if the dealer, jobber or lessee goes into default, if the lubricants joint venture has cash liquidity issues, if construction projects are not completed, if guaranteed parties default on lease payments, or if an adverse decision occurs in the pending lawsuit.

Indemnifications

Over the years, we have entered into various agreements to sell ownership interests in certain corporations and joint ventures and have sold several assets, including downstream and midstream assets, certain exploration and production assets, and downstream retail and wholesale sites, giving rise to qualifying indemnifications. Agreements associated with these sales include indemnifications for taxes, environmental liabilities, permits and licenses, employee claims, real estate indemnity against tenant defaults, and litigation. The terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications, at September 30, 2006, was $456 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the carrying amount recorded were $337 million of environmental accruals for known contamination that is included in asset retirement obligations and accrued environmental costs at September 30, 2006. For additional information about environmental liabilities, see Note 14—Contingencies and Commitments.

Note 16—Financial Instruments and Derivative Contracts

Derivative assets and liabilities were:

		Millions of Dollars	
		September 30 2006	December 31 2005
Derivative Assets			
Current	$	**995**	674
Long-term		**139**	193
	$	**1,134**	867
Derivative Liabilities			
Current	$	**910**	1,002
Long-term		**187**	443
	$	**1,097**	1,445

These derivative assets and liabilities appear as prepaid expenses and other current assets, other assets, other accruals, or other liabilities and deferred credits on the balance sheet.

Note 17—Comprehensive Income

Comprehensive income was:

		Millions of Dollars			
		Three Months Ended September 30		Nine Months Ended September 30	
		2006	2005	**2006**	2005
Net income	$	**3,876**	3,800	**12,353**	9,850
After-tax changes in:					
Minimum pension liability adjustment		**—**	—	—	(1)
Foreign currency translation adjustments		**(32)**	13	**906**	(579)
Unrealized loss on securities		**—**	—	**—**	(1)
Hedging activities		**(5)**	(1)	**2**	4
Comprehensive income	$	**3,839**	3,812	**13,261**	9,273

Accumulated other comprehensive income in the equity section of the balance sheet was:

		Millions of Dollars	
		September 30 2006	December 31 2005
Minimum pension liability adjustment	$	**(123)**	(123)
Foreign currency translation adjustments		**1,851**	945
Deferred net hedging loss		**(6)**	(8)
Accumulated other comprehensive income	$	**1,722**	814

Note 18—Supplemental Cash Flow Information

		Millions of Dollars	
		Nine Months Ended September 30	
		2006	2005
Non-Cash Investing and Financing Activities			
Acquisition of Burlington Resources Inc. by issuance of stock	$	**16,343**	—
Investment in properties, plants and equipment of businesses through the assumption of non-cash liabilities		**—**	261
Fair market value of properties, plants and equipment received in a nonmonetary exchange transaction		**—**	138
Cash Payments			
Interest	$	**514**	300
Income taxes		**9,313**	4,996

Note 19—Employee Benefit Plans

Pension and Postretirement Plans

Three Months Ended	Millions of Dollars					
	Pension Benefits				Other Benefits	
	September 30				September 30	
	2006		2005		**2006**	2005
	U.S.	**Int'l.**	U.S.	Int'l.		
Components of Net Periodic Benefit Cost						
Service cost	**$ 44**	**22**	37	16	**4**	5
Interest cost	**54**	**34**	43	30	**12**	12
Expected return on plan assets	**(43)**	**(31)**	(31)	(26)	**—**	—
Amortization of prior service cost	**2**	**2**	1	2	**4**	5
Recognized net actuarial loss (gain)	**22**	**10**	14	8	**(4)**	(2)
Net periodic benefit costs	**$ 79**	**37**	64	30	**16**	20

Nine Months Ended	Millions of Dollars					
	Pension Benefits				Other Benefits	
	September 30				September 30	
	2006		2005		**2006**	2005
	U.S.	**Int'l.**	U.S.	Int'l.		
Components of Net Periodic Benefit Cost						
Service cost	**$ 130**	**65**	113	53	**11**	15
Interest cost	**157**	**99**	130	94	**35**	37
Expected return on plan assets	**(126)**	**(91)**	(94)	(82)	**—**	—
Amortization of prior service cost	**7**	**6**	3	6	**14**	15
Recognized net actuarial loss (gain)	**66**	**30**	41	25	**(12)**	(4)
Net periodic benefit costs	**$ 234**	**109**	193	96	**48**	63

We recognized pension settlement losses of $2 million in the first nine months of 2005, all of which was recorded in the third quarter.

For our heritage ConocoPhillips plans, we made the following contributions during the first nine months of 2006: $398 million to our domestic qualified and non-qualified plans and $86 million to our international benefit plans. For our heritage Burlington Resources plans, we contributed $14 million to our domestic plans for the period from April through September 2006. At the end of 2005, we estimated that during 2006, we would contribute approximately $415 million to our domestic qualified and non-qualified benefit plans and $115 million to our international benefit plans. We currently expect 2006 contributions to the heritage ConocoPhillips plans to be $435 million for domestic and $125 million for international. For the heritage Burlington Resources plans, we expect to contribute $20 million during the period April through December 2006, including the $14 million noted above.

The projected benefit obligation and asset value of the pension plans acquired from Burlington Resources were $303 million and $246 million, respectively. The accumulated postretirement benefit obligation of the postretirement medical plans acquired from Burlington Resources was $36 million.

Note 20—Related Party Transactions

Significant transactions with related parties were:

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005*	**2006**	2005*
Operating revenues (a)	**$ 2,364**	2,116	**6,550**	5,594
Purchases (b)	**1,830**	1,560	**5,056**	4,498
Operating expenses and selling, general and administrative expenses (c)	**103**	99	**285**	288
Net interest income (d)	**19**	10	**49**	29

**Certain amounts reclassified to conform to current year presentation.*

(a) We sell natural gas to Duke Energy Field Services, LLC (DEFS) and crude oil to the Malaysian Refining Company Sdn. Bhd (MRC), among others, for processing and marketing. Natural gas liquids, solvents and petrochemical feedstocks are sold to Chevron Phillips Chemical Company LLC (CPChem), gas oil and hydrogen feedstocks are sold to Excel Paralubes, and refined products are sold primarily to CFJ Properties and Getty Petroleum Marketing, Inc. (a subsidiary of LUKOIL). Also, we charge several of our affiliates, including CPChem, MSLP, and Hamaca Holding LLC, for the use of common facilities, such as steam generators, waste and water treaters, and warehouse facilities.

(b) We purchase natural gas and natural gas liquids from DEFS and CPChem for use in our refinery processes and other feedstocks from various affiliates. We purchase upgraded crude oil from Petrozuata C.A. and refined products from MRC. We also pay fees to various pipeline equity companies for transporting finished refined products and a price upgrade to MSLP for heavy crude processing. We purchase base oils and fuel products from Excel Paralubes for use in our refinery and specialty businesses.

(c) We pay processing fees to various affiliates. Additionally, we pay crude oil transportation fees to pipeline equity companies.

(d) We pay and/or receive interest to/from various affiliates, including the Phillips 66 Capital II trust. See Note 9—Investments and Long-Term Receivables, for additional information on loans to affiliated companies.

Elimination amounts related to our equity percentage share of profit or loss on the above transactions were not material.

Note 21—Segment Disclosures and Related Information

We have organized our reporting structure based on the grouping of similar products and services, resulting in six operating segments:

1) E&P—This segment primarily explores for, produces and markets crude oil, natural gas and natural gas liquids on a worldwide basis. At September 30, 2006, our E&P operations were producing in the United States, Norway, the United Kingdom, the Netherlands, Canada, Nigeria, Venezuela, Ecuador, Argentina, offshore Timor Leste in the Timor Sea, Australia, China, Indonesia, Algeria,

Libya, the United Arab Emirates, Vietnam, and Russia. The E&P segment's U.S. and international operations are disclosed separately for reporting purposes.

2) Midstream—Through both consolidated and equity interests, this segment gathers and processes natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, primarily in the United States and Trinidad. The Midstream segment primarily consists of our equity investment in DEFS. Through June 30, 2005, our equity ownership in DEFS was 30.3 percent. In July 2005, we increased our ownership interest to 50 percent.

3) R&M—This segment purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia. At September 30, 2006, we owned 12 refineries in the United States, one in the United Kingdom, one in Ireland, one in Germany, and had equity interests in one refinery in Germany, two in the Czech Republic, and one in Malaysia. The R&M segment's U.S. and international operations are disclosed separately for reporting purposes.

4) LUKOIL Investment—This segment represents our investment in the ordinary shares of LUKOIL, an international, integrated oil and gas company headquartered in Russia. At September 30, 2006, our ownership interest, based on authorized and issued shares, was 19.0 percent, and our equity-method ownership interest was 19.5 percent. See Note 9—Investments and Long-Term Receivables, for additional information.

5) Chemicals—This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in CPChem.

6) Emerging Businesses—This segment includes the development of new businesses outside our traditional operations. These activities include gas-to-liquids (GTL) operations, power generation, technology solutions such as sulfur removal technologies, and emerging technologies, such as renewable fuels and emission management technologies.

Corporate and Other includes general corporate overhead, interest income and expense, discontinued operations, certain eliminations, acquisition-related costs, and various other corporate activities. Corporate assets include all cash and cash equivalents.

We evaluate performance and allocate resources based on net income. Intersegment sales are at prices that approximate market.

Analysis of Results by Operating Segment

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Sales and Other Operating Revenues				
E&P				
United States	$ **9,040**	8,388	**27,157**	22,913
International	**6,552**	5,742	**21,076**	14,980
Intersegment eliminations—U.S.	**(1,564)**	(1,069)	**(4,286)**	(2,960)
Intersegment eliminations—international	**(1,869)**	(1,204)	**(5,244)**	(3,196)
E&P	**12,159**	11,857	**38,703**	31,737
Midstream				
Total sales	**1,012**	910	**3,212**	2,781
Intersegment eliminations	**(265)**	(216)	**(796)**	(643)
Midstream	**747**	694	**2,416**	2,138
R&M				
United States	**25,240**	27,773	**73,681**	71,749
International	**10,107**	8,442	**27,819**	22,597
Intersegment eliminations—U.S.	**(211)**	(168)	**(612)**	(405)
Intersegment eliminations—international	**(5)**	(2)	**(14)**	(8)
R&M	**35,131**	36,045	**100,874**	93,933
LUKOIL Investment	**—**	—	**—**	—
Chemicals	**3**	3	**10**	10
Emerging Businesses*				
Total sales	**167**	159	**483**	445
Intersegment eliminations	**(133)**	(108)	**(361)**	(297)
Emerging Businesses	**34**	51	**122**	148

Corporate and Other	**2**	3	**6**	8
Other Adjustments*	**—**	92	**—**	210
Consolidated sales and other operating revenues	**$ 48,076**	48,745	**142,131**	128,184

**Sales and other operating revenues for the Emerging Businesses segment have been restated to reflect intersegment eliminations on sales from the Immingham power plant (Emerging Businesses segment) to the Humber refinery (R&M segment). Since these amounts were not material to the consolidated income statement, the "other adjustments" line above is required to reconcile the restated Emerging Businesses revenues to the consolidated income statement.*

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Net Income (Loss)				
E&P				
United States	**$ 995**	1,107	**3,476**	2,965
International	**909**	1,181	**4,285**	3,039
Total E&P	**1,904**	2,288	**7,761**	6,004
Midstream	**169**	88	**387**	541
R&M				
United States	**1,444**	1,096	**3,174**	2,602
International	**20**	294	**388**	598
Total R&M	**1,464**	1,390	**3,562**	3,200
LUKOIL Investment	**487**	267	**1,123**	525
Chemicals	**142**	13	**394**	209
Emerging Businesses	**11**	—	**7**	(16)
Corporate and Other	**(301)**	(246)	**(881)**	(613)
Consolidated net income	**$ 3,876**	3,800	**12,353**	9,850

	Millions of Dollars	
	September 30 2006	December 31 2005
Total Assets		
E&P		
United States	**$ 35,274**	18,434
International	**46,876**	31,662
Goodwill	**27,982**	11,423
Total E&P	**110,132**	61,519
Midstream	**2,295**	2,109
R&M		
United States	**23,874**	20,693
International	**9,237**	6,096
Goodwill	**3,948**	3,900
Total R&M	**37,059**	30,689
LUKOIL Investment	**8,635**	5,549
Chemicals	**2,420**	2,324
Emerging Businesses	**908**	858
Corporate and Other	**2,274**	3,951
Consolidated total assets	**$ 163,723**	106,999

Note 22—Income Taxes

Our effective tax rate for the third quarter and first nine months of 2006 was 51 percent and 45 percent, respectively, compared with 42 percent for the same two periods of 2005. The change in the effective tax rate for the third quarter of 2006, versus the same period of 2005, was primarily due to an unfavorable adjustment of approximately $440 million related to tax law changes in the United Kingdom enacted in

the third quarter of 2006 and a higher proportion of income in higher-tax-rate jurisdictions. The impact on the nine-month 2006 effective tax rate from the $440 million unfavorable adjustment noted above was mostly offset by a favorable $391 million adjustment in the second quarter of 2006 from enacted tax law changes in Canada. Contributing to the change in the effective tax rate for the nine-month 2006 period, versus the same period of 2005, was a higher proportion of income in higher-tax-rate jurisdictions in 2006. In addition, the first nine months of 2005 included a benefit from the utilization of capital loss carryforwards that previously had a full valuation allowance. The effective tax rate in excess of the domestic federal statutory rate of 35 percent was primarily due to foreign taxes.

Note 23—New Accounting Standards

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." This Statement defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We use fair value measurements to measure, among other items, purchased assets and investments, leases, derivative contracts and financial guarantees. We also use them to assess impairment of properties, plants and equipment, intangible assets and goodwill. The Statement does not apply to share-based payment transactions and inventory pricing. This Statement is effective January 1, 2008. We are currently evaluating the impact on our financial statements.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106 and 132(R)." This Statement requires an employer that sponsors one or more single-employer defined benefit plans to:

- Recognize the funded status of the benefit in its statement of financial position.
- Recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period, but are not recognized as components of net periodic benefit cost.
- Measure defined benefit plan assets and obligations as of the date of the employer's fiscal year end statement of financial position.
- Disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and the transition asset or obligation.

The provisions of this Statement are effective December 31, 2006, except for the requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end, which is effective December 31, 2008. We are currently evaluating the impact on our financial statements.

If SFAS No. 158 had been effective as of December 31, 2005, recorded plan assets would have been $68 million lower and recorded plan liabilities would have been $887 million higher, with corresponding offsets to other comprehensive income, deferred taxes, and intangible assets. Based on the latest information available, implementation of the new Statement at December 31, 2006, is expected to reduce recorded plan assets by about $70 million and increase recorded plan liabilities by approximately $750 million. The impact upon adoption at December 31, 2006, may differ substantially from this amount because our net plan liabilities are dependent upon future changes in interest rates, foreign currency exchange rates, the fair value of plan assets, and actuarial assumptions.

In June 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109." This Interpretation provides guidance on recognition,

classification, and disclosure concerning uncertain tax liabilities. The evaluation of a tax position will require recognition of a tax benefit if it is more likely than not that it will be sustained upon examination. This Interpretation is effective beginning January 1, 2007. We are currently evaluating the impact on our financial statements.

In June 2006, the FASB ratified the consensus reached by the EITF on Issue No. 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)." The consensus requires disclosure of either the gross or net presentation, and any such taxes reported on a gross basis should be disclosed in the interim and annual financial statements. This Issue is effective for financial reports beginning after December 15, 2006. We do not expect to change our presentation of such taxes, and we will provide additional disclosure upon the adoption of this Issue.

Supplementary Information—Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company, and ConocoPhillips Australia Funding Company, with respect to publicly held debt securities. ConocoPhillips Company is wholly owned by ConocoPhillips. ConocoPhillips Australia Funding Company is an indirect, wholly owned subsidiary of ConocoPhillips Company. ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Australia Funding Company with respect to its publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Company, and ConocoPhillips Australia Funding Company (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).
- All other non-guarantor subsidiaries of ConocoPhillips.
- The consolidating adjustments necessary to present ConocoPhillips' results on a consolidated basis.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes.

Millions of Dollars
Three Months Ended September 30, 2006

Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income						
Sales and other operating revenues	$ —	30,727	—	17,349	—	48,076
Equity in earnings of affiliates	3,972	2,460	—	1,005	(6,241)	1,196
Other income	—	253	—	60	—	313
Intercompany revenues	28	673	38	4,654	(5,393)	—
Total Revenues and Other Income	4,000	34,113	38	23,068	(11,634)	49,585
Costs and Expenses						
Purchased crude oil, natural gas and products	—	25,463	—	9,977	(4,889)	30,551
Production and operating expenses	—	1,090	—	1,573	(23)	2,640
Selling, general and administrative expenses	3	427	—	231	(11)	650
Exploration expenses	—	18	—	179	—	197
Depreciation, depletion and amortization	—	438	—	1,699	—	2,137
Impairments	—	166	—	101	—	267
Taxes other than income taxes	—	1,498	—	3,423	(68)	4,853
Accretion on discounted liabilities	—	14	—	60	—	74
Interest and debt expense	172	275	28	235	(402)	308
Foreign currency transaction gains	—	—	—	(50)	—	(50)
Minority interests	—	—	—	21	—	21
Total Costs and Expenses	175	29,389	28	17,449	(5,393)	41,648
Income from continuing operations before income taxes	3,825	4,724	10	5,619	(6,241)	7,937
Provision for income taxes	(51)	934	3	3,175	—	4,061
Income from continuing operations	3,876	3,790	7	2,444	(6,241)	3,876
Loss from discontinued operations	—	—	—	—	—	—
Net Income	$ 3,876	3,790	7	2,444	(6,241)	3,876

	Millions of Dollars				
	Three Months Ended September 30, 2005				
Income Statement	ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income					
Sales and other operating revenues	$ —	33,262	15,483	—	48,745
Equity in earnings of affiliates	3,829	2,779	823	(6,559)	872
Other income (loss)	(12)	19	35	—	42
Intercompany revenues	7	757	2,774	(3,538)	—
Total Revenues and Other Income	3,824	36,817	19,115	(10,097)	49,659
Costs and Expenses					
Purchased crude oil, natural gas and products	—	28,558	9,138	(3,188)	34,508
Production and operating expenses	—	1,079	931	(28)	1,982
Selling, general and administrative expenses	5	401	209	(3)	612
Exploration expenses	—	18	122	—	140
Depreciation, depletion and amortization	—	394	655	—	1,049
Impairments	—	—	—	—	—
Taxes other than income taxes	—	1,529	3,146	(69)	4,606
Accretion on discounted liabilities	—	9	37	—	46
Interest and debt expense	36	244	92	(250)	122
Foreign currency transaction losses	—	2	32	—	34
Minority interests	—	—	6	—	6
Total Costs and Expenses	41	32,234	14,368	(3,538)	43,105

Income from continuing operations before income taxes		3,783	4,583	4,747	(6,559)	6,554
Provision for income taxes		(21)	754	2,017	—	2,750
Income from continuing operations		3,804	3,829	2,730	(6,559)	3,804
Loss from discontinued operations		(4)	(4)	(2)	6	(4)
Net Income	$	3,800	3,825	2,728	(6,553)	3,800

	Millions of Dollars						
	Nine Months Ended September 30, 2006						
Income Statement		ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income							
Sales and other operating revenues	$	—	90,113	—	52,018	—	142,131
Equity in earnings of affiliates		12,585	8,627	—	2,841	(20,733)	3,320
Other income		—	302	—	235	—	537
Intercompany revenues		49	1,898	64	11,489	(13,500)	—
Total Revenues and Other Income		12,634	100,940	64	66,583	(34,233)	145,988
Costs and Expenses							
Purchased crude oil, natural gas and products		—	75,380	—	30,410	(12,336)	93,454
Production and operating expenses		—	3,493	—	4,129	(73)	7,549
Selling, general and administrative expenses		13	1,177	—	675	(39)	1,826
Exploration expenses		—	49	—	394	—	443
Depreciation, depletion and amortization		—	1,276	—	4,006	—	5,282
Impairments		—	204	—	113	—	317
Taxes other than income taxes		—	4,439	—	9,422	(200)	13,661
Accretion on discounted liabilities		—	43	—	164	—	207
Interest and debt expense		392	656	52	535	(852)	783
Foreign currency transaction gains		—	—	—	(10)	—	(10)
Minority interests		—	—	—	60	—	60
Total Costs and Expenses		405	86,717	52	49,898	(13,500)	123,572
Income from continuing operations before income taxes		12,229	14,223	12	16,685	(20,733)	22,416
Provision for income taxes		(124)	2,357	4	7,826	—	10,063
Income from continuing operations		12,353	11,866	8	8,859	(20,733)	12,353
Loss from discontinued operations		—	—	—	—	—	—
Net Income	$	12,353	11,866	8	8,859	(20,733)	12,353

	Millions of Dollars					
	Nine Months Ended September 30, 2005					
Income Statement		ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income						
Sales and other operating revenues	$	—	86,720	41,464	—	128,184
Equity in earnings of affiliates		9,907	7,366	2,235	(16,882)	2,626
Other income (loss)		(21)	254	148	—	381

Intercompany revenues	25	1,698	7,055	(8,778)	—
Total Revenues and Other Income	9,911	96,038	50,902	(25,660)	131,191
Costs and Expenses					
Purchased crude oil, natural gas and products	—	73,489	23,011	(7,897)	88,603
Production and operating expenses	—	3,234	2,899	(52)	6,081
Selling, general and administrative expenses	14	1,076	616	(16)	1,690
Exploration expenses	—	56	376	—	432
Depreciation, depletion and amortization	—	1,077	1,998	—	3,075
Impairments	—	—	31	—	31
Taxes other than income taxes	—	4,596	9,341	(179)	13,758
Accretion on discounted liabilities	—	27	108	—	135
Interest and debt expense	86	674	261	(634)	387
Foreign currency transaction losses	—	7	45	—	52
Minority interests	—	—	21	—	21
Total Costs and Expenses	100	84,236	38,707	(8,778)	114,265
Income from continuing operations before income taxes	9,811	11,802	12,195	(16,882)	16,926
Provision for income taxes	(47)	1,895	5,220	—	7,068
Income from continuing operations	9,858	9,907	6,975	(16,882)	9,858
Loss from discontinued operations	(8)	(8)	(2)	10	(8)
Net Income	$ 9,850	9,899	6,973	(16,872)	9,850

	Millions of Dollars					
	At September 30, 2006					
Balance Sheet	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$ —	62	—	806	(172)	696
Accounts and notes receivable	955	13,657	35	21,245	(22,847)	13,045
Inventories	—	4,076	—	2,122	—	6,198
Prepaid expenses and other current assets	6	1,107	—	3,548	—	4,661
Total Current Assets	961	18,902	35	27,721	(23,019)	24,600
Investments and long-term receivables*	83,921	57,968	2,001	25,497	(149,857)	19,530
Net properties, plants and equipment	—	18,714	—	67,413	—	86,127
Goodwill	—	15,384	—	16,546	—	31,930
Intangibles	—	949	—	144	—	1,093
Other assets	10	161	6	266	—	443
Total Assets	$ 84,892	112,078	2,042	137,587	(172,876)	163,723
Liabilities and Stockholders' Equity						
Accounts payable	$ 148	21,700	—	15,222	(23,019)	14,051
Notes payable and long-term debt due within one year	1,000	166	—	2,864	—	4,030
Accrued income and other taxes	—	309	—	5,008	99	5,416
Employee benefit obligations	—	748	—	435	1	1,184
Other accruals	117	994	35	1,527	—	2,673
Total Current Liabilities	1,265	23,917	35	25,056	(22,919)	27,354
Long-term debt	9,524	6,406	2,000	5,847	—	23,777
Asset retirement obligations and accrued environmental costs	—	1,109	—	4,474	—	5,583
Deferred income taxes	(4)	3,162	—	17,338	1	20,497
Employee benefit obligations	—	1,658	—	795	—	2,453
Other liabilities and deferred credits*	30	27,378	—	20,191	(45,237)	2,362

Total Liabilities	10,815	63,630	2,035	73,701	(68,155)	82,026
Minority interests	—	(8)	—	1,229	—	1,221
Retained earnings	32,149	20,043	7	26,668	(40,182)	38,685
Other stockholders' equity	41,928	28,413	—	35,989	(64,539)	41,791
Total	$ 84,892	112,078	2,042	137,587	(172,876)	163,723

**Includes intercompany loans.*

	Millions of Dollars				
	At December 31, 2005				
Balance Sheet	ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets					
Cash and cash equivalents	$ —	613	1,601	—	2,214
Accounts and notes receivable	775	12,573	16,484	(17,892)	11,940
Inventories	—	2,345	1,379	—	3,724
Prepaid expenses and other current assets	10	1,052	672	—	1,734
Total Current Assets	785	16,583	20,136	(17,892)	19,612
Investments and long-term receivables*	49,016	49,059	19,526	(101,875)	15,726
Net properties, plants and equipment	—	18,221	36,448	—	54,669
Goodwill	—	15,323	—	—	15,323
Intangibles	—	815	301	—	1,116
Other assets	11	228	313	1	553
Total Assets	$ 49,812	100,229	76,724	(119,766)	106,999
Liabilities and Stockholders' Equity					
Accounts payable	$ 76	17,199	12,883	(17,891)	12,267
Notes payable and long-term debt due within one year	—	323	1,435	—	1,758
Accrued income and other taxes	—	536	2,980	—	3,516
Employee benefit obligations	—	782	430	—	1,212
Other accruals	16	995	1,595	—	2,606
Total Current Liabilities	92	19,835	19,323	(17,891)	21,359
Long-term debt	1,392	6,538	2,828	—	10,758
Asset retirement obligations and accrued environmental costs	—	1,112	3,479	—	4,591
Deferred income taxes	—	3,054	8,395	(10)	11,439
Employee benefit obligations	—	1,888	575	—	2,463
Other liabilities and deferred credits*	1,966	11,384	17,012	(27,913)	2,449
Total Liabilities	3,450	43,811	51,612	(45,814)	53,059
Minority interests	—	(8)	1,217	—	1,209
Retained earnings	21,482	28,177	18,557	(40,198)	28,018
Other stockholders' equity	24,880	28,249	5,338	(33,754)	24,713
Total	$ 49,812	100,229	76,724	(119,766)	106,999

**Includes intercompany loans.*

	Millions of Dollars					
	Nine Months Ended September 30, 2006					
Statement of Cash Flows	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net cash provided by continuing operations	$ 28,139	2,881	—	5,780	(20,921)	15,879
Net cash used in discontinued operations	—	—	—	—	—	—
Net Cash Provided by Operating Activities	28,139	2,881	—	5,780	(20,921)	15,879
Cash Flows From Investing Activities						
Acquisition of Burlington Resources Inc.	—	—	—	(14,285)	—	(14,285)
Capital expenditures and investments, including dry holes	(17,494)	(2,760)	—	(9,404)	18,145	(11,513)
Proceeds from asset dispositions	—	4	—	242	—	246
Long-term advances/loans to affiliates and other investments	(14,989)	(241)	(1,992)	(3,771)	20,361	(632)
Collection of advances/loans to affiliates	—	2,513	—	1,107	(3,505)	115
Net cash used in continuing operations	(32,483)	(484)	(1,992)	(26,111)	35,001	(26,069)
Net cash used in discontinued operations	—	—	—	—	—	—
Net Cash Used in Investing Activities	(32,483)	(484)	(1,992)	(26,111)	35,001	(26,069)
Cash Flows From Financing Activities						
Issuance of debt	12,968	18,369	2,000	2,287	(20,361)	15,263
Repayment of debt	(6,400)	(1,259)	—	(171)	3,505	(4,325)
Issuance of company common stock	145	—	—	—	—	145
Repurchase of company common stock	(675)	—	—	—	—	(675)
Dividends paid on company common stock	(1,684)	(20,000)	(1)	(748)	20,749	(1,684)

Other		(10)	(58)	(7)	18,097	(18,145)	(123)
Net Cash Provided by (Used in) Financing Activities		4,344	(2,948)	1,992	19,465	(14,252)	8,601
Effect of Exchange Rate Changes on Cash and Cash Equivalents		—	—	—	71	—	71
Net Change in Cash and Cash Equivalents		—	(551)	—	(795)	(172)	(1,518)
Cash and cash equivalents at beginning of year		—	613	—	1,601	—	2,214
Cash and Cash Equivalents at End of Period	$	—	62	—	806	(172)	696

		Millions of Dollars				
		Nine Months Ended September 30, 2005				
Statement of Cash Flows		ConocoPhillips	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net cash provided by continuing operations	$	217	10,684	11,215	(9,157)	12,959
Net cash used in discontinued operations		—	(6)	—	—	(6)
Net Cash Provided by Operating Activities		217	10,678	11,215	(9,157)	12,953
Cash Flows From Investing Activities						
Capital expenditures and investments, including dry holes		—	(4,061)	(6,855)	2,343	(8,573)
Proceeds from asset dispositions		—	138	473	(3)	608
Long-term advances/loans to affiliates and other investments		—	(19,910)	(1,110)	20,832	(188)
Collection of advances/loans to affiliates		—	11,940	78	(11,859)	159
Net cash used in continuing operations		—	(11,893)	(7,414)	11,313	(7,994)
Net cash used in discontinued operations		—	—	—	—	—
Net Cash Used in Investing Activities		—	(11,893)	(7,414)	11,313	(7,994)
Cash Flows From Financing Activities						
Issuance of debt		2,901	1,391	16,873	(20,832)	333
Repayment of debt		(1,118)	(690)	(11,896)	11,859	(1,845)
Issuance of company common stock		377	—	—	—	377
Repurchase of company common stock		(1,165)	—	—	—	(1,165)
Dividends paid on company common stock		(1,210)	—	(9,160)	9,160	(1,210)
Other		(2)	(24)	2,456	(2,343)	87
Net Cash (Used in) Provided by Financing Activities		(217)	677	(1,727)	(2,156)	(3,423)
Effect of Exchange Rate Changes on Cash and Cash Equivalents		—	2	(122)	—	(120)
Net Change in Cash and Cash Equivalents		—	(536)	1,952	—	1,416
Cash and cash equivalents at beginning of year		—	879	508	—	1,387
Cash and Cash Equivalents at End of Period	$	—	343	2,460	—	2,803

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management's Discussion and Analysis contains forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations, and intentions, that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "intends," "believes," "expects," "plans," "scheduled," "anticipates," "estimates," and similar expressions identify forward-looking statements. We do not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in conjunction with the disclosures under the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995" beginning on page 65.

BUSINESS ENVIRONMENT AND EXECUTIVE OVERVIEW

On March 31, 2006, we completed the $33.9 billion acquisition of Burlington Resources Inc., an independent exploration and production company with a substantial position in North American natural gas proved reserves, production and exploratory acreage. This acquisition added approximately 2 billion barrels of oil equivalent to our proved reserves. The acquisition is reflected in our results of operations beginning in the second quarter of 2006.

Our Exploration and Production (E&P) segment had net income of $1,904 million in the third quarter of 2006, compared with $3,304 million in the second quarter of 2006 and $2,288 million in the third quarter of 2005. Net income from the E&P segment accounted for 49 percent of our total net income in the quarter. This segment continued to benefit from favorable crude oil prices. Industry crude oil prices for West Texas Intermediate were steady in the third quarter of 2006 relative to the second quarter of 2006, averaging $70.38 per barrel. Average crude prices in the third quarter of 2006 were $7.33 per barrel higher than in the third quarter of 2005. Crude oil prices continued to be influenced by strong demand from ongoing worldwide economic growth and uncertainties surrounding supply due to tensions in the Middle East and West Africa. Crude oil prices began to decline in the middle of the third quarter and into the fourth quarter of 2006, as the summer driving season ended, demand weakened, and inventory levels increased.

Industry natural gas prices for Henry Hub decreased during the third quarter of 2006 to $6.58 per million British thermal units (MMBTU), down $0.22 per MMBTU from the second quarter of 2006 and down $1.95 per MMBTU from the third quarter of 2005. Natural gas prices were impacted by high industry storage levels and the lack of hurricane-related supply disruptions to Gulf of Mexico production during the traditional peak of hurricane season.

Our Refining and Marketing segment had net income of $1,464 million in the third quarter of 2006, compared with $1,708 million in the second quarter of 2006 and $1,390 million in the third quarter of 2005. Worldwide industry refining margins weakened during the third quarter of 2006, compared with the second quarter of 2006, primarily due to weaker gasoline prices toward the end of the third quarter. Worldwide industry marketing margins improved during the third quarter of 2006, compared with the second quarter of 2006, as margins were impacted by the steep decline experienced in the gasoline and distillate spot markets.

With the rise in commodity prices over the last several years, and the subsequent increase in industry-wide spending on capital and major maintenance programs, we and other energy companies are experiencing inflation for the costs of certain goods and services in excess of general worldwide inflation trends. Such costs include rates for drilling rigs, steel and other raw materials, as well as costs for skilled labor. While we work to aggressively manage the effect these inflationary pressures have on our costs, our capital program may be impacted by these factors in the future.

RESULTS OF OPERATIONS

Unless otherwise indicated, discussion of results for the three- and nine-month periods ending September 30, 2006, is based on a comparison with the corresponding periods of 2005.

Consolidated Results

A summary of net income (loss) by business segment follows:

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Exploration and Production (E&P)	$ **1,904**	2,288	**7,761**	6,004
Midstream	**169**	88	**387**	541
Refining and Marketing (R&M)	**1,464**	1,390	**3,562**	3,200
LUKOIL Investment	**487**	267	**1,123**	525
Chemicals	**142**	13	**394**	209
Emerging Businesses	**11**	—	**7**	(16)
Corporate and Other	**(301)**	(246)	**(881)**	(613)
Net income	$ **3,876**	3,800	**12,353**	9,850

Net income was $3,876 million in the third quarter of 2006, compared with $3,800 million in the third quarter of 2005. For the nine-month periods ended September 30, 2006 and 2005, net income was $12,353 million and $9,850 million, respectively. The improved results in both 2006 periods were primarily the result of:

- The inclusion of Burlington Resources in our results of operations for the E&P segment.
- Higher crude oil and natural gas liquids prices in the E&P segment.
- Improved marketing margins in the R&M segment.
- Increased equity earnings from our investment in LUKOIL due to an increase in our ownership percentage, a benefit from alignment of LUKOIL's estimated net income to actual results, and higher estimated commodity prices.
- The recognition in 2006 of business interruption insurance claims recoveries attributable to hurricanes in 2005.

The improved results in both periods were partially offset by:

- The negative impact of changes in tax law.
- Lower refining margins in the R&M segment.
- The impairment of certain assets held for sale in the R&M and E&P segments.

· Higher interest and debt expense resulting from higher average debt levels from the Burlington Resources acquisition.

Additionally, the improved results for the first nine months of 2006 were offset slightly by a decrease in net income from our Midstream segment, reflecting the inclusion of our equity share of Duke Energy Field Services, LLC's (DEFS) gain on the sale of the general partner interest in TEPPCO Partners, LP (TEPPCO) in our 2005 results.

Income Statement Analysis

Sales and other operating revenues decreased 1 percent in the third quarter of 2006, while purchased crude oil, natural gas and products decreased 11 percent in the same period. These decreases were primarily the result of the implementation of Emerging Issues Task Force (EITF) Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." In addition, decreases in revenues and purchased products resulted from lower production levels in Alaska due to the partial shut-down of the partner-operated Prudhoe Bay field and lower volumes from the United Kingdom due to planned maintenance. These decreases were partially offset by higher petroleum products and crude oil prices, as well as higher sales volumes associated with the Burlington Resources acquisition.

Sales and other operating revenues increased 11 percent in the first nine months of 2006, and purchased crude oil, natural gas and products increased 5 percent, primarily due to higher petroleum products prices, as well as higher prices for crude oil, natural gas and natural gas liquids. In addition, sales volumes increased primarily as a result of the Burlington Resources acquisition. The increases in revenues and purchased products costs were partially offset by decreases associated with the implementation of Issue No. 04-13. See Note 2—Accounting Policies, in the Notes to Consolidated Financial Statements, for additional information on the impact of this Issue on our income statement for the third-quarter and nine-month periods.

Equity in earnings of affiliates increased 37 percent in the third quarter of 2006 and 26 percent in the nine-month period. The increases reflect improved results from:

· LUKOIL, reflecting an increase in our ownership percentage, higher estimated crude oil and petroleum products prices, and a net benefit from the alignment of LUKOIL's estimated net income to actual results.

· Our chemicals joint venture, Chevron Phillips Chemical Company LLC, due to improved olefins and polyolefins margins and volumes, as well as payments received related to business interruption insurance claims.

The increases for both periods were offset partially by lower earnings from Hamaca, our heavy-oil joint venture in Venezuela, due to a turnaround in the third quarter of 2006 and higher taxes in 2006. Improved results for the nine-month period were also partially offset by a decrease related to the inclusion of our equity share of DEFS' gain on the sale of the general partner interest in TEPPCO in our 2005 results.

Other income increased significantly in the third quarter and first nine months of 2006. The increases were primarily due to the recognition of recoveries on business interruption insurance claims in 2006 attributable to losses sustained from hurricanes in 2005.

Production and operating expenses increased 33 percent in the third quarter of 2006 and 24 percent in the nine-month period. The increases were primarily related to the acquired Burlington Resources assets and the increase of production at the Bayu-Undan field associated with the Darwin liquefied natural gas (LNG) ramp-up in Australia.

Depreciation, depletion and amortization (DD&A) increased 104 percent in the third quarter of 2006 and 72 percent in the first nine months of 2006. The increases were primarily the result of the addition of Burlington Resources assets in the E&P segment.

Impairments were $267 million in the third quarter of 2006, versus none in the same quarter of 2005. For the nine-month period of 2006, impairments increased significantly compared with the corresponding period of 2005. The increase in both periods relates to the third-quarter impairment of certain assets held for sale in the R&M and E&P segments. In addition, the nine-month period included an impairment related to a decision to withdraw an application for license under the federal Deepwater Port Act associated with a proposed LNG regasification terminal located offshore Alabama. In 2006, we also impaired properties located offshore Australia due to increased accrued dismantlement and removal costs. See Note 12—Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Interest and debt expense increased 152 percent in the third quarter of 2006 and 102 percent in the first nine months of 2006. The increases in both periods were primarily due to higher average debt levels in 2006 as a result of the acquisition of Burlington Resources.

Segment Results

E&P

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Net Income				
Alaska	$ **425**	730	**1,877**	1,834
Lower 48	**570**	377	**1,599**	1,131
United States	**995**	1,107	**3,476**	2,965
International	**909**	1,181	**4,285**	3,039

	$ **1,904**	2,288	**7,761**	6,004

	Dollars Per Unit			
Average Sales Prices				
Crude oil (per barrel)				
United States	$ **67.25**	57.31	**63.05**	49.59
International	**67.45**	59.52	**65.27**	51.46
Total consolidated	**67.37**	58.49	**64.30**	50.61
Equity affiliates*	**46.98**	45.25	**47.36**	37.45
Worldwide	**65.04**	56.64	**62.18**	48.80
Natural gas—lease (per thousand cubic feet)				
United States	**5.98**	7.48	**6.21**	6.40
International	**5.87**	5.60	**6.23**	5.25
Total consolidated	**5.92**	6.40	**6.22**	5.71
Equity affiliates*	**.32**	.20	**.30**	.25
Worldwide	**5.91**	6.38	**6.21**	5.70

	Millions of Dollars			
Worldwide Exploration Expenses				
General administrative; geological and geophysical; and lease rentals	$ **142**	85	**302**	221
Leasehold impairment	**37**	23	**89**	61
Dry holes	**18**	32	**52**	150
	$ **197**	140	**443**	432

**Excludes our equity share of LUKOIL reported in the LUKOIL Investment segment.*

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
	Thousands of Barrels Daily			
Operating Statistics				
Crude oil produced				
Alaska	**234**	281	**265**	296
Lower 48	**119**	56	**101**	60
United States	**353**	337	**366**	356
European North Sea	**240**	254	**246**	259
Asia Pacific	**111**	100	**109**	98
Canada	**26**	22	**25**	23
Middle East and Africa	**126**	53	**103**	54
Other areas	**9**	—	**6**	—
Total consolidated	**865**	766	**855**	790
Equity affiliates*	**104**	124	**117**	122
	969	890	**972**	912
Natural gas liquids produced				
Alaska	**11**	18	**18**	19
Lower 48	**75**	30	**58**	30
United States	**86**	48	**76**	49
European North Sea	**11**	13	**12**	12
Asia Pacific	**20**	20	**20**	15
Canada	**28**	10	**23**	10
Middle East and Africa	**1**	1	**1**	2
	146	92	**132**	88
	Millions of Cubic Feet Daily			
Natural gas produced**				
Alaska	**123**	173	**150**	169
Lower 48	**2,320**	1,218	**1,953**	1,194
United States	**2,443**	1,391	**2,103**	1,363
European North Sea	**955**	847	**1,061**	992
Asia Pacific	**670**	358	**579**	340
Canada	**1,154**	429	**930**	422
Middle East and Africa	**134**	74	**129**	77
Other areas	**23**	—	**16**	—
Total consolidated	**5,379**	3,099	**4,818**	3,194
Equity affiliates*	**8**	10	**9**	8
	5,387	3,109	**4,827**	3,202
	Thousands of Barrels Daily			
Mining operations				
Syncrude produced	**23**	21	**20**	19

**Excludes our equity share of LUKOIL, which is reported in the LUKOIL Investment segment.*
***Represents quantities available for sale. Excludes gas equivalent of natural gas liquids shown above.*

The E&P segment explores for, produces and markets crude oil, natural gas, and natural gas liquids on a worldwide basis. It also mines deposits of oil sands in Canada to extract the bitumen and upgrade it into a synthetic crude oil. At September 30, 2006, our E&P operations were producing in the United States, Norway, the United Kingdom, the Netherlands, Canada, Nigeria, Venezuela, Ecuador, Argentina, offshore Timor Leste in the Timor Sea, Australia, China, Indonesia, Algeria, Libya, the United Arab Emirates, Vietnam, and Russia.

Net income for the E&P segment decreased 17 percent in the third quarter of 2006, primarily due to the negative impacts of changes in tax laws and lower natural gas prices. These decreases were partially offset by higher production, primarily due to the addition of Burlington Resources assets, as well as higher crude oil prices. Net income for the first nine months of 2006 increased 29 percent. The increase was mainly the result of higher crude oil, natural gas and natural gas liquids production and prices, partially offset by the negative impact of changes in tax laws. See the Business Environment and Executive Overview section for additional information on industry crude oil and natural gas prices.

<u>*U.S. E&P*</u>
Net income for our U.S. E&P operations decreased 10 percent in the third quarter of 2006, primarily resulting from lower natural gas prices and higher production taxes in Alaska. In addition, production levels in Alaska were lower due to the partial shut-down of the Prudhoe Bay field, discussed in more detail below. These items were partially offset by higher crude oil, natural gas and natural gas liquids production in the Lower 48, as well as higher crude oil prices.

Net income for the first nine months of 2006 increased 17 percent, primarily as a result of higher crude oil prices, as well as increased crude oil, natural gas and natural gas liquids production in the Lower 48. These increases were partially offset by higher production taxes in Alaska, lower crude oil production in Alaska and lower natural gas prices.

In August 2006, the state of Alaska enacted new production tax legislation, retroactive to April 1, 2006, but the resulting tax will not be paid until March 2007. The new legislation results in a higher production tax structure for ConocoPhillips. This retroactive tax structure resulted in an estimated after-tax negative impact of $187 million for the third quarter of 2006.

U.S. E&P production on a barrel-of-oil-equivalent (BOE) basis averaged 846,000 BOE per day in the third quarter of 2006, an increase of 37 percent from 617,000 BOE per day in the third quarter of 2005. Production was favorably impacted in 2006 by the addition of volumes from the Burlington Resources assets, offset slightly by decreases in production at the partner-operated Prudhoe Bay field in Alaska. The Prudhoe Bay field was partially shut down during the third quarter of 2006 as a result of the discovery of a small leak in an oil sales line and concerns with pipeline corrosion. As of the end of October, most production had been restored.

<u>*International E&P*</u>
Net income from our international E&P operations decreased 23 percent in the third quarter of 2006. The decrease was primarily the result of an increase in the rate of supplementary corporation tax enacted in the United Kingdom. In addition, net income decreased due to a higher extraction tax in Venezuela. These decreases were offset partially by higher crude oil and natural gas production, higher crude oil prices, and higher LNG production from the Darwin LNG facility in Australia.

Net income for the first nine months of 2006 increased 41 percent, reflecting higher crude oil and natural gas prices and production, as well as higher levels of LNG production from the Darwin LNG facility associated with the Bayu-Undan field. These increases were partially offset by the negative impacts of tax law changes.

The following international tax legislation was enacted during the first nine months of 2006:

- In the United Kingdom, the rate of supplementary corporation tax applicable to U.K. upstream activity increased in July from 10 percent to 20 percent, retroactive to January 1, 2006. This resulted in the U.K. upstream corporation tax increasing from 40 percent to 50 percent. This resulted in additional tax expense during the third quarter of 2006 of approximately $440 million, comprised of approximately $270 million for revaluing the beginning balances of the deferred tax liability, and approximately $170 million to reflect the new rate from January 1, 2006.

- In Canada, the Alberta government reduced the Alberta corporate income tax rate from 11.5 percent to 10 percent, effective April 2006. In addition, the Canadian federal government announced federal tax rate reductions whereby the federal tax rate will decline by 2 percent over the period 2008 to 2010 and the 1.12 percent federal surtax will be eliminated in 2008. As a result of these tax rate reductions, we recorded a one-time favorable adjustment in the E&P segment of $401 million to our deferred tax liability in the second quarter of 2006.

- The China Ministry of Finance enacted a “Special Levy on Earnings from Petroleum Enterprises,” effective March 26, 2006. The special levy, which is based on the cost recovery price of crude oil, starts at a rate of 20 percent of the excess price when crude oil prices exceed $40 per barrel, and increases 5 percent for every corresponding $5 per barrel increase in the cost recovery price. Once the cost recovery price reaches $60 per barrel, a maximum levy rate of 40 percent is applied. This special levy resulted in a negative impact to earnings of $35 million in the first nine months of 2006.

- The Venezuelan government enacted an extraction tax of 33.33 percent with an effective date of May 2006. The tax is calculated based on the value of oil extracted and is offset by royalty payments. This extraction tax resulted in a reduction in our equity earnings from affiliates of $65 million in the first nine months of 2006.

International E&P production averaged 1,167,000 BOE per day in the third quarter of 2006, an increase of 32 percent from 883,000 BOE per day in the third quarter of 2005. Production was favorably impacted in 2006 by the addition of Burlington Resources assets, as well as higher gas production at Bayu-Undan associated with the Darwin LNG ramp-up in Australia.

Our Syncrude mining operations produced 23,000 barrels per day in the third quarter of 2006, compared with 21,000 barrels per day in the third quarter of 2005.

Midstream

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
	Millions of Dollars			
Net Income*	$ **169**	88	**387**	541
**Includes DEFS-related net income:*	*$* ***128***	*76*	***312***	*486*

	Dollars Per Barrel			
Average Sales Prices				
U.S. natural gas liquids*				
Consolidated	$ $ **44.10**	39.60	**41.16**	34.68
Equity affiliates	**43.00**	38.31	**40.49**	33.42

**Prices are based on index prices from the Mont Belvieu and Conway market hubs that are weighted by natural gas liquids component and location mix.*

	Thousands of Barrels Daily			
Operating Statistics				
Natural gas liquids extracted*	**210**	205	**209**	193
Natural gas liquids fractionated**	**138**	138	**143**	179

**Includes our share of equity affiliates, except LUKOIL, which is reported in the LUKOIL Investment segment.*
***Excludes DEFS.*

The Midstream segment purchases raw natural gas from producers and gathers natural gas through an extensive network of pipeline gathering systems. The natural gas is then processed to extract natural gas liquids from the raw gas stream. The remaining residue gas is marketed to electrical utilities, industrial users, and gas marketing companies. Most of the natural gas liquids are fractionated—separated into individual components like ethane, butane and propane—and marketed as chemical feedstock, fuel, or blendstock. The Midstream segment consists of our 50 percent equity investment in Duke Energy Field Services, LLC (DEFS), as well as our other natural gas gathering and processing operations, and natural gas liquids fractionation and marketing businesses, primarily in the United States and Trinidad.

Net income from the Midstream segment increased 92 percent in the third quarter of 2006, primarily due to a $30 million positive tax adjustment recorded in the third quarter of 2006 to the gain recorded in 2005 on the sale of DEFS' interest in TEPPCO Partners, L.P. (TEPPCO), as well as higher natural gas liquids prices.

Net income for the first nine months of 2006 decreased 28 percent, primarily due to the gain from the sale of DEFS' interest in TEPPCO included in our equity earnings from DEFS during the first quarter of 2005. Our net share of this gain, recorded in 2005, was $306 million on an after-tax basis. This decrease was partially offset by the impact of higher natural gas liquids prices and an increased ownership interest in DEFS. In July 2005, our ownership interest in DEFS increased from 30.3 percent to 50 percent.

R&M

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
	Millions of Dollars			
Net Income				
United States	$ $ **1,444**	1,096	**3,174**	2,602
International	**20**	294	**388**	598
	$ $ **1,464**	1,390	**3,562**	3,200

	Dollars Per Gallon			
U.S. Average Sales Prices*				
Automotive gasoline				
Wholesale**	$ $ **2.27**	2.00	**2.13**	1.71
Retail	**2.46**	2.14	**2.28**	1.86
Distillates—wholesale**	**2.31**	1.97	**2.15**	1.71

**Excludes excise taxes.*

***Branded marketing sales only.*

	Thousands of Barrels Daily			
Operating Statistics				
Refining operations*				
United States				
Crude oil capacity	**2,208**	2,182	**2,208**	2,179
Crude oil runs	**2,127**	2,040	**1,990**	2,044
Capacity utilization (percent)	**96%**	93	**90**	94
Refinery production	**2,334**	2,223	**2,173**	2,238
International				
Crude oil capacity**	**693**	428	**637**	428
Crude oil runs	**617**	431	**586**	420
Capacity utilization (percent)	**89%**	101	**92**	98
Refinery production	**643**	448	**613**	434
Worldwide				
Crude oil capacity**	**2,901**	2,610	**2,845**	2,607
Crude oil runs	**2,744**	2,471	**2,576**	2,464
Capacity utilization (percent)	**95%**	95	**91**	95
Refinery production	**2,977**	2,671	**2,786**	2,672

**Includes our share of equity affiliates, except for our share of LUKOIL, which is reported in the LUKOIL Investment segment.*
***Weighted-average crude oil capacity for the nine-month period. Actual capacity at September 30, 2006, was 693,000 barrels per day for our international refineries, and 2,901,000 barrels per day worldwide.*

Petroleum products sales volumes				
United States				
Automotive gasoline	**1,369**	1,397	**1,309**	1,376
Distillates	**668**	725	**638**	683
Aviation fuels	**180**	203	**189**	205
Other products	**519**	526	**530**	518
	2,736	2,851	**2,666**	2,782
International	**749**	470	**772**	481
	3,485	3,321	**3,438**	3,263

The R&M segment's operations encompass refining crude oil and other feedstocks into petroleum products (such as gasoline, distillates and aviation fuels), buying and selling crude oil and petroleum products, and transporting, distributing and marketing petroleum products. R&M has operations in the United States, Europe and Asia Pacific.

Net income from the R&M segment increased 5 percent in the third quarter of 2006 and 11 percent in the nine-month period. The increase during the third quarter was primarily due to higher worldwide marketing margins and worldwide refining volumes. In addition, net income increased due to the recognition of a net benefit related to business interruption insurance. These items were partially offset by lower worldwide refining margins, the impairment of certain assets held for sale, and higher depreciation expense and maintenance costs. See the Business Environment and Executive Overview section for our view of the factors supporting industry refining and marketing margins.

The increase during the nine-month period resulted primarily from higher domestic refining and worldwide marketing margins and the business interruption insurance benefit. The increase in net income was partially offset by the impairment on assets held for sale, lower domestic refining volumes and international refining margins, higher turnaround, maintenance and utility costs, and higher depreciation expense. The nine-month results for 2005 also included a gain on asset sales.

U.S. R&M
Net income from our U.S. R&M operations increased 32 percent in the third quarter of 2006 and 22 percent in the nine-month period. The increase during the third quarter was primarily the result of higher marketing margins and refining volumes and the recognition of the business interruption insurance benefit. These items were offset partially by lower refining margins and the recognition of an impairment on certain assets held for sale, as well as higher maintenance and depreciation expenses. The increase in the nine-month period resulted primarily from improved refining and marketing margins and the business interruption insurance benefit. These increases were partially offset by lower refining and marketing volumes and higher turnaround, maintenance and utility costs, as well as higher depreciation expense.

Our U.S. refining capacity utilization rate was 96 percent in the third quarter of 2006, compared with 93 percent in the corresponding period of 2005. The improvement was primarily due to the return to normal operations of the Trainer refinery in Pennsylvania after an extended full-plant turnaround. In addition, our refinery capacity utilization rate in 2005 was impacted by downtime related to hurricanes. The improved rate was offset partially by downtime at the Wood River refinery in Illinois due to damage sustained during a severe storm. The Wood River refinery returned to normal operations during the quarter.

International R&M
Net income from our international R&M operations decreased 93 percent in the third quarter of 2006 and 35 percent in the nine-month period. Both decreases were primarily the result of lower refining margins and the recognition of an impairment charge on certain assets held for sale. Depreciation expense was higher in the third quarter of 2006 due to the addition of the Wilhelmshaven refinery in Germany. In addition, maintenance and utility costs and depreciation expense were higher in the nine-month period of 2006, partially offset by lower turnaround costs. The decreases in both periods were partially offset by higher marketing margins and sales volumes, and higher refining volumes.

Our international refining capacity utilization rate was 89 percent in the third quarter of 2006, compared with 101 percent in the corresponding quarter of 2005. The decrease was primarily due to planned downtime at certain refineries.

LUKOIL Investment

		Millions of Dollars		
	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Net Income	$ **487**	267	**1,123**	525
Operating Statistics*				
Net crude oil production (thousands of barrels daily)	**388**	253	**347**	220
Net natural gas production (millions of cubic feet daily)	**288**	79	**244**	65
Net refinery crude oil processed (thousands of barrels daily)	**164**	138	**165**	110

**Represents our net share of our estimate of LUKOIL's production and processing.*

This segment represents our investment in the ordinary shares of LUKOIL, an international, integrated oil and gas company headquartered in Russia, which we account for under the equity method. Our ownership interest in LUKOIL was 19.0 percent at September 30, 2006, based on 850.6 million shares authorized and issued.

During the third quarter of 2006, we concluded certain treasury shares held by LUKOIL subsidiaries should not be considered outstanding for determining our equity-method ownership interest in LUKOIL in accordance with accounting principles generally accepted in the United States. Accordingly, we recorded a cumulative adjustment increasing equity earnings by $42 million, reflecting the increase in our equity-method ownership interest from the date of our initial investment in LUKOIL through June 30, 2006. Excluding these treasury shares (20.2 million of the 22.8 million treasury shares, based on latest available public data) from the denominator of our ownership calculation, our equity-method ownership interest was 19.5 percent at September 30, 2006.

In addition to our estimate of our equity share of LUKOIL's earnings, this segment also reflects the amortization of the basis difference between our equity interest in the net assets of LUKOIL and the historical cost of our investment in LUKOIL and includes the costs associated with the employees seconded to LUKOIL.

Because LUKOIL's accounting cycle close and preparation of U.S. generally accepted accounting principles (GAAP) financial statements are not available prior to our reporting deadline, our equity earnings and statistics for our LUKOIL investment are estimated, based on current market indicators, historical production and cost trends of LUKOIL, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. This estimate-to-actual adjustment will be a recurring component of future period results. The adjustment to our LUKOIL Investment second-quarter 2006 estimated results, recorded in the third quarter of 2006, increased net income $74 million.

Net income from the LUKOIL Investment segment increased 82 percent in the third quarter of 2006 and 114 percent in the first nine months of 2006. These increases were the result of the ownership interest adjustment, the estimate-to-actual adjustment, and higher estimated commodity prices.

Chemicals

		Millions of Dollars		
	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Net Income	$ **142**	13	**394**	209

The Chemicals segment consists of our 50 percent interest in Chevron Phillips Chemical Company LLC (CPChem), which we account for using the equity method of accounting. CPChem uses natural gas liquids and other feedstocks to produce petrochemicals, such as ethylene, propylene, styrene, benzene, and paraxylene. These products are then marketed and sold, or used as feedstocks to produce plastics and commodity chemicals, such as polyethylene, polystyrene and cyclohexane.

Net income from the Chemicals segment was $142 million in the third quarter of 2006 and $13 million in the corresponding period of 2005. Net income increased 89 percent in the nine-month period. Results for both periods of 2006 reflected improved olefins and polyolefins margins, and a hurricane-related business interruption insurance net benefit. The results for the third quarter of 2006 included lower utility costs due to decreased natural gas prices, and results for the nine-month period reflected higher sales volumes.

Emerging Businesses

		Millions of Dollars		
	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Net Income (Loss)				
Technology solutions	$ **(3)**	(5)	**(19)**	(11)
Gas-to-liquids	**(4)**	(4)	**(11)**	(18)

Power	26	17	60	28
Other	(8)	(8)	(23)	(15)
	$ 11	—	7	(16)

The Emerging Businesses segment includes the development of new businesses outside our traditional operations. These activities include power generation, gas-to-liquids (GTL), technology solutions such as sulfur removal technologies, and emerging technologies, such as renewable fuels and emission management technologies.

The Emerging Businesses segment had net income of $11 million in the third quarter of 2006, and segment results were at break even in the corresponding period of 2005. The improved results were primarily due to increased power generation at the Immingham power plant in the United Kingdom. The first nine months of 2006 resulted in net income of $7 million, compared with a net loss of $16 million in the corresponding period of 2005. The improved results in the first nine months of 2006 reflect improved domestic and international power margins. These increases were offset partially by the write-down of a damaged gas turbine at a domestic power plant, as well as lower domestic and international power volumes.

Corporate and Other

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005*	**2006**	2005*
Net Income (Loss)				
Net interest	$ **(242)**	(139)	**(602)**	(335)
Corporate general and administrative expenses	**(35)**	(64)	**(100)**	(168)
Discontinued operations	**—**	(4)	**—**	(8)
Acquisition-related costs	**(32)**	—	**(76)**	—
Other	**8**	(39)	**(103)**	(102)
	$ **(301)**	(246)	**(881)**	(613)

**Certain amounts reclassified to conform to current year presentation.*

After-tax net interest consists of interest and financing expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt. Net interest increased 74 percent in the third quarter of 2006 and 80 percent in the nine-month period. The increases were primarily due to higher average debt levels as a result of the acquisition of Burlington Resources. The increases were partially offset by increased interest income and higher amounts of interest being capitalized, as well as the inclusion of premiums on the early retirement of debt in 2005.

After-tax corporate general and administrative expenses decreased 45 percent in the third quarter of 2006 and 40 percent in the nine-month period, primarily due to reduced benefit-related expenses.

Acquisition-related costs included change-in-control costs associated with seismic contracts and other transition costs.

The category "Other" includes foreign currency transaction gains and losses, and environmental costs associated with sites no longer in operation. Results from Other improved during the third quarter of 2006 primarily due to favorable foreign currency transactions. Results from Other were slightly lower during the first nine months of 2006 as a result of favorable foreign currency transactions offset by the negative impact of tax law changes.

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars	
	At September 30 2006	At December 31 2005
Current ratio	**.9**	.9
Notes payable and long-term debt due within one year	$ **4,030**	1,758
Total debt	$ **27,807**	12,516
Minority interests	$ **1,221**	1,209
Common stockholders' equity	$ **80,476**	52,731
Percent of total debt to capital*	**25%**	19
Percent of floating-rate debt to total debt	**42%**	9

**Capital includes total debt, minority interests and common stockholders' equity.*

To meet our short- and long-term liquidity requirements, we look to a variety of funding sources, primarily cash generated from operating activities. During the first nine months of 2006, available cash was used to support our ongoing capital expenditures and investments program, pay dividends, repurchase shares of our common stock, and fund a portion of our acquisition of Burlington Resources. Total dividends paid on our common stock during the first nine months were $1,684 million. During the first nine months of 2006, cash and cash equivalents declined $1,518 million to $696 million, inclusive of cash acquired with the Burlington Resources acquisition.

In addition to cash flows from operating activities, we also rely on our cash balance, commercial paper and credit facility programs, and our shelf registration statements to support our short- and long-term liquidity requirements. We anticipate these sources of liquidity will be adequate to meet our funding requirements through 2006, including our capital spending program and required debt payments.

On March 31, 2006, we closed on our $33.9 billion acquisition of Burlington Resources by issuing approximately 270.4 million shares of our common stock, including 32.1 million treasury shares, and paying approximately $17.5 billion in cash, of which about $15.3 billion was financed with short- and long-term debt. See Significant Sources of Capital below, as well as Note 4—Acquisition of Burlington Resources Inc., and Note 13—Debt, in the Notes to Consolidated Financial Statements, for additional information on the acquisition.

Significant Sources of Capital

Operating Activities
During the first nine months of 2006, cash from operating activities totaled $15,879 million, compared with cash from operations of $12,953 million in the corresponding period of 2005. The 23 percent increase resulted primarily from higher income from continuing operations.

Income from continuing operations increased $2,495 million, compared with the same period of 2005. Contributing to the improvement was the inclusion of the operating activity of Burlington Resources beginning in the second quarter of 2006 and higher crude oil sales prices. See the "Results of Operations" section for additional discussion.

While the stability of our cash flows from operating activities benefits from geographic diversity and the effects of upstream and downstream integration, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, natural gas and natural gas liquids, as well as refining and marketing margins. During the first nine months of 2006 and 2005, we benefited from favorable crude oil and natural gas prices, as well as refining margins. The sustainability of these prices and margins are driven by market conditions over which we have no control. For example, crude oil prices have declined since mid-August from the low-$70's per barrel to the upper-$50's per barrel as of late October. As a result, we would expect a corresponding decline in our cash from operations, absent other mitigating factors.

In addition, the level of our production volumes of crude oil, natural gas and natural gas liquids also impacts our cash flows. These production levels are impacted by such factors as acquisitions and dispositions of fields, field production decline rates, new technologies, operating efficiency, weather conditions, the addition of proved reserves through exploratory success, and the timely and cost-effective development of those proved reserves. While we actively manage these factors that affect production, they do cause certain variability in production levels, although historically this variability has not been as significant as that experienced with sales prices.

Asset Sales
During the first nine months of 2006, we had proceeds from assets sales of $246 million. Included in this amount was our interest in the Permian Basin Royalty Trust.

Commercial Paper and Credit Facilities
At September 30, 2006, we had two revolving credit facilities totaling $5 billion. Expiration dates for both facilities were extended one year during the third quarter of 2006 to October 2011. We also have a $2.5 billion five-year revolving credit facility we entered into in April 2006. These facilities may be used as direct bank borrowings, as support for the ConocoPhillips $7.5 billion commercial paper program, as support for the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, or as support for issuances of letters of credit totaling up to $750 million. The facilities are broadly syndicated among financial institutions and do not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The credit facilities do contain a cross-default provision relating to our, or any of our consolidated subsidiaries', failure to pay principal or interest on other debt obligations of $200 million or more. At September 30, 2006, and December 31, 2005, we had no outstanding borrowings under the credit facilities, but $41 million and $62 million, respectively, in letters of credit had been issued. Under both commercial paper programs, there was $3,470 million of commercial paper outstanding at September 30, 2006, compared with $32 million at December 31, 2005. The commercial paper increase resulted from efforts to reduce the bridge facilities discussed below.

At September 30, 2006, our primary funding source for short-term working capital needs was the ConocoPhillips $7.5 billion commercial paper program, a portion of which may be denominated in other currencies (limited to euro 3 billion equivalent). Commercial paper maturities are generally limited to 90 days.

Financing the Burlington Resources Inc. Acquisition
We completed our acquisition of Burlington Resources Inc. by issuing approximately 270.4 million of our common shares, 32.1 million of which were issued from treasury shares, and paying approximately $17.5 billion in cash. We acquired $3.2 billion in cash and assumed $4.3 billion of debt from Burlington Resources in the acquisition. The cash payment was made through borrowings from two $7.5 billion bridge facilities, combined with $2.1 billion from cash balances and the issuance of $300 million in commercial paper. The bridge facilities were both 364-day loan facilities with pricing and terms similar to our existing revolving credit facilities.

In April 2006, we entered into and funded a $5 billion five-year term loan, closed on the previously mentioned $2.5 billion five-year revolving credit facility, increased the ConocoPhillips commercial paper program to $7.5 billion, and issued $3 billion of debt securities. The term loan and new credit facility were executed with a group of 36 banks with terms and pricing provisions similar to our two other existing revolving credit facilities. The proceeds from the term loan, debt securities and issuances of commercial paper, together with our cash balances and cash provided by operations, allowed us to repay the $15 billion bridge facilities during the second and third quarters of 2006.

The $3 billion of debt securities were issued under a new shelf registration statement filed with the U.S. Securities and Exchange Commission (SEC) in early April 2006 allowing for the issuance of various types of debt and equity securities. Of this issuance, $1 billion of Floating Rate Notes due April 11, 2007, were issued by ConocoPhillips, and $1.25 billion of Floating Rate Notes due April 9, 2009, and $750 million of 5.50% Notes due 2013 were issued by ConocoPhillips Australia Funding Company, a wholly owned subsidiary. ConocoPhillips guarantees the obligations of ConocoPhillips Australia Funding Company. In October 2006, we filed a post-effective amendment to this registration statement to terminate the offering of securities under the registration statement.

Shelf Registrations
In mid-April 2006, we filed a universal shelf registration statement with the SEC, under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities.

In October 2006, we filed a shelf registration statement with the SEC under which ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II, both wholly owned subsidiaries, could issue an indeterminate amount of senior debt securities, fully and unconditionally guaranteed by ConocoPhillips. See the “Capital Requirements” section below for additional information on the issuance of debt securities under this registration statement.

Minority Interests
At September 30, 2006, we had outstanding $1,221 million of equity in less than wholly owned consolidated subsidiaries held by minority interest owners, including a minority interest of $508 million in Ashford Energy Capital S.A. The remaining minority interest amounts are primarily related to controlled-operating joint ventures with minority interest owners. The largest of these, $688 million, was related to the Bayu-Undan liquefied natural gas project in the Timor Sea and northern Australia.

Off-Balance Sheet Arrangements

Affiliated Companies
Qatargas 3 is an integrated project to produce and liquefy natural gas from Qatar’s North field. We own a 30 percent interest in the project. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent). Our interest is held through a jointly owned company, Qatar Liquefied Gas Company Limited (3), for which we use the equity method of accounting. Qatargas 3 secured project financing of $4 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. Prior to project completion certification, all loans, including the ConocoPhillips loan facilities, are guaranteed by the participants, based on their respective ownership interests. Accordingly, our maximum exposure to this financing structure is $1.2 billion. Upon completion certification, which is expected by December 31, 2009, all project loan facilities, including the ConocoPhillips loan facilities, will become non-recourse to the project participants.

At September 30, 2006, Qatargas 3 had $1.1 billion outstanding under all the loan facilities, including $336 million loaned by ConocoPhillips.

Capital Requirements

For information about the financing of the Burlington Resources Inc. acquisition or our capital expenditures and investments, see the “Significant Sources of Capital” section and the “Capital Spending” section, respectively.

Our debt balance at September 30, 2006, was $27.8 billion and our debt-to-capital ratio was 25 percent, compared with a debt balance of $12.5 billion and a debt-to-capital ratio of 19 percent at year-end 2005. Both increases reflect debt issuances of $15.3 billion during the first quarter of 2006 related to the acquisition of Burlington Resources. In addition, we assumed $4.3 billion of Burlington Resources debt, including the recognition of an increase of $406 million to record the debt at its fair value. See Note 13—Debt, in the Notes to Consolidated Financial Statements, for additional information about these debt increases.

In October 2006, we redeemed our $1.25 billion 5.45% Notes upon their maturity and redeemed our $500 million 5.60% Notes due December 2006, and our $350 million 5.70% Notes due March 2007, at a premium of $1 million, plus accrued interest. In order to finance the maturity and call of the above notes, ConocoPhillips Canada Funding Company I, a wholly owned subsidiary, issued $1.25 billion of 5.625% Notes due 2016, and ConocoPhillips Canada Funding Company II, a wholly owned subsidiary, issued $500 million of 5.95% Notes due 2036, and $350 million of 5.30% Notes due 2012. ConocoPhillips and ConocoPhillips Company guarantee the obligations of ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II.

In May 2006, we redeemed our $240 million 7.625% Notes upon their maturity and redeemed our $129 million 6.60% Notes due in 2007, at a premium of $4 million, plus accrued interest.

On February 4, August 11, and November 15, 2005, we announced separate stock repurchase programs, each of which provides for the purchase of up to $1 billion of the company’s common stock over a period of up to two years. Acquisitions for the share repurchase programs are made at management’s discretion at prevailing prices, subject to market conditions and other factors. Purchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock purchased under the programs are initially held as treasury shares. During the first nine months of 2006, we purchased 10.6 million shares of our common stock, at a cost of $675 million under the programs. Through October 31, 2006, under the three programs, we had purchased a total of 43.8 million shares, at a cost of $2.7 billion.

In December 2005, we entered into a credit agreement with Qatargas 3, whereby we will provide loan financing of approximately $1.2 billion for the construction of an LNG train in Qatar. This financing will represent 30 percent of the project’s total debt financing. Through September 30, 2006, we had provided $336 million in loan financing, including accrued interest. See the “Off-Balance Sheet Arrangements” section for additional information on Qatargas 3.

In July 2004, we announced the finalization of our transaction with Freeport LNG Development, L.P. (Freeport LNG) to participate in an LNG receiving terminal in Quintana, Texas. Construction began in early 2005. We do not have an ownership interest in the facility, but we do have a 50 percent interest in the general partnership managing the venture, along with contractual rights to regasification capacity of the terminal. We entered into a credit agreement with Freeport LNG, whereby we will provide loan financing of approximately $630 million for the construction of the facility. Through September 30, 2006, we had provided $457 million in loan financing, including accrued interest.

In the fall of 2004, ConocoPhillips and LUKOIL agreed to the expansion of the Varandey terminal as part of our investment in the OOO Naryanmarneftegaz (NMNG) joint venture. Production from the NMNG joint-venture fields is transported via pipeline to LUKOIL's existing terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets. LUKOIL intends to complete an expansion of the terminal oil-throughput capacity from 30,000 barrels per day to up to 240,000 barrels per day, with ConocoPhillips participating in the design and financing of the terminal expansion. We have an obligation to provide loan financing to Varandey Terminal Company for 30 percent of the costs of the terminal expansion, but we will have no governance or ownership interest in the terminal. Based on the current estimate from the operator, we assess our total loan obligation for the terminal expansion to be approximately $350 million at current exchange rates. This amount will be adjusted as the project's cost estimate and schedule are updated and the ruble exchange rate fluctuates. Through September 30, 2006, we had provided $167 million in loan financing, including accrued interest.

Our loans to Qatargas 3, Freeport LNG and Varandey Terminal Company are included in the "Investments and long-term receivables" line on the balance sheet.

Contractual Obligations

Our contractual purchase obligations at September 30, 2006, were estimated to be $85 billion, a decrease of $1 billion from the amount reported at December 31, 2005, of $86 billion. The decrease results from lower crude oil and natural gas volumes, offset by higher capital expenditure commitments and higher purchase obligations as a result of the Burlington Resources acquisition.

Capital Spending

Capital Expenditures and Investments

	Millions of Dollars Nine Months Ended September 30 **2006**	2005
E&P		
United States—Alaska	$ **615**	517
United States—Lower 48	**1,388**	704
International	**4,829**	3,797
	6,832	5,018
Midstream	**2**	839
R&M		
United States	**1,128**	968
International	**1,356**	107
	2,484	1,075
LUKOIL Investment	**1,962**	1,523
Chemicals	**—**	—
Emerging Businesses	**46**	5
Corporate and Other	**187**	113
	$ **11,513**	8,573
United States	$ **3,358**	3,140
International	**8,155**	5,433
	$ **11,513**	8,573

E&P

UNITED STATES

Alaska

During the first nine months of 2006, we continued development drilling in the Greater Kuparuk Area, the Greater Prudhoe Area, the Alpine field and the West Sak development. We continued work on the construction of Alpine's first satellite fields, Nanuq and Fiord. The Fiord field began first production in August of 2006 and Nanuq is expected to start up in late 2006. In addition, expenditures were made to fund exploration activities, as well as to progress the construction of our fifth and final Endeavour Class tanker, which was christened in late October 2006.

We and our co-venturers in the Trans-Alaska Pipeline System also continued a project, which began in 2004, to upgrade the pipeline's pump stations. A phased startup of the project is expected to take place in the fourth quarter of 2006, with completion in 2007.

In July 2006, we announced the discovery and test production from the Qannik accumulation, the third satellite oil field overlying the Alpine field. We have a 78 percent interest in the Alpine field and its satellites.

Lower 48 States

In the Lower 48, capital expenditures during the first nine months of 2006 were focused onshore, with the development of natural gas reserves within our core areas, including the San Juan Basin of New Mexico, the Lobo Trend of South Texas, the Bossier Trend of East Texas, the Barnett Shale Trend of North Texas, and the Permian Basin of West Texas. In addition, capital was expended on our offshore operations for the continued development of the Ursa, Magnolia and K2 fields in the deepwater of the Gulf of Mexico.

CANADA

During the first nine months of 2006, we continued developing our Surmont heavy-oil project, where initial production is expected in the first half of 2007; and the Syncrude Stage III expansion-mining project in the Canadian province of Alberta, where the Syncrude upgrader expansion project was put into operation in May 2006 and became fully operational in the third quarter of 2006. In addition, capital expenditures were focused on development of our conventional oil and gas reserves in Western Canada and on progressing the Mackenzie Delta gas project.

VENEZUELA

In the Gulf of Paria, development drilling began on the Corocoro project in the second quarter of 2006. A floating storage and offloading vessel (FSO) is due to arrive in November and completion of pipelines and FSO mooring is expected in the fourth quarter of 2006. Field production is expected to commence in the third quarter of 2008 upon installation of the central processing platform.

NORTHWEST EUROPE

In the U.K. and Norwegian sectors of the North Sea, funds were invested during the first nine months of 2006 for development of the Britannia satellite fields—Callanish and Brodgar—where production is expected in 2007; continued development drilling on the Ekofisk Area growth project, where production began in October 2005; and the Alvheim project, where production is scheduled to begin in 2007.

In September 2006, we announced the Jasmine discovery, a new gas condensate field in the U.K. sector of the North Sea. Results from the discovery are being evaluated to determine the plan for appraisal drilling and development.

AFRICA AND MIDDLE EAST

In late-December 2005, we announced, in conjunction with our co-venturers, an agreement with the Libyan National Oil Corporation on the terms under which we would return to our former crude oil and natural gas production operations in the Waha concessions in Libya. The terms include a 25-year extension of the concessions to 2031-2034; a payment to the Libyan National Oil Corporation of $1.3 billion ($520 million net to ConocoPhillips) for the acquisition of an ownership interest in, and extension of, the concessions; and an estimated contribution to unamortized investments made since 1986 of $530 million ($212 million net to ConocoPhillips) that were agreed to be paid as part of the 1986 standstill agreement to hold the assets in escrow for the U.S.-based co-venturers. Of the total amount to be paid by ConocoPhillips, $520 million was paid in January 2006, with the balance expected to be paid in December 2006, following confirmation by audit.

Qatargas 3 is an integrated project comprised of upstream natural gas production facilities expected to produce natural gas from Qatar's North field over a 25-year life. The project also includes a 7.8-million-gross-ton-per-year LNG facility. LNG from the facility will be shipped from Qatar in a fleet of large LNG vessels, for sale primarily in the United States. The project is jointly owned by Qatar Petroleum (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent).

In the second quarter of 2006, we signed an interim agreement with affiliates of ExxonMobil and Qatar Petroleum to acquire an ownership interest in, and capacity utilization rights to, a planned LNG regasification facility and associated pipeline located on the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas (Golden Pass). Subject to the negotiation of a definitive joint-venture agreement, the proposed Golden Pass LNG regasification terminal would provide ConocoPhillips with regasification capacity for a substantial portion of the LNG produced from Qatargas 3. In addition to Golden Pass, the participants in Qatargas 3 continue to pursue other market alternatives for Qatargas 3 LNG production. The first LNG cargos are expected to be delivered from Qatargas 3 in 2009.

RUSSIA AND CASPIAN SEA

Russia

We have a 30 percent economic interest and a 50 percent voting interest in OOO Naryanmarneftegaz (NMNG), a joint venture with LUKOIL established in June 2005 to explore for and develop oil and gas resources in the northern part of Russia's Timan-Pechora province. We are working with LUKOIL, through NMNG, to develop the Yuzhno Khylchuyu (YK) field.

Caspian Sea

In the first nine months of 2006, we continued to participate in construction activities to develop the Kashagan field on the Republic of Kazakhstan shelf in the North Caspian Sea. We have a 9.26 percent interest in the North Caspian Sea Production Sharing Agreement, which includes the Kashagan field.

ASIA PACIFIC

Timor Sea

In the Timor Sea, we concluded the development of the Bayu-Undan natural gas project, as construction work and commissioning and startup activities of the onshore facility were all completed.

Indonesia
During the first nine months of 2006, we continued to invest funds to develop the Belanak, Kerisi, Hiu and North Belut fields in the South Natuna Sea Block B. In South Sumatra, we continued to develop the Suban Phase II project, which is an expansion of the existing Suban gas plant.

China
Work continued on the development of Phase II of the Peng Lai 19-3 oil field, as well as concurrent development of the nearby Peng Lai 25-6 field. The development of Peng Lai 19-3 and Peng Lai 25-6 will include multiple wellhead platforms and a larger floating production, storage and offloading vessel. Offshore installation work associated with the first new wellhead platform (WHP-C) began in the third quarter.

R&M

In the United States, we continued to expend funds related to clean fuels, safety and environmental projects during the first nine months of 2006. In addition, funds were spent on projects to improve light oil yields, lower crude costs and increase capacity at selected refineries.

Internationally, in February 2006, we announced the completion of the purchase of the Wilhelmshaven refinery in Wilhelmshaven, Germany. The purchase included the 260,000-barrel-per-day refinery, a marine terminal, rail and truck loading facilities, and a tank farm, as well as another entity, which provides commercial and administrative support to the refinery. The acquisition of the Wilhelmshaven refinery increased our overall international refining capacity by 60 percent, from 433,000 barrels per day to 693,000 barrels per day. In addition, we continued to invest in our ongoing refining and marketing operations outside the United States. The focus remained on upgrading and increasing profitability of our existing assets.

LUKOIL Investment

During the first nine months of 2006, we increased our ownership interest in LUKOIL to 19.0 percent at September 30, 2006, from 16.1 percent at December 31, 2005, based on authorized and issued shares. Purchases of LUKOIL shares to increase our ownership to 20 percent are expected to be completed by the end of 2006.

2006 Capital Budget

Our capital expenditures and investments budget for 2006 was increased to $17 billion in the second quarter of 2006. This amount now includes the capital program for Burlington Resources from March 31, 2006, through the remainder of the year, and the estimated investment necessary to bring our ownership in LUKOIL to 20 percent. In addition, we expect to provide loans of approximately $1 billion during 2006 to certain affiliated companies. See Note 9—Investments and Long-Term Receivables, in the Notes to the Consolidated Financial Statements, for additional information.

Contingencies

Legal and Tax Matters

We accrue for contingencies when a loss is probable and amounts can be reasonably estimated. Based on currently available information, we believe it is remote that future costs related to known contingent liability

exposures will exceed current accruals by an amount that would have a material adverse impact on our financial statements.

Environmental

We are subject to the same numerous international, federal, state, and local environmental laws and regulations, as other companies in the petroleum exploration and production industry; and refining, marketing and transportation of crude oil and refined products businesses. The most significant of these environmental laws and regulations include, among others, the:

- Federal Clean Air Act, which governs air emissions.
- Federal Clean Water Act, which governs discharges to water bodies.
- Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatened to occur.
- Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage, and disposal of solid waste.
- Federal Oil Pollution Act of 1990 (OPA90), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States.
- Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and responses departments.
- Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells.
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages.

These laws and their implementing regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also, in most cases, require permits in association with new or modified operations. These permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time-consuming. In addition, there can be delays associated with notice and comment periods and the agency's processing of the application. Many of the delays associated with the permitting process are beyond the control of the applicant.

We are also subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their state equivalents. Remediation obligations include cleanup responsibility arising from petroleum releases from underground storage tanks located at numerous past and present ConocoPhillips-owned and/or operated petroleum-marketing outlets throughout the United States. Federal and state laws require that contamination caused by such underground storage tank releases be assessed and remediated to meet applicable standards. In addition to other cleanup standards, many states have adopted cleanup criteria for methyl tertiary-butyl ether (MTBE) for both soil and groundwater. MTBE standards continue to evolve,

and future environmental expenditures associated with the remediation of MTBE-contaminated underground storage tank sites could be substantial.

At RCRA permitted facilities, we are required to assess environmental conditions. If conditions warrant, we may be required to remediate contamination caused by prior operations. In contrast to CERCLA, which is often referred to as "Superfund," the cost of corrective action activities under RCRA corrective action programs typically is borne solely by us. Over the next decade, we anticipate that significant ongoing expenditures for RCRA remediation activities may be required, but such annual expenditures for the near term are not expected to vary significantly from the range of such expenditures we have experienced over the past few years. Longer term, expenditures are subject to considerable uncertainty and may fluctuate significantly.

We, from time to time, receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging that we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2005, we reported we had been notified of potential liability under CERCLA and comparable state laws at 66 sites around the United States. At September 30, 2006, we had resolved eight of these sites and had received five new notices of potential liability, leaving 63 unresolved sites where we have been notified of potential liability.

For most Superfund sites, our potential liability will be significantly less than the total site remediation costs because the percentage of waste attributable to us, versus that attributable to all other potentially responsible parties, is relatively low. Although liability of those potentially responsible is generally joint and several for federal sites and frequently so for state sites, other potentially responsible parties at sites where we are a party typically have had the financial strength to meet their obligations, and where they have not, or where potentially responsible parties could not be located, our share of liability has not increased materially. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or attain a settlement of liability. Actual cleanup costs generally occur after the parties obtain EPA or equivalent state agency approval. There are relatively few sites where we are a major participant, and given the timing and amounts of anticipated expenditures, neither the cost of remediation at those sites nor such costs at all CERCLA sites, in the aggregate, is expected to have a material adverse effect on our competitive or financial condition.

Many states and foreign countries where we operate also have, or are developing, similar environmental laws and regulations governing these same types of activities. While similar, in some cases these regulations may impose additional, or more stringent, requirements that can add to the cost and difficulty of marketing or transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards, water quality standards and stricter fuel regulations, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change, are expected to continue to have an increasing impact on our operations in the United States and in other countries in which we operate.

Remediation Accruals
We accrue for remediation activities when it is probable that a liability has been incurred and reasonable estimates of the liability can be made. These accrued liabilities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except those assumed in a purchase business combination, which we do record on a discounted basis).

Many of these liabilities result from CERCLA, RCRA and similar state laws that require us to undertake certain investigative and remedial activities at sites where we conduct, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we have identified that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or state enforcement activities. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA. Considerable uncertainty exists with respect to these costs, and under adverse changes in circumstances, potential liability may exceed amounts accrued as of September 30, 2006.

Remediation activities vary substantially in duration and cost from site to site, depending on the mix of unique site characteristics, evolving remediation technologies, diverse regulatory agencies and enforcement policies, and the presence or absence of potentially liable third parties. Therefore, it is difficult to develop reasonable estimates of future site remediation costs.

At September 30, 2006, our balance sheet included a total environmental accrual of $1,034 million, compared with $989 million at December 31, 2005. We expect to incur a substantial majority of these expenditures within the next 30 years.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse effect upon our results of operations or financial position as a result of compliance with environmental laws and regulations.

NEW ACCOUNTING STANDARDS

In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, "Fair Value Measurements." This Statement defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We use fair value measurements to measure, among other items, purchased assets and investments, leases, derivative contracts and financial guarantees. We also use them to assess impairment of properties, plants and equipment, intangible assets and goodwill. The Statement does not apply to share-based payment transactions and inventory pricing. This Statement is effective January 1, 2008. We are currently evaluating the impact on our financial statements.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106 and 132(R)." This Statement requires an employer that sponsors one or more single-employer defined benefit plans to:

- Recognize the funded status of the benefit in its statement of financial position.
- Recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period, but are not recognized as components of net periodic benefit cost.

- Measure defined benefit plan assets and obligations as of the date of the employer's fiscal year end statement of financial position.
- Disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and the transition asset or obligation.

The provisions of this Statement are effective December 31, 2006, except for the requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end, which is effective December 31, 2008. We are currently evaluating the impact on our financial statements.

If SFAS No. 158 had been effective as of December 31, 2005, recorded plan assets would have been $68 million lower and recorded plan liabilities would have been $887 million higher, with corresponding offsets to other comprehensive income, deferred taxes, and intangible assets. Based on the latest information available, implementation of the new Statement at December 31, 2006, is expected to reduce recorded plan assets by about $70 million and increase recorded plan liabilities by approximately $750 million. The impact upon adoption at December 31, 2006, may differ substantially from this amount because our net plan liabilities are dependent upon future changes in interest rates, foreign currency exchange rates, the fair value of plan assets, and actuarial assumptions.

In June 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109." This Interpretation provides guidance on recognition, classification, and disclosure concerning uncertain tax liabilities. The evaluation of a tax position will require recognition of a tax benefit if it is more likely than not that it will be sustained upon examination. This Interpretation is effective beginning January 1, 2007. We are currently evaluating the impact on our financial statements.

In June 2006, the FASB ratified the consensus reached by the Emerging Issues Task Force (EITF) on Issue No. 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation)." The consensus requires disclosure of either the gross or net presentation, and any such taxes reported on a gross basis should be disclosed in the interim and annual financial statements. This Issue is effective for financial reports beginning after December 15, 2006. We do not expect to change our presentation of such taxes, and we will provide additional disclosure upon the adoption of the Issue.

OUTLOOK

EnCana Joint Ventures
In October 2006, we announced a business venture with EnCana Corporation (EnCana), to create an integrated North American heavy-oil business. The venture will consist of two 50/50 operating joint ventures, a Canadian upstream general partnership and a U.S. downstream limited liability company, with both EnCana and ourselves contributing equally-valued assets and equity. We expect to use the equity method of accounting for our investments in both joint ventures.

The upstream joint venture's operating assets will consist of EnCana's Foster Creek and Christina Lake steam-assisted gravity-drainage bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeast Alberta. EnCana will be operator and managing partner of the upstream joint venture. We expect to contribute $7.5 billion to this joint venture over a 10-year period beginning in 2007. This interest-bearing cash contribution obligation is expected to be recorded as a liability on our balance sheet at the close of the transaction.

The downstream joint venture will consist of our Wood River and Borger refineries, located in Roxana, Illinois, and Borger, Texas, respectively. This joint venture plans to expand heavy-oil processing capacity at these facilities from 60,000 barrels per day to approximately 550,000 barrels per day by 2015. Total crude oil throughput at these two facilities is expected to increase from the current 450,000 barrels per day to 600,000 barrels per day over the same time period. We will be the operator and managing partner of this downstream joint venture. EnCana is expected to contribute $7.5 billion, plus accrued interest to this joint venture over a 10-year period beginning in 2007. For the Wood River refinery, operating results will be shared 50/50 starting upon formation. For the Borger refinery, we will receive 85 percent of the operating results in 2007, 65 percent in 2008, and 50 percent in all years thereafter.

The transaction has received approval from Canadian authorities. Pending completion of U.S. regulatory review, the transaction is expected to close on January 2, 2007. Both companies' board of directors have approved the transaction.

Other

In October 2006, we announced we would invest approximately $400 million to expand the capacity at our Immingham Combined Heat and Power (CHP) plant in the United Kingdom by 450 Megawatts (MW), from 730 MW to 1,180 MW. Commercial operation of the expansion is currently expected to start in mid-2009.

In August 2006, we announced an agreement with the government of Dubai whereby our offshore oil concession would end effective April 2007. This agreement is not expected to have a material impact on our financial statements or proved reserves.

The progress of the Alaska natural gas pipeline project is likely to be deferred pending the election of a new governor and state legislature in the November 2006 general election. Discussions among the state of Alaska, ourselves and other North Slope producers are expected to resume once the newly elected officials are in office.

In August 2006, BP Exploration (Alaska) Inc., operator of the Prudhoe Bay Unit, announced it would initiate a phased shutdown of the Prudhoe Bay fields due to the discovery of a small leak in an oil sales line and concerns with pipeline corrosion. After completion of increased inspections and surveillance of the pipelines in the fields' western operating area, the shut down was limited to the eastern operating pipelines. The full year impact on our production is an estimated decrease of 9,000 barrels per day. The majority of the production has resumed, utilizing bypass lines from the Prudhoe Bay Unit to the Endicott Pipeline located nearby.

An increase in the Venezuelan income tax rate from 34 percent to 50 percent for heavy-oil projects was approved by the Venezuelan National Assembly in August of 2006, signed by the president of Venezuela in September, and published in the Official Gazette on September 25, 2006. The income tax rate increase is effective with the tax year beginning January 1, 2007. Additionally, government officials have made public statements about the goal of increasing government ownership interests in the upstream portion of heavy-oil projects to greater than 50 percent. The national oil company of Venezuela, Petroleos de Venezuela S.A., holds a 49.9 percent equity interest in the Petrozuata heavy-oil project and a 30 percent interest in the Hamaca heavy-oil project. We have a 50.1 percent interest and a 40 percent interest in the Petrozuata and Hamaca heavy-oil projects, respectively.

In July 2006, we announced the signing of a Memorandum of Understanding with International Petroleum Investment Company (IPIC) of Abu Dhabi to identify new upstream and downstream opportunities for joint investment. The parties also announced the signing of a Heads of Agreement to conduct a feasibility study for construction of a world scale refinery in Fujairah, United Arab Emirates. The refinery would have a capacity of 500,000 barrels per day and serve global markets.

In May 2006, we signed a Memorandum of Understanding with the Saudi Arabian Oil Company to conduct a detailed evaluation of a proposed development of a 400,000-barrel-per-day, full-conversion refinery in Yanbu, Saudi Arabia. The refinery would be designed to process Arabian heavy crude oil and produce high-quality, ultra-low-sulfur refined products.

In April 2006, we announced the commencement of an asset rationalization program to evaluate our asset base to identify those assets that may no longer fit into our strategic plans or those that could bring more value by being monetized in the near term. We expect this rationalization program to result in proceeds from asset dispositions of $3 billion to $4 billion when it is completed in 2007. In the third quarter of 2006, certain assets included in this program met the "held for sale" criteria of Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Although we expect the asset rationalization program to result in financial gains overall, in the third quarter of 2006, we recorded asset impairments of $266 million (before-tax) related to those assets meeting the "held for sale" criteria.

In E&P, we expect our production in the fourth quarter of 2006 to increase over third quarter levels reflecting the resumption of operations at Prudhoe Bay, normal seasonality, and less scheduled downtime in the United Kingdom and Venezuela. These positive impacts on production are expected to be partially offset by a reduction of approximately 25,000 barrels of oil equivalent (BOE) per day to 30,000 BOE per day related to the Bayu-Undan project in the Timor Sea due to the current higher-price environment resulting in an earlier-than-expected increase in the government share of production under the terms of the production sharing contract. In addition, in October 2006 the Organization of the Petroleum Exporting Countries (OPEC) announced an intention to reduce crude oil production by 1.2 million barrels per day (BPD), effective November 1, 2006. In response to this announcement, each of our Petrozuata and Hamaca heavy-oil project companies received notice from the Venezuelan Ministry of Energy and Petroleum that production from each of these projects would be reduced by 17,000 BPD beginning November 1, 2006, reducing our net share of current production by 7,100 BPD at Petrozuata and 5,700 BPD at Hamaca. Our production in other countries that participate in OPEC may be reduced as a result of this announcement.

In R&M, we expect our crude oil capacity utilization in the fourth quarter of 2006 to be similar to the third quarter.

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. You can identify our forward-looking statements by the words "anticipate," "estimate," "believe," "continue," "could," "intend," "may," "plan," "potential," "predict," "should," "will," "expect," "objective," "projection," "forecast," "goal," "guidance," "outlook," "effort," "target" and similar expressions.

We based the forward-looking statements relating to our operations on our current expectations, estimates and projections about ourselves and the industries in which we operate in general. We caution you that these statements are not guarantees of future performance and involve risks, uncertainties and assumptions that we cannot predict. In addition, we based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including the following:

- Fluctuations in crude oil, natural gas and natural gas liquids prices, refining and marketing margins and margins for our chemicals business.
- The operation and financing of our midstream and chemicals joint ventures.
- Potential failure or delays in achieving expected reserve or production levels from existing and future oil and gas development projects due to operating hazards, drilling risks and the inherent uncertainties in predicting oil and gas reserves and oil and gas reservoir performance.
- Unsuccessful exploratory drilling activities.
    - Failure of new products and services to achieve market acceptance.
- Unexpected changes in costs or technical requirements for constructing, modifying or operating facilities for exploration and production projects, manufacturing or refining.
- Unexpected technological or commercial difficulties in manufacturing, refining, or transporting our products, including synthetic crude oil and chemicals products.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, natural gas liquids, LNG and refined products.
- Inability to timely obtain or maintain permits, including those necessary for construction of LNG terminals or regasification facilities, comply with government regulations, or make capital expenditures required to maintain compliance.
- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future LNG and refinery projects and related facilities.
- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events or terrorism.
- International monetary conditions and exchange controls.
- Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.
- Liability resulting from litigation.
- General domestic and international economic and political developments, including armed hostilities, changes in governmental policies relating to crude oil, natural gas, natural gas liquids or refined product pricing and taxation, other political, economic or diplomatic developments, and international monetary fluctuations.
- Changes in tax and other laws, regulations or royalty rules applicable to our business.
- Inability to obtain economical financing for projects, construction or modification of facilities and general corporate purposes.
- Our ability to successfully integrate the operations of Burlington Resources into our own operations.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information about market risks for the nine months ended September 30, 2006, does not differ materially from that discussed under Item 7A of ConocoPhillips' Annual Report on Form 10-K for the year ended December 31, 2005.

Item 4. CONTROLS AND PROCEDURES

As of September 30, 2006, with the participation of our management, our Chairman, President and Chief Executive Officer (principal executive officer) and our Executive Vice President, Finance, and Chief Financial Officer (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Securities Exchange Act of 1934, as amended (the Act), of the effectiveness of the design and operation of ConocoPhillips' disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman, President and Chief Executive Officer and our Executive Vice President, Finance, and Chief Financial Officer concluded that our disclosure controls and procedures were operating effectively as of September 30, 2006.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the third quarter of 2006 and any material developments with respect to those matters previously reported in ConocoPhillips' 2005 Form 10-K or first or second quarter 2006 Forms 10-Q. While it is not possible to accurately predict the final outcome of these pending proceedings, if any one or more of such proceedings were decided adversely to ConocoPhillips, we expect there would be no material effect on our consolidated financial position. Nevertheless, such proceedings are reported pursuant to the U.S. Securities and Exchange Commission's regulations.

Matters Previously Reported
In July and August 2005, the South Coast Air Quality Management District (SCAQMD) performed inspections at our Los Angeles refinery in Wilmington and Carson, California, focusing on our leak detection and repair program for fugitive emissions as required under SCAQMD rules. As a result of these inspections, the SCAQMD alleged that we violated certain rules related to the leak detection and repair program. The company has settled these matters and paid a civil penalty of $2,252,000 and $300,000 in emissions fees.

On October 19, 2005, the Bay Area Air Quality Management District (BAAQMD) notified us of their intent to seek civil penalties in the amount of $108,000 for 18 alleged violations of various BAAQMD regulations at our Rodeo facility and carbon plant located in the San Francisco area that occurred between February 2005 and July 2005. We reached agreement with BAAQMD to settle this matter for $96,000 and concluded the settlement in October 2006.

On November 22, 2005, the BAAQMD entered into a compliance and enforcement agreement with our Rodeo facility located in the San Francisco area to coordinate enforcement of BAAQMD leak detection and repair (LDAR) requirements with the federal program as provided in the ConocoPhillips Consent Decree with the United States Environmental Protection Agency (U.S. District Court for the Southern District of Texas, Civil Action No. H-05-0258). The Consent Decree required, among other things, that the Rodeo facility perform certain third-party audits of the LDAR program to identify noncompliance. The BAAQMD agreed to a schedule of penalties for noncompliance found during LDAR audits with a maximum cap of $100,000. In the first quarter of 2006, the Rodeo facility performed certain LDAR audits, and found certain noncompliance items. We reached an agreement with BAAQMD to settle this matter for $100,000 and concluded the settlement in October 2006.

The U.S. Coast Guard and Washington State Department of Ecology investigated the possible sources of an oil spill in Puget Sound. In November 2004, the U.S. Attorney and the U.S. Coast Guard offices in Seattle, Washington, issued subpoenas to Polar Tankers, Inc., a subsidiary of ConocoPhillips Company, for records related to the vessel Polar Texas. On December 23, 2004, the governor of the state of Washington and the U.S. Coast Guard publicly announced that they believed the Polar Texas was the source of the spill. The company fully cooperated with the investigations. The U.S. Attorney’s Office in Seattle declined prosecution of the company. Polar Tankers, ConocoPhillips and the state of Washington settled the matter, with payment of civil penalties in the amount of $540,000. Additionally, the company has agreed to pay the federal government $2.2 million to cover the cost of the spill clean-up, and $80,000 in civil penalties. The settlement did not include any admission of liability. The company and the authorities remain in active settlement negotiations around other remaining items.

On June 30, 2006, the Texas Commission on Environmental Quality (TCEQ) issued a Notice of Enforcement (NOE) to ConocoPhillips’ Sweeny refinery. The NOE alleges that stack tests performed on the Sweeny Unit 3 Fluid Catalytic Cracking Regenerator showed noncompliance with the requirements of a TCEQ permit and federal air toxics (MACT) regulations. We have been informed by the TCEQ that they intend to combine this NOE with two others relating to alleged technical stack testing deficiencies and an excess emission event. On September 4, 2006, we resolved this matter with a payment penalty of $91,808.

<u>New Matter</u>
In September 2006, the San Luis Obispo Air Pollution Control District (SLOAPCD) issued a demand to settle four Notices of Violation (NOVs) issued between May and August 2006 with respect to our Santa Maria facility, a part of our San Francisco area refinery. The NOVs allege we: exceeded green coke feed limit on 17 separate days; failed to timely submit a second quarter 2006 report; failed to sample and analyze certain air emissions; and exceeded carbon plant pressure limits for three days. SLOAPCD’s initial monetary demand is $143,000 to settle all four NOVs. We are working with SLOAPCD to resolve this matter.

Item 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in the “Risk Factors” section of our Annual Report on Form 10-K for the year ended December 31, 2005.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased*		Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**		Millions of Dollars Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
July 1-31, 2006	8,420	$	67.85	—	$	651
August 1-31, 2006	2,110,871		66.88	2,108,000		510
September 1-30, 2006	1,815,360		60.09	1,814,300		401
Total	3,934,651	$	63.75	3,922,300		

* *Includes the repurchase of common shares from company employees in connection with the company’s broad-based employee incentive plans.*

** *On February 4, 2005, we announced a stock repurchase program that provided for the repurchase of up to $1 billion of the company’s common stock over a period of up to two years, which was completed in August 2005. A second repurchase program that provides for the repurchase of up to $1 billion of the company’s common stock over a period of up to two years was announced on August 11, 2005, which was completed in April 2006. A third repurchase program that provides for the repurchase of up to $1 billion of the company’s common stock over a period of up to two years was announced on November 15, 2005. Acquisitions for the share repurchase programs are made at management’s discretion, at prevailing prices, subject to market conditions and other factors. Purchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plans are initially held as treasury shares.*

Item 6. EXHIBITS

<u>Exhibits</u>

10.1 Description of Amendments to Non-Employee Director Compensation (incorporated by reference to Item 1.01 of the Current Report of

ConocoPhillips on Form 8-K filed October 6, 2006).

12	Computation of Ratio of Earnings to Fixed Charges.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32	Certifications pursuant to 18 U.S.C. Section 1350.
99	Unaudited Pro Forma Combined Statement of Income for the nine months ended September 30, 2006.

SIGNATURE

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

CONOCOPHILLIPS

/s/ Rand C. Berney

Rand C. Berney
Vice President and Controller
(Chief Accounting and Duly Authorized Officer)

November 1, 2006

Exhibit 12

CONOCOPHILLIPS AND CONSOLIDATED SUBSIDIARIES
TOTAL ENTERPRISE

Computation of Ratio of Earnings to Fixed Charges

		Millions of Dollars Nine Months Ended September 30	
		2006	2005
		(Unaudited)	
Earnings Available for Fixed Charges			
Income from continuing operations before income taxes	$	**22,416**	16,926
Distributions less than equity in earnings of fifty-percent-or-less-owned companies		**(1,022)**	(1,699)
Fixed charges, excluding capitalized interest*		**995**	561
	$	**22,389**	15,788
Fixed Charges			
Interest and debt expense, excluding capitalized interest	$	**783**	387
Capitalized interest		**328**	281
Interest portion of rental expense		**141**	130
Interest expense relating to guaranteed debt of fifty-percent-or-less-owned companies		**2**	0
	$	**1,254**	798
Ratio of Earnings to Fixed Charges		**17.9**	19.8

**Includes amortization of capitalized interest totaling approximately $69 million in 2006 and $44 million in 2005.*

Earnings available for fixed charges include, if any, our equity in losses of companies owned less than fifty percent and having debt for which the company is contingently liable. Fixed charges include our proportionate share, if any, of interest relating to the contingent debt.

Earnings available for fixed charges include, if any, 100 percent of the losses of companies owned greater than fifty percent that have debt for which we are contingently liable. Fixed charges include 100 percent of interest and capitalized interest, if any, relating to the contingent debt.

Exhibit 31.1

CERTIFICATION

I, James J. Mulva, certify that:

1. I have reviewed this quarterly report on Form 10-Q of ConocoPhillips;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 1, 2006

/s/ James J. Mulva
James J. Mulva
Chairman, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, John A. Carrig, certify that:

1. I have reviewed this quarterly report on Form 10-Q of ConocoPhillips;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: November 1, 2006

/s/ John A. Carrig

John A. Carrig
Executive Vice President, Finance, and
Chief Financial Officer

Exhibit 32

CERTIFICATIONS PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the Quarterly Report of ConocoPhillips (the company) on Form 10-Q for the period ended September 30, 2006, as filed with the U.S. Securities and Exchange Commission on the date hereof (the Report), each of the undersigned hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to their knowledge:

(1) The Report fully complies with the requirements of Sections 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the company.

Date: November 1, 2006

/s/ James J. Mulva
James J. Mulva
Chairman, President and Chief Executive Officer

/s/ John A. Carrig
John A. Carrig
Executive Vice President, Finance, and Chief Financial Officer

Unaudited Pro Forma Combined Statement of Income

On March 31, 2006, ConocoPhillips completed the acquisition of Burlington Resources Inc. (BR). The following unaudited pro forma financial statement combines the unaudited, historical consolidated statement of income of Burlington Resources for the three months ended March 31, 2006, with the unaudited, historical consolidated statement of income of ConocoPhillips for the nine months ended September 30, 2006, giving effect to the acquisition using the purchase method of accounting. The unaudited pro forma combined statement of income assumes the acquisition was effected on January 1, 2006. The accounting policies of ConocoPhillips and BR were comparable.

The unaudited pro forma combined statement of income is for illustrative purposes only. The financial results may have been different had the companies always been combined. Further, the unaudited pro forma combined statement of income does not reflect anticipated synergies resulting from the acquisition. You should not rely on the pro forma combined statement of income as being indicative of the historical results that would have been achieved had the companies always been combined or the future results that ConocoPhillips will experience.

UNAUDITED PRO FORMA COMBINED STATEMENT OF INCOME

	Millions of Dollars			
Nine Months Ended September 30, 2006	ConocoPhillips	BR*	Pro Forma Adjustments	ConocoPhillips and BR Pro Forma Combined
Revenues and Other Income				
Sales and other operating revenues	$ 142,131	2,124	(219)(a)	144,036
Equity in earnings of affiliates	3,320	1	—	3,321
Other income	537	50	—	587
Total Revenues and Other Income	145,988	2,175	(219)	147,944
Costs and Expenses				
Purchased crude oil, natural gas and products	93,454	—	(219)(a)	93,235
Production and operating expenses	7,549	336	—	7,885
Selling, general and administrative expenses	1,826	79	—	1,905
Exploration expenses	443	67	—	510
Depreciation, depletion and amortization	5,282	390	336(b)	6,008
Property impairments	317	—	—	317
Taxes other than income taxes	13,661	112	—	13,773
Accretion on discounted liabilities	207	9	—	216
Interest and debt expense	783	72	174(c)	1,029
Foreign currency transaction losses (gains)	(10)	(2)	—	(12)
Minority interests	60	—	—	60
Total Costs and Expenses	123,572	1,063	291	124,926
Income from continuing operations before income taxes	22,416	1,112	(510)	23,018
Provision for income taxes	10,063	368	(160)(d)	10,271
Income From Continuing Operations	12,353	744	(350)	12,747
Income From Continuing Operations Per Share of Common Stock (dollars)				
Basic	7.90			7.71
Diluted	7.78			7.60
Average Common Shares Outstanding (in thousands)				
Basic	1,564,423			1,653,566 (e)
Diluted	1,587,892			1,677,968 (e)

**Three months ended March 31, 2006.*

Notes to Unaudited Pro Forma Combined Condensed Financial Statements

(a) Reflects the elimination of sales from BR to ConocoPhillips.

(b) Reflects increased depreciation, depletion and amortization related to the “step-up” of properties, plants and equipment to their estimated fair value. Producing properties, grouped at a BR divisional level in the United States and by country internationally, were assigned first-year unit-of-production depreciation rates ranging from 5 percent to 25 percent, while pooled leaseholds and corporate assets were assigned straight-line depreciation rates ranging from five to 25 years.

(c) Reflects: 1) the increase in long-term debt to fund the cash portion of the purchase price at ConocoPhillips’ current borrowing interest rate of 5.58 percent, and 2) the restatement of BR’s debt to fair value as of March 31, 2006, and the corresponding reduction in interest expense as the resulting $442 million premium is amortized over a weighted-average effective yield period of 12 years. A one-eighth percent increase in the average borrowing rate would increase before-tax pro-forma-basis interest expense by $4 million.

(d) The pro forma adjustment to income tax reflects the statutory federal and state income tax impacts of the pro forma adjustments to BR's pretax income, and also includes the estimated effect of the acquisition on ConocoPhillips' interest expense allocated to foreign sources.

(e) Reflects the exchange of outstanding BR stock, the issuance of 270.4 million shares of ConocoPhillips common stock (including 32.1 million treasury shares) issued to BR stockholders as consideration in the merger, and, for diluted average common shares outstanding, the effect of ConocoPhillips stock options issued in the exchange to BR stock option holders, as well as non-vested restricted stock.