WILLIAMS COMPANIES INC
Form 10-Q
May 01, 2008

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2008

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 1-4174

THE WILLIAMS COMPANIES, INC.

(Exact name of registrant as specified in its charter)

DELAWARE	73-0569878
(State of Incorporation)	(IRS Employer Identification Number)
ONE WILLIAMS CENTER, TULSA, OKLAHOMA	74172
(Address of principal executive office)	(Zip Code)

Registrant s telephone number: (918) 573-2000

NO CHANGE

Former name, former address and former fiscal year, if changed since last report.

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 þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company 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 þ

Indicate the number of shares outstanding of each of the issuer s classes of common stock as of the latest practicable date.

Class	Outstanding at April 29, 2008
Common Stock, $1 par value	584,409,221 Shares

The Williams Companies, Inc.
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Certain matters contained in this report include forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These statements discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

All statements, other than statements of historical facts, included in this report which address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as anticipates, believes, could, may, should, continues, estimates, expects, forecasts, might, planned, potential, projects, expressions. These forward-looking statements include, among others, statements regarding:

amounts and nature of future capital expenditures;

expansion and growth of our business and operations;

business strategy;

estimates of proved gas and oil reserves;

reserve potential;

development drilling potential;

cash flow from operations or results of operations;

seasonality of certain business segments;

natural gas and natural gas liquids prices and demand.

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Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this document. Many of the factors that will determine these results are beyond our ability to control or project. Specific factors which could cause actual results to differ from those in the forward-looking statements include:

- availability of supplies (including the uncertainties inherent in assessing and estimating future natural gas reserves), market demand, volatility of prices, and increased costs of capital;
- inflation, interest rates, fluctuation in foreign exchange, and general economic conditions;
- the strength and financial resources of our competitors;
- development of alternative energy sources;
- the impact of operational and development hazards;
- costs of, changes in, or the results of laws, government regulations including proposed climate change legislation, environmental liabilities, litigation, and rate proceedings;
- changes in the current geopolitical situation;
- risks related to strategy and financing, including restrictions stemming from our debt agreements and future changes in our credit ratings;
- risks associated with future weather conditions;
- acts of terrorism.

Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. We disclaim any obligations to and do not intend to update the above list to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions, or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part I, Item IA. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2007, and Part II, Item 1A. Risk Factors of this Form 10-Q.

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The Williams Companies, Inc.
Consolidated Statement of Income
(Unaudited)

(Dollars in millions, except per-share amounts)	Three months ended March 31, 2008	2007
Revenues:		
Exploration & Production	$ 748	$ 483
Gas Pipeline	413	371
Midstream Gas & Liquids	1,557	1,002
Gas Marketing Services	1,650	1,288
Other	6	7
Intercompany eliminations	(1,150)	(783)
Total revenues	3,224	2,368
Segment costs and expenses:		
Costs and operating expenses	2,373	1,843
Selling, general and administrative expenses	111	102
Other income net	(117)	(18)
Total segment costs and expenses	2,367	1,927
General corporate expenses	42	40
Operating income (loss):		
Exploration & Production	427	183
Gas Pipeline	170	141
Midstream Gas & Liquids	238	147
Gas Marketing Services	21	(30)
Other	1	
General corporate expenses	(42)	(40)
Total operating income	815	401
Interest accrued	(165)	(172)
Interest capitalized	8	5
Investing income	55	52
Minority interest in income of consolidated subsidiaries	(39)	(14)
Other income net	5	2
Income from continuing operations before income taxes	679	274
Provision for income taxes	263	104

Income from continuing operations	416	170
Income (loss) from discontinued operations	84	(36)
Net income	$ 500	$ 134
Basic earnings (loss) per common share:		
Income from continuing operations	$ .71	$ .28
Income (loss) from discontinued operations	.14	(.06)
Net income	$ .85	$ .22
Weighted-average shares (thousands)	585,518	598,031
Diluted earnings (loss) per common share:		
Income from continuing operations	$ .70	$ .28
Income (loss) from discontinued operations	.14	(.06)
Net income	$ .84	$ .22
Weighted-average shares (thousands)	598,627	611,470
Cash dividends declared per common share	$ .10	$ .09

See accompanying notes.

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The Williams Companies, Inc.
Consolidated Balance Sheet
(Unaudited)

(Dollars in millions, except per-share amounts)	March 31, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,240	$ 1,699
Accounts and notes receivable (net of allowance of $27 at March 31, 2008 and December 31, 2007)	1,334	1,192
Inventories	289	209
Derivative assets	2,813	1,736
Assets of discontinued operations	61	185
Deferred income taxes	160	199
Other current assets and deferred charges	255	318
Total current assets	7,152	5,538
Investments	917	901
Property, plant and equipment net	16,257	15,981
Derivative assets	1,129	859
Goodwill	1,011	1,011
Other assets and deferred charges	706	771
Total assets	$ 27,172	$ 25,061
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 1,285	$ 1,131
Accrued liabilities	1,114	1,158
Derivative liabilities	3,129	1,824
Liabilities of discontinued operations	51	175
Long-term debt due within one year	85	143
Total current liabilities	5,664	4,431
Long-term debt	7,799	7,757
Deferred income taxes	3,039	2,996
Derivative liabilities	1,358	1,139
Other liabilities and deferred income	928	933
Contingent liabilities and commitments (Note 12)		
Minority interests in consolidated subsidiaries	583	1,430
Stockholders equity:		
Common stock (960 million shares authorized at $1 par value; 609 million issued at March 31, 2008 and 608 million shares issued at December 31, 2007)	609	608

Capital in excess of par value	7,999	6,748
Retained earnings (deficit)	148	(293)
Accumulated other comprehensive loss	(262)	(121)
	8,494	6,942
Less treasury stock, at cost (25 million shares of common stock at March 31, 2008 and 22 million shares of common stock at December 31, 2007)	(693)	(567)
Total stockholders equity	7,801	6,375
Total liabilities and stockholders equity	$ 27,172	$ 25,061

See accompanying notes.

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The Williams Companies, Inc.
Consolidated Statement of Cash Flows
(Unaudited)

(Dollars in millions)	Three months ended March 31, 2008	2007
OPERATING ACTIVITIES:		
Net income	$ 500	$ 134
Adjustments to reconcile to net cash provided by operations:		
Depreciation, depletion and amortization	302	248
Provision for deferred income taxes	153	73
Provision for loss on investments, property and other assets	2	4
Net gain on disposition of assets	(2)	(1)
Gain on sale of contractual production rights	(118)	
Minority interest in income of consolidated subsidiaries	39	14
Amortization of stock-based awards	(15)	17
Cash provided (used) by changes in current assets and liabilities:		
Accounts and notes receivable	(62)	(62)
Inventories	(80)	(25)
Margin deposits and customer margin deposits payable	38	35
Other current assets and deferred charges	8	3
Accounts payable	98	3
Accrued liabilities	(87)	(189)
Changes in current and noncurrent derivative assets and liabilities	(19)	68
Other, including changes in noncurrent assets and liabilities	36	(23)
Net cash provided by operating activities	793	299
FINANCING ACTIVITIES:		
Proceeds from long-term debt	100	
Payments of long-term debt	(115)	(119)
Proceeds from issuance of common stock	6	14
Proceeds from sale of limited partner units of consolidated partnerships	362	
Tax benefit of stock-based awards	10	8
Dividends paid	(59)	(54)
Purchase of treasury stock	(93)	
Dividends and distributions paid to minority interests	(24)	(20)
Changes in restricted cash	7	35
Changes in cash overdrafts	(31)	17
Other net	(1)	3
Net cash provided (used) by financing activities	162	(116)
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(579)	(509)

Net proceeds from dispositions	3	
Changes in accounts payable and accrued liabilities	43	(6)
Proceeds from sale of discontinued operations	8	
Purchases of investments/advances to affiliates	(20)	(21)
Purchases of auction rate securities		(173)
Proceeds from sales of auction rate securities		45
Proceeds from sale of contractual production rights	118	
Proceeds from dispositions of investments and other assets	14	18
Other net	(1)	5
Net cash used by investing activities	(414)	(641)
Increase (decrease) in cash and cash equivalents	541	(458)
Cash and cash equivalents at beginning of period	1,699	2,269
Cash and cash equivalents at end of period	$ 2,240	$ 1,811

See accompanying notes.

The Williams Companies, Inc.
Notes to Consolidated Financial Statements
(Unaudited)

Note 1. General

Our accompanying interim consolidated financial statements do not include all the notes in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto in our Annual Report on Form 10-K. The accompanying unaudited financial statements include all normal recurring adjustments that, in the opinion of our management, are necessary to present fairly our financial position at March 31, 2008, and results of operations and cash flows for the three months ended March 31, 2008 and 2007.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Note 2. Basis of Presentation

Discontinued Operations

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, the accompanying consolidated financial statements and notes reflect the results of operations and financial position of our former power business as discontinued operations. (See Note 3.) These operations included a 7,500-megawatt portfolio of power-related contracts that was sold in 2007 to Bear Energy, LP, a unit of the Bear Stearns Company, Inc., and our natural gas-fired electric generating plant located in Hazleton, Pennsylvania (Hazleton) that was sold in March 2008, in addition to other power-related assets.

Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to our continuing operations.

Master Limited Partnerships

We currently own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. Considering the presumption of control of the general partner in accordance with Emerging Issues Task Force (EITF) Issue No. 04-5, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights, Williams Partners L.P. is consolidated within our Midstream Gas & Liquids (Midstream) segment.

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering of 16.25 million common units at a price of $20 per unit. In February 2008, the underwriters exercised their right to purchase an additional 1.65 million common units at the same price. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP (Northwest Pipeline). Upon completion of these transactions, we now hold approximately 47.7 percent of the interests in Williams Pipeline Partners L.P., including the interests of the general partner which is wholly owned by us, and incentive distribution rights. In accordance with EITF Issue No. 04-5, Williams Pipeline Partners L.P. will continue to be consolidated within our Gas Pipeline segment due to our control through the general partner.

Note 3. Discontinued Operations

The summarized results of discontinued operations and summarized assets and liabilities of discontinued operations primarily reflect our former power business except where noted otherwise.

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Notes (Continued)

Summarized Results of Discontinued Operations

The following table presents the summarized results of discontinued operations for the three months ended March 31, 2008 and 2007.

	Three months ended March 31, 2008	Three months ended March 31, 2007
	(Millions)	
Revenues	$	$ 484
Income (loss) from discontinued operations before income taxes	$ 132	$ (57)
Benefit (provision) for income taxes	(48)	21
Income (loss) from discontinued operations	$ 84	$ (36)

In first-quarter 2008, we recognized pre-tax income of approximately $128 million in *income (loss) from discontinued operations before income taxes* related to our former Alaska operations. This amount includes $74 million related to cash received upon the favorable resolution of a matter involving pipeline transportation rates and $54 million related to a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank. (See Note 12.)

Summarized Assets and Liabilities of Discontinued Operations

The following table presents the summarized assets and liabilities of discontinued operations as of March 31, 2008 and December 31, 2007. The March 31, 2008, and December 31, 2007, balances for *derivative assets* and *derivative liabilities* represent contracts remaining to be assigned to Bear Energy, LP, entirely offset by reciprocal positions with Bear Energy, LP. We continue to pursue assignment of the remaining contracts. The December 31, 2007, balance of *property, plant and equipment net* includes Hazleton. These assets were sold in a March 2008 transaction for approximately $8 million.

	March 31, 2008	December 31, 2007
	(Millions)	
Derivative assets	$ 16	$ 114
Accounts receivable net	37	55
Other current assets	3	3
Total current assets	56	172
Property, plant and equipment net		8
Other noncurrent assets	5	5
Total noncurrent assets	5	13
Total assets	$ 61	$ 185
Derivative liabilities	$ 16	$ 114
Other current liabilities	35	61

Total current liabilities	51	175
Total liabilities	$ 51	$ 175

Note 4. Asset Sales and Other Accruals

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments. We recognized a pre-tax gain of approximately $118 million in the first quarter of 2008 related to the initial cash received, which is reflected in *other income net* within *segment costs and expenses* at Exploration & Production. Any additional cash received from escrow will be recognized as income when received.

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Notes (Continued)

Note 5. Provision for Income Taxes

The *provision for income taxes* includes:

	Three months ended March 31, 2008	2007
	(Millions)	
Current:		
Federal	$ 108	$ 3
State	17	(2)
Foreign	14	9
	139	10
Deferred:		
Federal	102	75
State	16	13
Foreign	6	6
	124	94
Total provision	$ 263	$ 104

The effective income tax rates for the three months ended March 31, 2008 and 2007, are greater than the federal statutory rate due primarily to the effect of state income taxes and taxes on foreign operations.

During the next twelve months, we do not expect settlement of any unrecognized tax benefit associated with domestic or international matters under audit to have a material impact on our financial position.

Note 6. Earnings Per Common Share from Continuing Operations

Basic and diluted earnings per common share are computed as follows:

	Three months ended March 31, 2008	2007
	(Dollars in millions, except per share amounts; shares in thousands)	
Income from continuing operations available to common stockholders for basic and diluted earnings per share (1)	$ 416	$ 170
Basic weighted-average shares (2)	585,518	598,031
Effect of dilutive securities:		
Nonvested restricted stock units (3)	1,465	1,363
Stock options	4,325	4,751
Convertible debentures	7,319	7,325
Diluted weighted-average shares	598,627	611,470

Earnings per common share from continuing operations:				
Basic	$	.71	$	.28
Diluted	$	.70	$	.28

(1) The three months ended March 31, 2008 and 2007 both include $1 million of interest expense, net of tax, associated with our convertible debentures. These amounts have been added back to *income from continuing operations available to common stockholders* to calculate diluted earnings per common share.

(2) Since third-quarter 2007, we have purchased approximately 20 million shares of our common stock under a stock repurchase program (see Note 11).

(3) The nonvested restricted stock units outstanding at March 31, 2008, will vest over the period from April 2008 to January 2012.

The table below includes information related to stock options that were outstanding at March 31 of each respective year but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the first quarter weighted-average market price of our common shares.

	March 31, 2008	March 31, 2007
Options excluded (millions)	2.2	4.4
Weighted-average exercise prices of options excluded	$ 37.10	$ 34.19
Exercise price ranges of options excluded	$ 34.54 - $42.29	$ 27.15 - $42.29
First quarter weighted-average market price	$ 33.97	$ 27.04

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Notes (Continued)

Note 7. Employee Benefit Plans

Net periodic benefit expense for the three months ended March 31, 2008 and 2007 is as follows:

	Pension Benefits Three months ended March 31, 2008	Pension Benefits Three months ended March 31, 2007	Other Postretirement Benefits Three months ended March 31, 2008	Other Postretirement Benefits Three months ended March 31, 2007
	(Millions)			
Components of net periodic benefit expense:				
Service cost	$ 5	$ 6	$ 1	$ 1
Interest cost	14	13	4	4
Expected return on plan assets	(20)	(18)	(3)	(3)
Amortization of net actuarial loss	2	4		
Regulatory asset amortization			1	1
Net periodic benefit expense	$ 1	$ 5	$ 3	$ 3

During the first quarter of 2008, we have not contributed to our pension plans. We presently anticipate making contributions of approximately $41 million to our pension plans in the remainder of 2008. During the first quarter of 2008, we have contributed $4 million to our other postretirement benefit plans. We presently anticipate making additional contributions of approximately $11 million to our other postretirement benefit plans in 2008 for a total of approximately $15 million.

Note 8. Inventories

Inventories at March 31, 2008 and December 31, 2007 are as follows:

	March 31, 2008	December 31, 2007
	(Millions)	
Natural gas liquids	$ 133	$ 66
Natural gas in underground storage	55	45
Materials, supplies and other	101	98
	$ 289	$ 209

Note 9. Debt and Banking Arrangements

Long-Term Debt

Revolving credit and letter of credit facilities (credit facilities)

At March 31, 2008, Northwest Pipeline has $250 million and Transcontinental Gas Pipeline (Transco) has $100 million in loans outstanding under our $1.5 billion unsecured credit facility. Letters of credit issued under our credit facilities are:

Letters of Credit at

	March 31, 2008 (Millions)
$500 million unsecured credit facilities	$ 238
$700 million unsecured credit facilities	$ 41
$1.5 billion unsecured credit facility	$ 28

Issuances and retirements

On January 15, 2008, Transco retired $100 million of 6.25 percent senior unsecured notes due January 15, 2008, with the previously mentioned proceeds borrowed on our $1.5 billion unsecured credit facility.

Transco s $75 million adjustable rate unsecured note, due April 15, 2008, was reclassified as long-term debt as a result of a refinancing in April 2008 under our $1.5 billion unsecured credit facility.

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Note 10. Fair Value Measurements

Adoption of SFAS No. 157

SFAS No. 157, Fair Value Measurements (SFAS 157), establishes a framework for fair value measurements in the financial statements by providing a definition of fair value, provides guidance on the methods used to estimate fair value and expands disclosures about fair value measurements. On January 1, 2008, we applied SFAS 157 for our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. Upon applying SFAS 157, we changed our valuation methodology to consider our nonperformance risk in estimating the fair value of our liabilities. The initial adoption of SFAS 157 had no material impact on our Consolidated Financial Statements. In February 2008, the FASB issued FASB Staff Position (FSP) FAS 157-2, permitting entities to delay application of SFAS 157 to fiscal years beginning after November 15, 2008, for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Beginning January 1, 2009, we will apply SFAS 157 fair value requirements to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed on a recurring basis. SFAS 157 requires two distinct transition approaches: (1) cumulative-effect adjustment to beginning retained earnings for certain financial instrument transactions and (2) prospectively as of the date of adoption through earnings or other comprehensive income, as applicable for all other instruments. Upon adopting SFAS 157, we applied a prospective transition as we did not have financial instrument transactions that required a cumulative-effect adjustment to beginning retained earnings.

Fair value is the price that would be received to sell an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market based measurement considered from the perspective of a market participant. We use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. We primarily apply a market approach for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices in active markets for identical assets or liabilities that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 primarily consists of financial instruments that are exchange-traded, including certain instruments that were part of sales transactions in 2007 and remain to be assigned to the purchaser. These unassigned instruments are entirely offset by reciprocal positions entered into directly with the purchaser. These reciprocal positions have also been included in Level 1.

Level 2 Inputs are other than quoted prices in active markets included in Level 1, that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. Our Level 2 primarily consists of over-the-counter (OTC) instruments such as forwards and swaps.

Level 3 Includes inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management s best estimate of the assumptions market participants would use in determining fair value. Our Level 3 consists of instruments valued using industry standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall fair value. Instruments in this category primarily include OTC options. At each balance sheet date, we perform an analysis of all instruments subject to recurring fair value measurement and include in Level 3 all of those whose fair value is based on significant unobservable inputs.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of

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the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

The following table sets forth by level within the fair value hierarchy our assets and liabilities that are measured at fair value on a recurring basis.

Fair Value Measurements at March 31, 2008 Using:
(Millions)

	Quoted Prices in Active Markets for Identical Assets or Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Energy derivatives	$ 1,267	$ 2,432	$ 243	$ 3,942
Other assets			10	10
Total assets	$ 1,267	$ 2,432	$ 253	$ 3,952
Liabilities:				
Energy derivatives	$ 1,219	$ 2,839	$ 429	$ 4,487
Total liabilities	$ 1,219	$ 2,839	$ 429	$ 4,487

Energy derivatives include commodity based exchange-traded contracts and OTC contracts. Exchange-traded contracts include futures and options. OTC contracts include forwards, swaps and options.

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value also incorporates other factors including the credit standing of the counterparties involved, our nonperformance risk on our liabilities, the impact of credit enhancements (such as cash deposits and letters of credit) and the time value of money.

Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets and are classified within Level 1.

Contracts for which fair value can be estimated from executed transactions or broker quotes corroborated by other market data are generally classified within Level 2. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

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Certain instruments trade in less active markets with lower availability of pricing information requiring valuation models using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The fair value of options is estimated using an industry standard Black-Scholes option pricing model. Certain inputs into the model are generally observable, such as commodity prices and interest rates, whereas a significant model input, implied volatility by location, is unobservable and requires judgment in estimating.

The following table sets forth a reconciliation of changes in the fair value of net derivatives and other assets classified as Level 3 in the fair value hierarchy for the period January 1, 2008 through March 31, 2008.

Fair Value Measurements Using Significant Unobservable Inputs
(Level 3)
(Millions)

	Net Derivatives	Other Assets
Balance as of January 1, 2008	$ (14)	$ 10
Realized and unrealized gains (losses):		
Included in *income from continuing operations*	3	
Included in *other comprehensive income (loss)* (See Note 13)	(177)	
Purchases, issuances, and settlements	3	
Transfers in/(out) of Level 3	(1)	
Balance as of March 31, 2008	$ (186)	$ 10
Unrealized gains (losses) included in *income from continuing operations* relating to instruments still held at March 31, 2008	$ 1	$

Realized and unrealized gains (losses) included in *income from continuing operations* for the above period are reported in *revenues* in our Consolidated Statement of Income.

Note 11. Stockholders Equity

In first-quarter 2008, we purchased approximately 4 million shares of our common stock for $126 million under our $1 billion common stock repurchase program at an average cost of $33.95 per share. Since the program s inception in third-quarter 2007, we have purchased approximately 20 million shares of our common stock for approximately $652 million (including transaction costs). This stock repurchase is recorded in *treasury stock* on our Consolidated Balance Sheet. Our Consolidated Statement of Cash Flows reflects $93 million of treasury stock purchases in first-quarter 2008 due to approximately $33 million of purchases made in late March 2008 that were not settled until April 2008.

At December 31, 2007, we held all of Williams Partners L.P. s seven million subordinated units outstanding. In February 2008, these subordinated units were converted into common units of Williams Partners L.P. due to the achievement of certain financial targets which resulted in the early termination of the subordination period. While these subordinated units were outstanding, other issuances of partnership units by Williams Partners L.P. had preferential rights and the proceeds from these issuances in excess of the book basis of assets acquired by Williams Partners L.P. were therefore reflected as minority interest on our Consolidated Balance Sheet rather than as equity. Due to the conversion of the subordinated units, these original issuances of partnership units no longer have preferential rights and now represent the lowest level of equity securities issued by Williams Partners L.P. In accordance with our policy regarding the issuance of equity of a consolidated subsidiary, such issuances of nonpreferential equity are accounted for as capital transactions and no gain or loss is recognized. Therefore, as a result of the first-quarter conversion, we recognized a decrease to minority interest and a corresponding increase to stockholders equity of approximately $1.2 billion.

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Note 12. Contingent Liabilities

Rate and Regulatory Matters and Related Litigation

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result, a portion of the revenues of these subsidiaries has been collected subject to refund. We have accrued a liability for these potential refunds as of March 31, 2008, which we believe is adequate for any refunds that may be required.

We are party to pending matters involving pipeline transportation rates charged to our former Alaska refinery in prior periods. In February 2008, the Alaska Supreme Court ruled in our favor in one of these cases and we subsequently received a payment of $74 million in March 2008. Considering the relevant facts and circumstances related to this matter, including the first-quarter 2008 favorable Alaska Supreme Court ruling, our assessment of the counterparties limited remaining options, and the payment received in first-quarter 2008, we believe that the likelihood of successful appeal by the counterparties is remote. As a result, during first-quarter 2008 we recognized the $74 million as pre-tax income.

Issues Resulting from California Energy Crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the Federal Energy Regulatory Commission (FERC). These challenges included refund proceedings, summer 2002 90-day contracts, investigations of alleged market manipulation including withholding, gas indices and other gaming of the market, new long-term power sales to the State of California that were subsequently challenged and civil litigation relating to certain of these issues. We have entered into settlements with the State of California (State Settlement), major California utilities (Utilities Settlement), and others that substantially resolved each of these issues with these parties.

As a result of a 2006 Ninth Circuit Court of Appeals decision, which the U.S. Supreme Court has agreed to review, certain contracts that we entered into during 2000 and 2001 may be subject to partial refunds. These contracts, under which we sold electricity, totaled approximately $89 million in revenue. We expect the U.S. Supreme Court s decision in 2008. While we are not a party to the cases involved in the appellate court decision under review, the buyer of electricity from us is a party to the cases and claims that we must refund to the buyer any loss it suffers due to the decision and the FERC s reconsideration of the contract terms at issue in the decision.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Refund proceedings

Although we entered into the State Settlement and Utilities Settlement, which resolved the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, such as various California end users that did not participate in the Utilities Settlement. As a part of the Utilities Settlement, we funded escrow accounts that we anticipate will satisfy any ultimate refund determinations in favor of the nonsettling parties including interest on refund amounts that we might owe to settling and nonsettling parties. We are also owed interest from counterparties in the California market during the refund period for which we have recorded a receivable totaling approximately $24 million at March 31, 2008. Collection of the interest and the payment of interest on refund amounts from the escrow accounts is subject to the conclusion of this proceeding. Therefore, we continue to participate in the FERC refund case and related proceedings.

Challenges to virtually every aspect of the refund proceedings, including the refund period, were and continue to be made to the Ninth Circuit Court of Appeals and the U.S. Supreme Court. In 2006, the Ninth Circuit issued its order that largely upheld the FERC s prior rulings, but it expanded the types of transactions that were made subject to refund. This order is subject to further appeal. Because of our settlements, we do not expect that the 2006 decision will have a material impact on us. However, the final refund calculation has not been made because of the appeals and certain unclear aspects of the refund calculation process.

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Notes (Continued)

Reporting of Natural Gas-Related Information to Trade Publications

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, in each case seeking an unspecified amount of damages. We are currently a defendant in:

State court litigation in California brought on behalf of certain business and governmental entities that purchased gas for their use.

Class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri, Tennessee and Wisconsin brought on behalf of direct and indirect purchasers of gas in those states. The Tennessee purchasers have appealed the Tennessee state court s 2007 dismissal of their case. The Missouri case has been remanded to Missouri state court. The cases in the other jurisdictions have been removed and transferred to the federal court in Nevada. On February 19, 2008, the federal court granted summary judgment in the Colorado case in favor of us and most of the other defendants. We expect that the Colorado plaintiffs will appeal.

Mobile Bay Expansion

In 2002, an administrative law judge at the FERC issued an initial decision in Transcontinental Gas Pipe Line Corporation s (Transco) 2001 general rate case which, among other things, rejected the recovery of the costs of Transco s Mobile Bay expansion project from its shippers on a rolled-in basis and found that incremental pricing for the Mobile Bay expansion project is just and reasonable. In 2004, the FERC issued an Order on Initial Decision in which it reversed certain parts of the administrative law judge s decision and accepted Transco s proposal for rolled-in rates. Gas Marketing Services holds long-term transportation capacity on the Mobile Bay expansion project. Certain parties filed appeals in federal court seeking to overturn the FERC s ruling on the rolled-in rates. On April 2, 2008, Gas Marketing Services executed an agreement that settled this matter for $10 million, which was accrued in 2007.

Environmental Matters

Continuing operations

Since 1989, our Transco subsidiary has had studies underway to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests from the U.S. Environmental Protection Agency (EPA) and state agencies regarding such potential contamination of certain of its sites. Transco has identified polychlorinated biphenyl (PCB) contamination in compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other parties concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. The costs of any such remediation will depend upon the scope of the remediation. At March 31, 2008, we had accrued liabilities of $5 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances. Transco has been identified as a potentially responsible party at various Superfund and state waste disposal sites. Based on present volumetric estimates and other factors, we have estimated our aggregate exposure for remediation of these sites to be less than $500,000, which is included in the environmental accrual discussed above. We expect that these costs will be recoverable through Transco s rates.

Beginning in the mid-1980s, our Northwest Pipeline subsidiary evaluated many of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation might be necessary. Consistent with other natural gas transmission companies, Northwest Pipeline identified PCB contamination in air compressor systems, soils and related properties at certain compressor station sites. Similarly, Northwest Pipeline identified hydrocarbon impacts at these facilities due to the former use of earthen pits and mercury contamination at certain gas metering sites. The PCBs were remediated pursuant to a Consent Decree with the EPA in the late 1980s and Northwest Pipeline conducted a voluntary clean-up of the hydrocarbon and mercury impacts in the early 1990s. In 2005, the Washington Department of Ecology required Northwest Pipeline to reevaluate its previous mercury clean-ups in Washington. Consequently, Northwest Pipeline is conducting additional remediation activities at certain sites to comply with Washington s current environmental standards. At March 31, 2008, we have accrued liabilities

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totaling approximately $7 million for these costs. We expect that these costs will be recoverable through Northwest Pipeline s rates.

In March 2008, the EPA issued a new air quality standard for ground level ozone. We currently do not know if our interstate gas pipelines will be impacted. If they are, we will likely incur additional capital expenditures to comply. At this time we are unable to estimate the cost of these additions that may be required to meet the new regulations. We expect that costs associated with these compliance efforts will be recoverable through rates.

We also accrue environmental remediation costs for natural gas underground storage facilities, primarily related to soil and groundwater contamination. At March 31, 2008, we have accrued liabilities totaling approximately $5 million for these costs.

In July 2006, the Colorado Department of Public Health and Environment (CDPHE) issued a Notice of Violation (NOV) to Williams Production RMT Company related to operating permits for our Roan Cliffs and Hayburn gas plants in Garfield County, Colorado. In February 2008, the CDPHE combined this matter and the June 2007 audit disclosure matter discussed below.

Williams Production RMT Company performed voluntary audits of its 2006 and 2007 compliance with state and federal air regulations. In June 2007, we disclosed to the CDPHE, pursuant to the Colorado audit immunity privilege, that our facilities were not in compliance. We also described corrective actions that had or would be taken to remedy the issues. On February 22, 2008, we received a draft order from the CDPHE that identifies (1) several violations that we previously self-disclosed to the agency as well as pending NOVs from 2006 for the Hayburn and Roan Cliffs gas plants and (2) findings from agency inspections at various facilities in Parachute, Colorado. The CDPHE denied our request for penalty immunity for self-disclosing these violations and proposed a $650,000 penalty. We dispute the denial and the proposed penalty and will meet with the CDPHE to attempt an informal resolution of these issues without further proceedings.

In April 2007, the New Mexico Environment Department s Air Quality Bureau (NMED) issued an NOV to Williams Four Corners, LLC (Four Corners) that alleged various emission and reporting violations in connection with our Lybrook gas processing plant s flare and leak detection and repair program. The NMED proposed a penalty of approximately $3 million. We are discussing the basis for and the scope of the proposed penalty with the NMED.

In April 2007, the CDPHE issued an NOV to Williams Production RMT Company related to alleged air permit violations at the Rifle Station natural gas dehydration facility located in Garfield County, Colorado. The Rifle Station facility had been shut down prior to our receipt of the NOV and, except for some minor operations, remains closed. We responded to the CDPHE s notice in May 2007.

In April 2007, the Wyoming Department of Environmental Quality (WDEQ) issued an NOV to Williams Production RMT Company that alleged violations of various Wyoming Pollution Discharge Elimination System permits for our coal bed methane gas production facilities in the state. In March 2008, we settled the matter by agreeing to pay a penalty of $48,000, a portion of which may be used instead for a supplemental environmental project.

In March 2008, the EPA proposed a penalty of $370,000 for alleged violations relating to leak detection and repair program delays at our Ignacio gas plant and for alleged permit violations at a compressor station. We met with the EPA and are exchanging information in order to resolve the issues.

In September 2007, the EPA requested, and our Transco subsidiary later provided, information regarding natural gas compressor stations in the states of Mississippi and Alabama as part of the EPA s investigation of our compliance with the Clean Air Act. On March 28, 2008, the EPA issued NOVs alleging violations of Clear Air Act requirements at these compressor stations and offered to discuss the NOVs at a conference in May 2008.

Former operations, including operations classified as discontinued

In connection with the sale of certain assets and businesses, we have retained responsibility, through indemnification of the purchasers, for environmental and other liabilities existing at the time the sale was consummated, as described below.

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Notes (Continued)

Agrico

In connection with the 1987 sale of the assets of Agrico Chemical Company, we agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations to the extent such costs exceed a specified amount. At March 31, 2008, we have accrued liabilities of approximately $9 million for such excess costs.

Other

At March 31, 2008, we have accrued environmental liabilities totaling approximately $17 million related primarily to our:

Potential indemnification obligations to purchasers of our former retail petroleum and refining operations;

Former propane marketing operations, bio-energy facilities, petroleum products and natural gas pipelines;

Discontinued petroleum refining facilities;

Former exploration and production and mining operations.

Certain of our subsidiaries have been identified as potentially responsible parties at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws.

Summary of environmental matters

Actual costs incurred for these matters could be substantially greater than amounts accrued depending on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors, but the amount cannot be reasonably estimated at this time.

Other Legal Matters

Will Price (formerly Quinque)

In 2001, fourteen of our entities were named as defendants in a nationwide class action lawsuit in Kansas state court that had been pending against other defendants, generally pipeline and gathering companies, since 2000. The plaintiffs alleged that the defendants have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs and sought an unspecified amount of damages. The fourth amended petition, which was filed in 2003, deleted all of our defendant entities except two Midstream subsidiaries. All remaining defendants have opposed class certification and a hearing on plaintiffs second motion to certify the class was held in April 2005. We are awaiting a decision from the court. The amount of any possible liability cannot be reasonably estimated at this time.

Grynberg

In 1998, the DOJ informed us that Jack Grynberg, an individual, had filed claims on behalf of himself and the federal government, in the United States District Court for the District of Colorado under the False Claims Act against us and certain of our wholly owned subsidiaries. The claims sought an unspecified amount of royalties allegedly not paid to the federal government, treble damages, a civil penalty, attorneys fees, and costs. In connection with our sales of Kern River Gas Transmission in 2002 and Texas Gas Transmission Corporation in 2003, we agreed to indemnify the purchasers for any liability relating to this claim, including legal fees. The maximum amount of future payments that we could potentially be required to pay under these indemnifications depends upon the ultimate resolution of the claim and cannot currently be determined. Grynberg had also filed claims against approximately 300 other energy companies alleging that the defendants violated the False Claims Act in connection with the measurement, royalty valuation and purchase of hydrocarbons. In 1999, the DOJ announced

Notes (Continued)
that it would not intervene in any of the Grynberg cases. Also in 1999, the Panel on Multi-District Litigation transferred all of these cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. Grynberg s measurement claims remained pending against us and the other defendants; the court previously dismissed Grynberg s royalty valuation claims. In 2005, the court-appointed special master entered a report which recommended that the claims against our Gas Pipeline and Midstream subsidiaries be dismissed but upheld the claims against our Exploration & Production subsidiaries against our jurisdictional challenge. In October 2006, the District Court dismissed all claims against us and our wholly owned subsidiaries, and in November 2006, Grynberg filed his notice of appeal with the Tenth Circuit Court of Appeals.

In August 2002, Jack J. Grynberg, and Celeste C. Grynberg, Trustee on Behalf of the Rachel Susan Grynberg Trust, and the Stephen Mark Grynberg Trust, served us and one of our Exploration & Production subsidiaries with a complaint in the state court in Denver, Colorado. The complaint alleges that we have used mismeasurement techniques that distort the British Thermal Unit heating content of natural gas, resulting in the alleged underpayment of royalties to Grynberg and other independent natural gas producers. The complaint also alleges that we inappropriately took deductions from the gross value of their natural gas and made other royalty valuation errors. Under various theories of relief, the plaintiff is seeking actual damages of between $2 million and $20 million based on interest rate variations and punitive damages in the amount of approximately $1 million. In 2004, Grynberg filed an amended complaint against one of our Exploration & Production subsidiaries. This subsidiary filed an answer in 2005, denying liability for the damages claimed. Trial in this case has been set for September 2008. The amount of any possible liability cannot be reasonably estimated at this time.

Securities class actions

Numerous shareholder class action suits were filed against us in 2002 in the United States District Court for the Northern District of Oklahoma. The majority of the suits alleged that we and co-defendants, WilTel, previously an owned subsidiary known as Williams Communications, and certain corporate officers, acted jointly and separately to inflate the stock price of both companies. WilTel was dismissed as a defendant as a result of its bankruptcy. These cases were consolidated and an order was issued requiring separate amended consolidated complaints by our equity holders and WilTel equity holders. The underwriter defendants have requested indemnification and defense from these cases. If we grant the requested indemnifications to the underwriters, any related settlement costs will not be covered by our insurance policies. We covered the cost of defending the underwriters. In 2002, the amended complaints of the WilTel securities holders and of our securities holders added numerous claims. On February 9, 2007, the court gave its final approval to our settlement with our securities holders. We entered into indemnity agreements with certain of our insurers to ensure their timely payment related to this settlement. The carrying value of our estimated liability related to these agreements is immaterial because we believe the likelihood of any future performance is remote.

On July 6, 2007, the court granted various defendants motions for summary judgment and entered judgment for us and the other defendants in the WilTel matter. The plaintiffs appealed the court s judgment. Any obligation of ours to the WilTel equity holders as a result of a settlement, or as a result of trial in the event of a successful appeal of the court s judgment, will not likely be covered by insurance because our insurance coverage has been fully utilized by the settlement described above. The extent of any such obligation is presently unknown and cannot be estimated, but it is reasonably possible that our exposure could materially exceed amounts accrued for this matter.

TAPS Quality Bank

One of our subsidiaries, Williams Alaska Petroleum, Inc. (WAPI), is actively engaged in administrative litigation being conducted jointly by the FERC and the Regulatory Commission of Alaska (RCA) concerning the Trans-Alaska Pipeline System (TAPS) Quality Bank. In 2004, the FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions, and we accrued approximately $134 million based on our computation and assessment of ultimate ruling terms that were considered probable. Our additional potential refund liability terminated on March 31, 2004, when we sold WAPI s interests in the TAPS pipeline. We subsequently accrued additional amounts for interest.

In 2006, the FERC entered its final order, which the RCA adopted. On February 15, 2008, the Alaska Supreme Court upheld the RCA s order and on March 16, 2008, the D.C. Circuit Court of Appeals

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upheld the FERC s order. Through March 2008, we have paid substantially all amounts invoiced by the Quality Bank Administrator and third parties, except certain disputed amounts which remain accrued. Certain counterparties might file further appeals with the U.S. Supreme Court.

We believe that the likelihood of successful appeal by the counterparties is remote, considering the relevant facts and circumstances related to this matter, including the favorable 2008 Alaska Supreme Court and D.C. Circuit Court of Appeals rulings, and our assessment of the counterparties limited remaining options. As a result, during the first quarter of 2008 we reduced remaining amounts accrued in excess of our estimated remaining obligation by $54 million.

Redondo Beach taxes

In February 2005, we and AES Redondo Beach, L.L.C. received a tax assessment letter from the city of Redondo Beach, California, in which the city asserted that approximately $33 million in back taxes and approximately $39 million in interest and penalties are owed related to natural gas used at the generating facility operated by AES Redondo Beach. Hearings were held in July 2005 and in September 2005 the tax administrator for the city issued a decision in which he found us jointly and severally liable with AES Redondo Beach for back taxes of approximately $36 million and interest and penalties of approximately $21 million. Both we and AES Redondo Beach filed notices of appeal that were heard at the city level. In December 2006, the city hearing officer for the appeal of the pre-2005 amounts issued a final decision affirming our utility user tax liability and reversing AES Redondo Beach s liability because the officer ruled that AES Redondo Beach is an exempt public utility. We appealed this decision to the Los Angeles Superior Court, and the city also appealed with respect to AES Redondo Beach. In April 2007, we paid the city the protested amount of approximately $57 million in order to pursue our appeal. On March 14, 2008, the Los Angeles Superior Court decided in our favor, finding, among other things, that the challenged assessment was not supported by the city s utility users tax ordinance and was issued in violation of the California State Constitution. On April 2, 2008, the city filed a notice of appeal of the decision. We and AES Redondo Beach also filed separate refund actions in Los Angeles Superior Court related to certain taxes paid since the initial 2005 notice of assessment. The refund actions are stayed pending the resolution of the appeals.

The city s most recent assessment of our liability for the periods from 1998 through September 2007 is approximately $72 million (inclusive of interest and penalties). In connection with the sale of our power business (see Note 2), we settled our dispute with AES Redondo Beach by equally sharing, for periods prior to the closing of the sale, any ultimate tax liability as well as the funding of amounts previously paid under protest. We continue to believe that a contingent loss in this matter is not probable.

Gulf Liquids litigation

Gulf Liquids contracted with Gulsby Engineering Inc. (Gulsby) and Gulsby-Bay for the construction of certain gas processing plants in Louisiana. National American Insurance Company (NAICO) and American Home Assurance Company provided payment and performance bonds for the projects. In 2001, the contractors, and sureties filed multiple cases in Louisiana and Texas against Gulf Liquids and us.

In 2006, at the conclusion of the consolidated trial of the asserted contract and tort claims, the jury returned its actual and punitive damages verdict against us and Gulf Liquids. Based on our interpretation of the jury verdicts, we estimated exposure for actual damages of approximately $68 million plus potential interest of approximately $25 million, all of which have been accrued as of March 31, 2008. In addition, we concluded that it was reasonably possible that any ultimate judgment might have included additional amounts of approximately $199 million in excess of our accrual, which primarily represented our estimate of potential punitive damage exposure under Texas law.

From May through October 2007, the court entered seven post-trial orders in the case (interlocutory orders) which, among other things, overruled the verdict award of tort and punitive damages as well as any damages against us. The court also denied the plaintiffs claims for attorneys fees. On January 28, 2008, the court issued its judgment awarding damages against Gulf Liquids of approximately $11 million in favor of Gulsby and approximately $4 million in favor of Gulsby-Bay. If the judgment is upheld on appeal, our liability will be substantially less than the amount of our accrual for these matters.

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Wyoming severance taxes

In August 2006, the Wyoming Department of Audit (DOA) assessed our subsidiary Williams Production RMT Company for additional severance tax and interest for the production years 2000 through 2002. In addition, the DOA notified us of an increase in the taxable value of our interests for ad valorem tax purposes. We disputed the DOA s interpretation of the statutory obligation and appealed this assessment to the Wyoming State Board of Equalization (SBOE). The SBOE upheld the assessment and remanded it to the DOA to address the disallowance of a credit. The SBOE did not award interest on the assessment. We estimate that the amount of the additional severance and ad valorem taxes to be approximately $4 million. The Wyoming Supreme Court has agreed to hear our appeal of the SBOE s determination. If the DOA prevails in its interpretation of our obligation and applies the same basis of assessment to subsequent periods, it is reasonably possible that we could owe a total of approximately $19 million to $22 million in additional taxes and interest from January 1, 2003 through March 31, 2008.

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in Colorado state court alleging that we improperly calculated oil and gas royalty payments, failed to account for the proceeds that we received from the sale of gas and extracted products, improperly charged certain expenses, and failed to refund amounts withheld in excess of ad valorem tax obligations. The plaintiffs claim that the class might be in excess of 500 individuals and seek an accounting and damages. The parties have agreed to stay this action in order to participate in ongoing mediation.

Certain other royalty matters are currently being litigated by a federal regulatory agency and another Colorado producer. Although we are not a party to the litigation, the final outcome of that case might lead to a future unfavorable impact on our results of operations.

Other Divestiture Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

We sold a natural gas liquids pipeline system in 2002, and in 2006, the purchaser of that system filed its complaint against us and our subsidiaries in state court in Houston, Texas. The purchaser alleges that we breached certain warranties under the purchase and sale agreement and seeks approximately $18 million in damages and our specific performance under certain guarantees. The trial is scheduled to begin on September 15, 2008, and our prior suit filed against the purchaser in Delaware state court is stayed pending resolution of the Texas case.

At March 31, 2008, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against us which are incidental to our operations.

Summary

Litigation, arbitration, regulatory matters, and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the results of operations in the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance

Notes (Continued)
coverage, recovery from customers or other indemnification arrangements, will not have a materially adverse effect upon our future financial position.

Guarantees

In connection with agreements executed prior to our acquisition of Transco to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco entered into certain settlements with producers which may require the indemnification of certain claims for additional royalties that the producers may be required to pay as a result of such settlements. Transco, through its agent, Gas Marketing Services, continues to purchase gas under contracts which extend, in some cases, through the life of the associated gas reserves. Certain of these contracts contain royalty indemnification provisions that have no carrying value. Producers have received certain demands and may receive other demands, which could result in claims pursuant to royalty indemnification provisions. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the agreement between the producer and Transco. Consequently, the potential maximum future payments under such indemnification provisions cannot be determined. However, management believes that the probability of material payments is remote.

In connection with the 1993 public offering of units in the Williams Coal Seam Gas Royalty Trust (Royalty Trust), our Exploration & Production segment entered into a gas purchase contract for the purchase of natural gas in which the Royalty Trust holds a net profits interest. Under this agreement, we guarantee a minimum purchase price that the Royalty Trust will realize in the calculation of its net profits interest. We have an annual option to discontinue this minimum purchase price guarantee and pay solely based on an index price. The maximum potential future exposure associated with this guarantee is not determinable because it is dependent upon natural gas prices and production volumes. No amounts have been accrued for this contingent obligation as the index price continues to substantially exceed the minimum purchase price.

We are required by certain foreign lenders to ensure that the interest rates received by them under various loan agreements are not reduced by taxes by providing for the reimbursement of any domestic taxes required to be paid by the foreign lender. The maximum potential amount of future payments under these indemnifications is based on the related borrowings. These indemnifications generally continue indefinitely unless limited by the underlying tax regulations and have no carrying value. We have never been called upon to perform under these indemnifications.

We have provided guarantees in the event of nonpayment by our previously owned communications subsidiary, WilTel, on certain lease performance obligations that extend through 2042. The maximum potential exposure is approximately $43 million at March 31, 2008. Our exposure declines systematically throughout the remaining term of WilTel s obligations. The carrying value of these guarantees is approximately $39 million at March 31, 2008.

Former managing directors of Gulf Liquids are involved in litigation related to the construction of gas processing plants. Gulf Liquids has indemnity obligations to the former managing directors for legal fees and potential losses that may result from this litigation. Claims against these former managing directors have been settled and dismissed after payments on their behalf by directors and officers insurers. Some unresolved issues remain between us and these insurers, but no amounts have been accrued for any potential liability.

We have guaranteed the performance of a former subsidiary of our wholly owned subsidiary MAPCO Inc., under a coal supply contract. This guarantee was granted by MAPCO Inc. upon the sale of its former subsidiary to a third party in 1996. The guaranteed contract provides for an annual supply of a minimum of 2.25 million tons of coal. Our potential exposure is dependent on the difference between current market prices of coal and the pricing terms of the contract, both of which are variable, and the remaining term of the contract. Given the variability of the terms, the maximum future potential payments cannot be determined. We believe that our likelihood of performance under this guarantee is remote. In the event we are required to perform, we are fully indemnified by the purchaser of MAPCO Inc. s former subsidiary. This guarantee expires in December 2010 and has no carrying value.

We have guaranteed commercial letters of credit totaling $20 million on behalf of ACCROVEN, an equity method investee. These expire in January 2009 and have no carrying value.

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We have provided guarantees on behalf of certain entities in which we have an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. There are no expiration dates associated with these guarantees. No amounts have been accrued at March 31, 2008.

Note 13. Comprehensive Income

Comprehensive income is as follows:

	Three months ended March 31,	
	2008	2007
	(Millions)	
Net income	$ 500	$ 134
Other comprehensive income (loss):		
Net unrealized gains (losses) on derivative instruments	(217)	10
Net reclassification into earnings of derivative instrument losses	20	10
Foreign currency translation adjustments	(21)	3
Pension benefits:		
Amortization of net actuarial loss	2	4
Other comprehensive income (loss) before taxes	(216)	27
Income tax benefit (provision) on other comprehensive income	75	(9)
Other comprehensive income (loss)	(141)	18
Comprehensive income	$ 359	$ 152

Net unrealized gains (losses) on derivative instruments represents changes in the fair value of certain derivative contracts that have been designated as cash flow hedges. The net unrealized losses at March 31, 2008, primarily include net unrealized losses on forward natural gas purchases and sales of $214 million. The net unrealized gains at March 31, 2007, include net unrealized gains on forward natural gas purchases and sales of $33 million, partially offset by net unrealized losses on forward power purchases and sales of $23 million.

Note 14. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge. Our master limited partnerships, Williams Partners L.P. and Williams Pipeline Partners L.P., are consolidated within our Midstream and Gas Pipeline segments, respectively. (See Note 2.) Other primarily consists of corporate operations.

Performance Measurement

We currently evaluate performance based upon *segment profit (loss)* from operations, which includes *segment revenues* from external and internal customers, *segment costs and expenses*, *depreciation, depletion and amortization*, *equity earnings (losses)* and *income (loss) from investments* including impairments related to investments accounted for under the equity method. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

Energy commodity hedging by our business units may be done through intercompany derivatives with our Gas Marketing Services segment which, in turn, enters into offsetting derivative contracts with unrelated third parties. Gas Marketing Services bears the counterparty performance risks associated with the unrelated third parties in these transactions. Additionally, beginning in the first quarter of 2007, hedges related to Exploration & Production may be entered into directly between Exploration & Production and third parties under its credit agreement. Exploration & Production bears the counterparty performance risks associated with the unrelated third parties in these transactions.

External revenues of our Exploration & Production segment include third-party oil and gas sales, which are more than offset by transportation expenses and royalties due third parties on intersegment sales.

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Notes (Continued)

The following table reflects the reconciliation of *segment revenues* and *segment profit (loss)* to *revenues* and *operating income (loss)* as reported in the Consolidated Statement of Income.

	Exploration & Production	Gas Pipeline	Midstream Gas & Liquids	Gas Marketing Services (Millions)	Other	Eliminations	Total
Three months ended March 31, 2008							
Segment revenues:							
External	$ (46)	$ 402	$ 1,544	$ 1,320	$ 4	$	$ 3,224
Internal	794	11	13	330	2	(1,150)	
Total revenues	$ 748	$ 413	$ 1,557	$ 1,650	$ 6	$ (1,150)	$ 3,224
Segment profit	$ 430	$ 180	$ 261	$ 21	$ 1	$	$ 893
Less equity earnings	3	10	23				36
Segment operating income	$ 427	$ 170	$ 238	$ 21	$ 1	$	857
General corporate expenses							(42)
Total operating income							$ 815
Three months ended March 31, 2007							
Segment revenues:							
External	$ (62)	$ 363	$ 991	$ 1,074	$ 2	$	$ 2,368
Internal	545	8	11	214	5	(783)	
Total revenues	$ 483	$ 371	$ 1,002	$ 1,288	$ 7	$ (783)	$ 2,368
Segment profit (loss)	$ 188	$ 150	$ 154	$ (30)	$	$	$ 462
Less equity earnings	5	9	7				21
Segment operating income (loss)	$ 183	$ 141	$ 147	$ (30)	$	$	441
General corporate expenses							(40)
Total operating income							$ 401

The following table reflects *total assets* by reporting segment.

Total Assets

	March 31, 2008	December 31, 2007
	(Millions)	
Exploration & Production	$ 9,516	$ 8,692
Gas Pipeline	9,043	8,624
Midstream Gas & Liquids	6,884	6,604
Gas Marketing Services (1)	6,320	4,437
Other	3,908	3,592
Eliminations (2)	(8,560)	(7,073)
	27,111	24,876
Assets of discontinued operations	61	185
Total assets	$ 27,172	$ 25,061

(1) The increase in Gas Marketing Services total assets is due primarily to an increase in derivative assets as a result of the impact of changes in commodity prices on existing forward derivative contracts. Gas Marketing Services derivative assets are substantially offset by their derivative liabilities.

(2) The increase in Eliminations is due primarily to an increase in the intercompany derivative balances.

Note 15. Recent Accounting Standards

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157). This Statement establishes a framework for fair value measurements in the financial statements by providing a definition of fair value, provides guidance on the methods used to estimate fair value and expands disclosures about fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007. In February 2008, the FASB issued FASB Staff Position (FSP) No. FAS 157-2, permitting entities to delay application of SFAS 157 to fiscal years beginning after November 15, 2008, for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). On

Notes (Continued)

January 1, 2008, we applied SFAS 157 to our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. See Note 10 for discussion of the adoption. Beginning January 1, 2009, we will apply SFAS 157 fair value requirements to nonfinancial assets and nonfinancial liabilities that are not recognized or disclosed on a recurring basis. Application will be prospective when nonrecurring fair value measurements are required. We will assess the impact on our Consolidated Financial Statements of applying these requirements to nonrecurring fair value measurements for nonfinancial assets and nonfinancial liabilities.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51 (SFAS 160). SFAS 160 establishes accounting and reporting standards for noncontrolling ownership interests in subsidiaries (previously referred to as minority interests). Noncontrolling ownership interests in consolidated subsidiaries will be presented in the consolidated balance sheet within stockholders equity as a separate component from the parent s equity. Consolidated net income will now include earnings attributable to both the parent and the noncontrolling interests. Earnings per share will continue to be based on earnings attributable to only the parent company and does not change upon adoption of SFAS 160. SFAS 160 provides guidance on accounting for changes in the parent s ownership interest in a subsidiary, including transactions where control is retained and where control is relinquished. SFAS 160 also requires additional disclosure of information related to amounts attributable to the parent for income from continuing operations, discontinued operations and extraordinary items and reconciliations of the parent and noncontrolling interests equity of a subsidiary. SFAS 160 is effective for fiscal years beginning after December 15, 2008, and early adoption is prohibited. The Statement will be applied prospectively to transactions involving noncontrolling interests, including noncontrolling interests that arose prior to the effective date, as of the beginning of the fiscal year it is initially adopted. However, the presentation of noncontrolling interests within stockholders equity and the inclusion of earnings attributable to the noncontrolling interests in consolidated net income requires retrospective application to all periods presented. We will assess the impact on our Consolidated Financial Statements.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS 161). SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, currently establishes the disclosure requirements for derivative instruments and hedging activities. SFAS 161 amends and expands the disclosure requirements of Statement 133 with enhanced quantitative, qualitative and credit risk disclosures. The Statement requires quantitative disclosure in a tabular format about the fair values of derivative instruments, gains and losses on derivative instruments and information about where these items are reported in the financial statements. Also required in the tabular presentation is a separation of hedging and nonhedging activities. Qualitative disclosures include outlining objectives and strategies for using derivative instruments in terms of underlying risk exposures, use of derivatives for risk management and other purposes and accounting designation, and an understanding of the volume and purpose of derivative activity. Credit risk disclosures provide information about credit risk related contingent features included in derivative agreements. SFAS 161 also amends SFAS No. 107, Disclosures about Fair Value of Financial Instruments, to clarify that disclosures about concentrations of credit risk should include derivative instruments. This Statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. We plan to apply this Statement beginning in 2009. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. We will assess the application of this Statement on our disclosures in our Consolidated Financial Statements.

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Item 2
Management s Discussion and Analysis of
Financial Condition and Results of Operations

Company Outlook

Our plan for 2008 is focused on continued disciplined growth. Objectives of this plan include:

- Continue to improve both EVA® and segment profit;
- Invest in our businesses in a way that improves EVA®, meets customer needs, and enhances our competitive position:
  - Continue to increase natural gas production and reserves;
  - Increase the scale of our gathering and processing business in key growth basins;
  - Continue to invest in expansion projects on our interstate natural gas pipelines.

Potential risks and/or obstacles that could prevent us from achieving these objectives include:

- Volatility of commodity prices;
- Lower than expected levels of cash flow from operations;
- Decreased drilling success at Exploration & Production;
- Decreased drilling success by third parties served by Midstream and Gas Pipeline;
- Exposure associated with our efforts to resolve regulatory and litigation issues (see Note 12 of Notes to Consolidated Financial Statements);
- General economic, financial markets, or industry downturn;
- Changes in the current political and regulatory environment.

We continue to address these risks through utilization of commodity hedging strategies, focused efforts to resolve regulatory issues and litigation claims, disciplined investment strategies, and maintaining our desired level of at least $1 billion in liquidity from cash and cash equivalents and unused revolving credit facilities.

Our *income from continuing operations* for the three months ended March 31, 2008, increased $246 million compared to the three months ended March 31, 2007. This increase is reflective of:

- Higher net realized average prices and continued strong natural gas production growth at Exploration & Production;
- A pre-tax gain of $118 million on the sale of a contractual right to a production payment on certain future international hydrocarbon production at Exploration & Production;
- Continued favorable commodity price margins at Midstream.

See additional discussion in Results of Operations.

Our *net cash provided by operating activities* for the three months ended March 31, 2008, increased $494 million compared to the three months ended March 31, 2007, primarily due to the increase in our operating results. See additional discussion in Management s Discussion and Analysis of Financial Condition.

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Management s Discussion and Analysis (Continued)

Recent Events

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments. We recognized a pre-tax gain of approximately $118 million in the first quarter of 2008 related to the initial cash received. Any additional cash received from escrow will be recognized as income when received. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering of 16.25 million common units at a price of $20 per unit. In February 2008, the underwriters exercised their right to purchase an additional 1.65 million common units at the same price. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP. Upon completion of these transactions, we now hold approximately 47.7 percent of the interests in Williams Pipeline Partners L.P., including the interests of the general partner which is wholly owned by us, and incentive distribution rights. In accordance with EITF Issue No. 04-5, Williams Pipeline Partners L.P. will continue to be consolidated within our Gas Pipeline segment due to our control through the general partner. (See Note 2 of Notes to Consolidated Financial Statements.)

On November 28, 2007, Transco filed a formal stipulation and agreement with the Federal Energy Regulatory Commission (FERC) resolving all substantive issues in Transco s pending 2006 rate case. On March 7, 2008, the FERC approved the agreement without modification. The agreement is effective June 1, 2008.

In first-quarter 2008, we recognized pre-tax income of approximately $128 million in *income (loss) from discontinued operations* related to our former Alaska operations. This amount includes $74 million related to cash received upon the favorable resolution of a matter involving pipeline transportation rates and $54 million related to a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank. (See Note 12 of Notes to Consolidated Financial Statements.)

In first-quarter 2008, we purchased approximately 4 million shares of our common stock for $126 million under our $1 billion common stock repurchase program at an average cost of $33.95 per share. (See Note 11 of Notes to Consolidated Financial Statements.)

General

Unless indicated otherwise, the following discussion and analysis of Results of Operations and Financial Condition relates to our current continuing operations and should be read in conjunction with the Consolidated Financial Statements and notes thereto included in Item 1 of this document and our 2007 Annual Report on Form 10-K.

Fair Value Measurements

On January 1, 2008 we adopted Statement of Financial Accounting Standards No. 157, Fair Value Measurements (SFAS 157), for our assets and liabilities that are measured at fair value on a recurring basis, primarily our energy derivatives. See Note 10 of Notes to Consolidated Financial Statements for disclosures regarding SFAS 157, including discussion of the fair value hierarchy levels and valuation methodologies.

Certain of our energy derivative assets and liabilities and other assets are valued using unobservable inputs and included in Level 3. At March 31, 2008, the fair value of the Level 3 assets represents approximately six percent of the total assets measured at fair value. The fair value of the Level 3 liabilities represents approximately ten percent of the total liabilities measured at fair value.

The instruments included in Level 3 at March 31, 2008, predominantly consist of options that primarily hedge future sales of production from our Exploration & Production segment, are structured as costless collars and are financially settled. The remaining options are physically settled relating to the sale of natural gas. The options are valued using an industry standard Black-Scholes option pricing model. Certain inputs into the model are generally observable, such as commodity prices and interest rates, whereas a significant input, implied volatility by location, is unobservable. The impact of volatility on changes in the overall fair value of the options structured as collars is reduced because of

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Management s Discussion and Analysis (Continued)
the offsetting nature of the put and call positions. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices. The hedges are accounted for as cash flow hedges where net unrealized gains and losses from changes in fair value are recorded in other comprehensive income and subsequently impact earnings when the underlying hedged production is sold. Exploration & Production has an unsecured credit agreement through February 2012 with certain banks which serves to reduce our usage of cash and other credit facilities for margin requirements related to Level 3 options included in the facility.

Results of Operations

Consolidated Overview

The following table and discussion is a summary of our consolidated results of operations for the three months ended March 31, 2008, compared to the three months ended March 31, 2007. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	Three months ended March 31, 2008	Three months ended March 31, 2007	$ Change from 2007*	% Change from 2007*
	(Millions)			
Revenues	$ 3,224	$ 2,368	+856	+36%
Costs and expenses:				
Costs and operating expenses	2,373	1,843	-530	-29%
Selling, general and administrative expenses	111	102	-9	-9%
Other income net	(117)	(18)	+99	NM
General corporate expenses	42	40	-2	-5%
Total costs and expenses	2,409	1,967		
Operating income	815	401		
Interest accrued net	(157)	(167)	+10	+6%
Investing income	55	52	+3	+6%
Minority interest in income of consolidated subsidiaries	(39)	(14)	-25	-179%
Other income net	5	2	+3	+150%
Income from continuing operations before income taxes	679	274		
Provision for income taxes	263	104	-159	-153%
Income from continuing operations	416	170		
Income (loss) from discontinued operations	84	(36)	+120	NM
Net income	$ 500	$ 134		

* + = Favorable change to *net income*; = Unfavorable change to *net*

income; NM = A percentage calculation is not meaningful due to change in signs, a zero-value denominator, or a percentage change greater than 200.

Three months ended March 31, 2008 vs. three months ended March 31, 2007

The increase in *revenues* is due primarily to higher natural gas liquids (NGLs) and olefins marketing revenues and higher olefins and NGLs production revenues at Midstream. Additionally, Exploration & Production revenues increased due to both increased net realized average prices and increased production volumes sold.

The increase in *costs and operating expenses* is largely due to increased NGLs and olefins marketing purchases and increased costs associated with our olefins production business at Midstream. Increased depreciation, depletion and amortization, and lease operating expenses at Exploration & Production also contributed to the higher costs.

Other income net within *operating income* in 2008 includes a gain of $118 million on the sale of a contractual right to a production payment on certain future international hydrocarbon production at Exploration & Production. (See Note 4 of Notes to Consolidated Financial Statements.) Also included are $10 million of net gains on foreign currency exchanges, primarily at Midstream.

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Management s Discussion and Analysis (Continued)

Other income net within *operating income* in 2007 includes income of $8 million due to the reversal of a planned major maintenance accrual at Midstream and $6 million of net gains on foreign currency exchanges, primarily at Midstream.

The increase in *operating income* reflects both increased net realized average prices and continued strong natural gas production growth at Exploration & Production and continued favorable commodity price margins at Midstream. In addition, it also reflects a gain of $118 million on the sale of a contractual right to a production payment at Exploration & Production, as previously discussed.

Interest accrued net decreased primarily due to lower interest rates on recent debt issuances. While our overall debt balances have been relatively comparable, the net effect of recent retirements and issuances has resulted in lower rates, including amounts refinanced under our $1.5 billion unsecured credit facility.

The increase in *investing income* is due primarily to a $16 million increase in equity earnings at Midstream, partially offset by a $14 million decrease in interest income largely due to lower average interest rates in the first quarter of 2008 compared to the first quarter of 2007.

Minority interest in income of consolidated subsidiaries increased primarily due to the growth in the minority interest holdings of Williams Partners L.P. and Williams Pipeline Partners L.P.

Provision for income taxes increased primarily due to higher pre-tax income. The effective tax rates for the three months ended March 31, 2008 and 2007, are greater than the federal statutory rates due primarily to the effect of state income taxes and taxes on foreign operations.

Income (loss) from discontinued operations in first-quarter 2008 primarily includes income recognized in connection with our former Alaska operations. (See Note 3 of Notes to Consolidated Financial Statements.) It includes the following pre-tax items:

$74 million of income related to cash received upon the favorable resolution of a matter involving pipeline transportation rates;

$54 million of income related to a reduction of remaining amounts accrued in excess of our obligation associated with the Trans-Alaska Pipeline System Quality Bank.

Income (loss) from discontinued operations in first-quarter 2007 primarily includes the operating results of substantially all of our former power business.

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Management s Discussion and Analysis (Continued)

Results of Operations Segments

Exploration & Production

Overview of Three Months Ended March 31, 2008

During the first three months of 2008, we continued our development drilling program in our growth basins. Accordingly, we:

- Benefited from increased domestic net realized average prices, which increased by approximately 24 percent compared to the first three months of 2007. The domestic net realized average price for the first three months of 2008 was $6.58 per thousand cubic feet of gas equivalent (Mcfe) compared to $5.32 per Mcfe in 2007. Net realized average prices include market prices, net of fuel and shrink and hedge positions, less gathering and transportation expenses.

- Increased average daily domestic production levels by approximately 20 percent compared to the first three months of 2007. The average daily domestic production for the first three months was approximately 1,013 million cubic feet of gas equivalent (MMcfe) in 2008 compared to 845 MMcfe in 2007. The increased production is primarily due to increased development within the Piceance, Powder River, and Fort Worth basins.

- Increased capital expenditures for domestic drilling, development, and acquisition activity in the first three months of 2008 by approximately $46 million compared to 2007.

The benefits of higher net realized average prices and higher production volumes were partially offset by increased operating costs. The increase in operating costs was primarily due to increased production volumes and higher well service and industry costs. In addition, higher production volumes increased depletion, depreciation, and amortization expense.

Significant events

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments. We recognized a pre-tax gain of approximately $118 million in the first quarter of 2008 related to the initial cash received, which is reflected in *other income net* within *segment costs and expenses*. Any additional cash received from escrow will be recognized as income when received. As a result of the contract termination, we have no further interests associated with the crude oil concession, which is located in Peru. We had obtained these interests through our acquisition of Barrett Resources Corporation in 2001.

Outlook for the Remainder of 2008

Our expectations for the remainder of the year include:

- Maintaining our development drilling program in our key basins of Piceance, Powder River, San Juan, Fort Worth, and Arkoma through our remaining planned capital expenditures projected between $1.1 and $1.3 billion.

- Continuing to grow our average daily domestic production level with a goal of 10 to 15 percent growth compared to 2007.

Approximately 70 MMcf per day of our forecasted 2008 daily production is hedged by NYMEX and basis fixed-price contracts at prices that average $3.99 per Mcf at a basin level. In addition, we have the following collar agreements for our remaining forecasted 2008 daily domestic production, shown at basin-level weighted-average prices and weighted-average volumes:

	Volume	Floor Price	Ceiling Price
	(MMcf/d)	($/Mcf)	

Remaining 2008 collar agreements:			
Rockies	160	$6.08	$ 9.04
San Juan	220	$6.37	$ 9.00
Mid-Continent	80	$7.02	$ 9.77

Management s Discussion and Analysis (Continued)

Risks to achieving our expectations include unfavorable natural gas market price movements which are impacted by numerous factors, including weather conditions and domestic natural gas production and consumption. Also, achievement of expectations can be affected by costs of services associated with drilling.

In addition, changes in laws and regulations may impact our development drilling program. The Colorado Oil & Gas Conservation Commission has recently published proposed rules that could increase our costs of permitting and environmental compliance, may affect our ability to meet our anticipated drilling schedule and therefore may have an unfavorable effect on our future results of operations.

Period-Over-Period Results

	Three months ended March 31,	
	2008	**2007**
	(Millions)	
Segment revenues	$ 748	$ 483
Segment profit	$ 430	$ 188

Three months ended March 31, 2008 vs. three months ended March 31, 2007

Total *segment revenues* increased $265 million, or 55 percent, primarily due to the following:

$203 million, or 49 percent, increase in domestic production revenues reflecting $116 million associated with a 24 percent increase in net realized average prices and $87 million associated with a 20 percent increase in average daily production volumes. The impact of hedge positions on increased net realized average prices includes the effect of less volumes hedged by fixed-price contracts that are lower than the current market prices (see additional discussion of hedging below). The increase in production volumes reflects an increase in the number of producing wells primarily from the Piceance, Powder River, and Fort Worth basins. Production revenues in 2008 and 2007 include approximately $17 million and $7 million, respectively, related to natural gas liquids and approximately $14 million and $6 million, respectively, related to condensate;

$49 million increase in revenues for gas management activities related to gas sold on behalf of certain outside parties which is offset by a similar increase in *segment costs and expenses*. This increase is primarily due to an increase in natural gas prices.

To manage the commodity price risk and volatility of owning producing gas properties, we enter into derivative forward sales contracts that fix the sales price relating to a portion of our future production. Approximately 7 percent of domestic production in the first quarter of 2008 was hedged by NYMEX and basis fixed-price contracts at a weighted-average price of $3.92 per Mcf at a basin level compared to 20 percent hedged at a weighted-average price of $3.94 per Mcf for the same period in 2007. Also, approximately 35 percent and 32 percent of first-quarter 2008 and first-quarter 2007 domestic production was hedged in the following collar agreements shown at basin-level weighted-average prices and weighted-average volumes:

	Volume	Floor Price	Ceiling Price
	(MMcf/d)	**($/Mcf)**	
1 st quarter 2008 collar agreements:			
Rockies	200	$6.33	$ 9.41
San Juan	147	$6.26	$ 8.78
Mid-Continent	10	$7.12	$ 8.67

1 st quarter 2007 collar agreements:			
NYMEX	15	$6.50	$ 8.25
Rockies	50	$5.65	$ 7.45
San Juan	130	$5.98	$ 9.63
Mid-Continent	75	$6.82	$ 10.80

Total *segment costs and expenses* increased $21 million, primarily due to the following:

$52 million higher depreciation, depletion and amortization expense primarily due to higher production volumes and increased capitalized drilling costs;

$49 million increase in expenses for gas management activities related to gas purchased on behalf of certain outside parties which is offset by a similar increase in *segment revenues*;

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Management s Discussion and Analysis (Continued)

$16 million higher lease operating expenses from the increased number of producing wells primarily within the Piceance, Powder River, and Fort Worth basins in combination with higher well and lease service expenses and facility expenses;

$15 million higher operating taxes primarily due to higher average market prices and higher production volumes sold;

Partially offsetting the increased costs is the $118 million gain associated with the previously discussed sale of our Peru interests in January 2008.

The $242 million increase in s*egment profit* is primarily due to the 24 percent increase in domestic net realized average prices, the 20 percent increase in average daily domestic production volumes, and the $118 million gain associated with the sale of our Peru interests, partially offset by the increases in *segment costs and expenses*.

Gas Pipeline

Overview of Three Months Ended March 31, 2008

Gas Pipeline master limited partnership

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering of 16.25 million common units at a price of $20 per unit. In February 2008, the underwriters exercised their right to purchase an additional 1.65 million common units at the same price. The initial asset of the partnership is a 35 percent interest in Northwest Pipeline GP. Upon completion of these transactions, we now hold approximately 47.7 percent of the interests in Williams Pipeline Partners L.P., including the interests of the general partner which is wholly owned by us, and incentive distribution rights. In accordance with EITF Issue No. 04-5, Williams Pipeline Partners L.P. will continue to be consolidated within our Gas Pipeline segment due to our control through the general partner. (See Note 2 of Notes to Consolidated Financial Statements.) Gas Pipeline s segment profit includes 100 percent of Williams Pipeline Partners L.P. s segment profit, with the minority interest s share deducted below segment profit.

Status of rate case

During 2006, Transco filed a general rate case with the FERC for increases in rates. The new rates were effective, subject to refund, on March 1, 2007. On November 28, 2007, Transco filed a formal stipulation and agreement with the FERC resolving all substantive issues in their pending 2006 rate case. On March 7, 2008, the FERC approved the agreement without modification. The agreement is effective June 1, 2008.

Outlook for the Remainder of 2008

Gulfstream expansion projects

In June 2007, our equity method investee, Gulfstream, received FERC approval to extend its existing pipeline approximately 34 miles within Florida. The extension will fully subscribe the remaining 345 Mdt/d of firm capacity on the existing pipeline. Construction began in January 2008 and it is expected to be placed into service in July 2008. Gulfstream s estimated cost of this project is approximately $125 million.

In September 2007, Gulfstream received FERC approval to construct 17.5 miles of 20-inch pipeline and to install a new compressor facility. Construction began in December 2007. The pipeline expansion will increase capacity by 155 Mdt/d and is expected to be placed into service in September 2008. The compressor facility is expected to be placed into service in January 2009. Gulfstream s estimated cost of this project is approximately $153 million.

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Management s Discussion and Analysis (Continued)

Sentinel expansion project

In December 2007, we filed an application with the FERC to construct an expansion in the northeast United States. The estimated cost of the project is approximately $169 million. The expansion will increase capacity by 142 Mdt/d and is expected to be placed into service in two phases, occurring in November 2008 and November 2009.

Period-Over-Period Results

	Three months ended March 31,	
	2008	**2007**
	(Millions)	
Segment revenues	$ 413	$ 371
Segment profit	$ 180	$ 150

Three months ended March 31, 2008 vs. three months ended March 31, 2007

Segment revenues increased $42 million, or 11 percent, due primarily to a $37 million increase in transportation revenue and a $5 million increase in storage revenue resulting primarily from Transco s new rates effective March 2007 compared to a full quarter of the new rates in the first quarter of 2008 and the Potomac and Leidy to Long Island expansion projects that Transco placed into service in fourth-quarter 2007. In addition, *segment revenues* increased $3 million due to exchange imbalance settlements (offset in *costs and operating expenses*).

Costs and operating expenses increased $6 million, or 3 percent, due primarily to an increase in costs of $3 million associated with exchange imbalance settlements (offset in *segment revenues*).

Selling, general and administrative (SG&A) expenses increased $1 million, or 2 percent, due primarily to the absence of a $5 million adjustment to correct rent expense in the first quarter of 2007, partially offset by a $2 million decrease in property insurance premiums on offshore facilities.

Other income net changed unfavorably by $6 million due primarily to $4 million in costs associated with project development included in the first quarter of 2008.

The $30 million, or 20 percent, increase in *segment profit* is driven by $42 million of higher *segment revenues*, primarily reflecting a full quarter of Transco s new transportation and storage rates in 2008 and new expansion projects placed into service in fourth-quarter 2007, partially offset by the unfavorable changes in *segment cost and expenses.*

Midstream Gas & Liquids

Overview of 2008

Midstream s ongoing strategy is to safely and reliably operate large-scale midstream infrastructure where our assets can be fully utilized and drive low per-unit costs. Our business is focused on consistently attracting new business by providing highly reliable service to our customers.

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Management s Discussion and Analysis (Continued)

Significant events during 2008 include the following:

Continued favorable commodity price margins

The average realized natural gas liquid (NGL) per unit margins at our processing plants during the first quarter of 2008 was 64 cents per gallon (cpg), down from a record 83 cpg in the fourth quarter of 2007. Strong NGL margins over the last year have significantly increased our rolling five-year average from approximately 18 cpg at the end of the first quarter of 2007 to 28 cpg at the end of the first quarter of 2008. Even so, NGL margins have exceeded our rolling five-year average for the last four quarters. The geographic diversification of Midstream assets contributed significantly to our realized unit margins resulting in margins generally greater than that of the industry benchmarks for gas processed in the Henry Hub area and fractionated and sold at Mont Belvieu. Rising prices for natural gas at our western United States gas processing plants were the major cause for the deterioration from record NGL per unit margins in the fourth quarter of 2007.

Expansion efforts in growth areas

Consistent with our strategy, we continued to expand our midstream operations where we have large-scale assets in growth basins.

We continue construction of 37-mile extensions of both of our oil and gas pipelines from our Devils Tower spar to the Blind Faith prospect located in Mississippi Canyon. These extensions, estimated to cost approximately $250 million, are expected to be ready for service by the second quarter of 2008.

We continue construction activities on the Perdido Norte project which will include an expansion of our Markham gas processing facility and oil and gas lines that will expand the scale of our existing infrastructure in the western deepwater of the Gulf of Mexico. The estimated cost is approximately $560 million. We began laying pipe in March 2008 and expect the project to be in service in the third quarter of 2009.

We began pre-construction activities on the new Willow Creek facility, a 450 MMcf/d natural gas processing plant in western Colorado s Piceance basin. Major equipment purchases, vessel fabrication, and site clearing and grading are well under way. We expect the new Willow Creek facility to recover 25,000 barrels per day of NGLs at startup, which is expected to be in the third quarter of 2009.

Management s Discussion and Analysis (Continued)

In addition, we continued the process of converting an existing natural gas pipeline acquired from Gas Pipeline in 2007 from natural gas to NGL service and constructing additional pipeline. The Parachute to Greasewood Express NGL pipeline will create a pipeline alternative for NGLs currently being transported by truck from Exploration & Production s existing Piceance basin processing plants to a major NGL transportation pipeline system. We expect this pipeline to be in service in the second quarter of 2008.

Williams Partners L.P.

We currently own approximately 23.6 percent of Williams Partners L.P., including the interests of the general partner, which is wholly owned by us, and incentive distribution rights. Considering the control of the general partner in accordance with EITF Issue No. 04-5, Williams Partners L.P. is consolidated within the Midstream segment. (See Note 2 of Notes to Consolidated Financial Statements.) Midstream s segment profit includes 100 percent of Williams Partners L.P. s segment profit, with the minority interest s share deducted below segment profit. The debt and equity issued by Williams Partners L.P. to third parties is reported as a component of our consolidated debt balance and minority interest balance, respectively.

Outlook for the Remainder of 2008

The following factors could impact our business in 2008.

As evidenced in recent years, natural gas and crude oil markets are highly volatile. NGL margins earned at our gas processing plants in the last four quarters were above our rolling five-year average, due to global economics maintaining high crude prices which correlate to strong NGL prices in relationship to natural gas prices. NGL products are the preferred feedstock for ethylene and propylene production, which are the building blocks of polyethylene or plastics, due to the relative price of alternative crude-based feedstocks. Although forecasted domestic demand for polyethylene has weakened, the global markets remain robust. These opportunities for global exports aided by the weak U.S. dollar currently support NGL margins continuing to exceed our rolling five-year average.

We have agreed to dedicate our equity NGL volumes from our two Wyoming plants, for transport under a long-term shipping agreement with Overland Pass Pipeline Company, LLC. We currently have a one percent interest in Overland Pass Pipeline Company, LLC and have the option to increase our ownership to 50 percent and become the operator within two years of the pipeline becoming operational. The terms of our current shipping arrangement will continue to be higher than the arrangements we utilized in 2007 until the Overland Pass pipeline is completed. Although we anticipate lower transportation costs when the Overland Pass pipeline is completed, we are currently in a dispute with Mid-America Pipeline Company, LLC regarding the dedication of NGL volumes from one of these Wyoming plants. An unfavorable outcome in this matter could result in higher future transportation costs for these volumes.

As part of our efforts to manage commodity price risks on an enterprise basis, during December 2007, and January and February 2008, we entered into various financial contracts. Approximately 28 percent of our forecasted annual domestic NGL sales for 2008 are hedged with collar agreements or fixed-price swap contracts. Approximately 24 percent of our forecasted domestic NGL sales have been hedged with collar agreements at a weighted average sales price range of 9 percent to 22 percent above our average 2007 domestic NGL sales price and approximately 4 percent of our forecasted domestic NGL sales have been hedged with fixed-price swap contracts. The natural gas shrink requirements associated with the sales under the fixed-price swap contracts have also been hedged through Gas Marketing Services with physical gas purchase contracts, thus effectively hedging the margin on the volumes associated with fixed price swap contracts at a level about two times our rolling five-year average and approximating our 2007 average per-unit margins.

Throughout the remainder of 2008, we may experience periodic restrictions in the volume of NGLs we can deliver to third party pipelines in our West region. These restrictions happen for a variety of reasons including lack of system capacity. If alternate delivery options are unavailable, such restrictions could impact our ability to recover and sell NGLs, which might otherwise have been available from our processing plants.

Margins in our olefins business are highly dependent upon continued economic growth within the global economy. A significant slow down in the economy in the United States would reduce the demand for the petrochemical products we produce in both Canada and the United States. However, based on the previously mentioned global opportunities and increasing our ownership interest in the Geismar olefins facility in July 2007, we anticipate results from our olefins business to be above 2007 levels.

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Management s Discussion and Analysis (Continued)

Gathering, processing, and other fee revenues in our West region are expected to be at or slightly above levels of previous years due to continued strong drilling activities in our core basins and the newly acquired Parachute Lateral system.

We expect fee revenues in our Gulf Coast region to be slightly above 2007 levels as we expand our Devils Tower infrastructure to serve the Blind Faith and Bass Lite prospects and increase the per-unit rate of revenue recognition for resident production at our Devils Tower facility. While we expect to continue to connect new supplies in the deepwater, this increase is expected to be partially offset by lower volumes in other deepwater areas due to natural declines. Fee revenues include gathering, processing, production handling and transportation fees.

Revenues from production areas are often subject to risks associated with the interruption and timing of product flows which can be influenced by weather and other third-party operational issues.

The per-unit rate of revenue recognition for resident production at our Devils Tower facility increased as a result of a reserve study that was completed during the first quarter of 2008. While this change will impact revenues, it will not impact the cash flows from the resident production.

We will continue to invest in facilities in the growth basins in which we provide services. We expect continued expansion of our gathering and processing systems in our Gulf Coast and West regions to keep pace with increased demand for our services. As we pursue these activities, our operating and general and administrative expenses are expected to increase.

The Venezuelan government continues its public criticism of U.S. economic and political policy, has implemented unilateral changes to existing energy related contracts, and has expropriated privately held assets within the energy and telecommunications sector. In addition, several types of confiscatory taxes continue to be implemented, escalating our concern regarding political risk in Venezuela.

Our right of way agreement with the Jicarilla Apache Nation (JAN), which covered certain gathering system assets in Rio Arriba County of northern New Mexico, expired on December 31, 2006. We currently operate our gathering assets on the JAN lands pursuant to a special business license granted by the JAN which expires August 31, 2008, and are negotiating with the JAN to sell them these gathering assets. The current special business license requires the execution of a purchase and sale agreement for these gathering assets on or before May 31, 2008. It is anticipated that this sale will be completed during the third or fourth quarter of 2008. As a result of the maturation of negotiations during the first quarter of 2008, these assets, including property, plant and equipment, have been classified as held for sale and included in *other current assets and deferred charges* on our Consolidated Balance Sheet. Current expectations are that the final terms of the sale will allow us to maintain partial revenues associated with gathering and processing services for gas produced from the JAN lands and continued operation of the gathering assets on the JAN lands through at least 2009. We believe the expected proceeds from the sale of these assets will substantially exceed their carrying value. Based on current estimated gathering volumes and range of annual average commodity prices over the past five years, we estimate that gas produced on or isolated by the JAN lands represents approximately $20 million to $30 million of the West region s annual gathering and processing revenue less related product costs.

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Management s Discussion and Analysis (Continued)

Period-Over-Period Results

	Three months ended March 31, 2008	2007
	(Millions)	
Segment revenues	$ 1,557	$ 1,002
Segment profit (loss)		
Domestic gathering & processing	$ 204	$ 123
Venezuela	26	27
Other	55	25
Indirect general and administrative expense	(24)	(21)
Total	$ 261	$ 154

In order to provide additional clarity, our management s discussion and analysis of operating results separately reflects the portion of general and administrative expense not allocated to an asset group as *indirect general and administrative expense*. These charges represent any overhead cost not directly attributable to one of the specific asset groups noted in this discussion.

Three months ended March 31, 2008 vs. three months ended March 31, 2007

The $555 million, or 55 percent, increase in *segment revenues* is largely due to:

A $230 million increase in revenues from the marketing of NGLs and olefins;

A $194 million increase in revenues from our olefins production business due primarily to the increase of our ownership interest in the Geismar olefins facility in July 2007;

A $123 million increase in revenues associated with the production of NGLs.

Segment costs and expenses increased $464 million, or 54 percent, primarily as a result of:

A $235 million increase in NGLs and olefins marketing purchases;

A $165 million increase in costs from our olefins production business;

A $26 million increase in operating expenses including higher depreciation, maintenance, gathering fuel expenses and operating taxes;

A $21 million increase in costs associated with the production of NGLs due primarily to higher natural gas prices.

The $107 million, or 69 percent, increase in Midstream s *segment profit* reflects $102 million higher NGL margins and $16 million higher equity earnings, as well as the other previously described changes in *segment revenues* and *segment costs and expenses*. A more detailed analysis of the segment profit of certain Midstream operations is presented as follows.

Domestic gathering & processing

The $81 million increase in *domestic gathering and processing segment profit* includes a $50 million increase in the West region and a $31 million increase in the Gulf Coast region.

Management s Discussion and Analysis (Continued)

The $50 million increase in our West region s *segment profit* primarily results from higher NGL margins and higher other fee revenues, partially offset by higher operating expenses and lower gathering fee revenues. The significant components of this increase include the following:

NGL margins increased $65 million in the first quarter of 2008 compared to the same period in 2007. This increase was driven by a significant increase in average per unit NGL prices, partially offset by an increase in costs associated with the production of NGLs reflecting higher natural gas prices and by lower volumes sold. The decrease in volumes sold is due primarily to an increase in inventory caused by the transition from product sales at the plant to shipping volumes through a pipeline for sale downstream.

Operating expenses increased $17 million including $7 million in higher system losses and $5 million in higher gathering fuel which were both impacted by severe winter weather conditions in the first quarter of 2008, and a full quarter of operations for our fifth train at Opal.

The $31 million increase in the Gulf Coast region s *segment profit* is primarily due to higher NGL margins, partially offset by higher operating costs and lower fee revenues. The significant components of this increase include the following:

NGL margins increased $37 million driven by higher NGL prices and higher volumes as we connect new supplies in the deepwater, partially offset by an increase in costs associated with the production of NGLs;

Fee revenues from our deepwater assets decreased $2 million due primarily to declines in producers volumes, partially offset by higher per-unit revenue recognition rates for resident production at our Devils Tower facility based on a new reserve study;

Operating expenses increased $3 million due primarily to new transportation expenses charged by Gas Pipeline in the eastern Gulf of Mexico.

<u>Other</u>

The significant components of the $30 million increase in *segment profit* of our other operations include the following:

$29 million in higher margins from our olefins production business due primarily to higher prices of NGL products produced in our Canadian olefins operations and the increase of our ownership interest in the Geismar olefins facility in July 2007;

$10 million higher Discovery Producer Services, L.L.C. equity earnings primarily due to higher NGL margins and volumes;

$6 million in foreign exchange gains in the first quarter of 2008 related to the revaluation of current assets held in U.S. dollars within our Canadian operations, compared to $1 million in losses in the first quarter of 2007;

$5 million higher Aux Sable Liquid Products L.P. equity earnings primarily due to favorable processing margins.

These increases are partially offset by:

The absence of an $8 million reversal of a maintenance accrual in 2007;

$5 million higher maintenance expenses due primarily to the increase in ownership of the Geismar olefins facility in July 2007;

$4 million in lower margins related to the marketing of olefins due to more unfavorable changes in pricing while product was in transit during 2008 as compared to 2007.

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Management s Discussion and Analysis (Continued)

Gas Marketing Services

Gas Marketing Services (Gas Marketing) primarily supports our natural gas businesses by providing marketing and risk management services, which include marketing and hedging the gas produced by Exploration & Production and procuring fuel and shrink gas and hedging natural gas liquids sales for Midstream. In addition, Gas Marketing manages various natural gas-related contracts such as transportation, storage, and related hedges, including certain legacy natural gas contracts and positions, and provides similar services to third parties, such as producers.

Overview of Three Months Ended March 31, 2008

Gas Marketing s improved operating results for the first three months of 2008 compared to the first three months of 2007 reflect a favorable change in unrealized mark-to-market gains and losses due primarily to favorable price movements on derivatives that are not designated as hedges for accounting purposes or do not qualify for hedge accounting.

Outlook for the Remainder of 2008

For the remainder of 2008, Gas Marketing intends to focus on providing services that support our natural gas businesses. Certain legacy natural gas contracts and positions from our former Power segment remain in the Gas Marketing segment. Gas Marketing s earnings may continue to reflect mark-to-market volatility from commodity-based derivatives that represent economic hedges but are not designated as hedges for accounting purposes or do not qualify for hedge accounting. However, this mark-to-market volatility is expected to be significantly reduced compared with previous levels.

Period-Over-Period Results

	Three months ended March 31,	
	2008	2007
	(Millions)	
Realized revenues	$ 1,647	$ 1,328
Net forward unrealized mark-to-market gains (losses)	3	(40)
Segment revenues	1,650	1,288
Costs and operating expenses	1,625	1,316
Gross margin	25	(28)
Selling, general and administrative expense	4	2
Segment profit (loss)	$ 21	$ (30)

Three months ended March 31, 2008 vs. three months ended March 31, 2007

Realized revenues represent (1) revenue from the sale of natural gas or completion of energy-related services and (2) gains and losses from the net financial settlement of derivative contracts. Realized revenues increased $319 million primarily due to an increase in physical natural gas revenue as a result of a 19 percent increase in average prices on physical natural gas sales and a 3 percent increase in natural gas sales volumes. This is partially offset by a decrease in net financial settlements of derivative contracts.

Net forward unrealized mark-to-market gains (losses) primarily represent changes in the fair values of certain legacy derivative contracts with a future settlement or delivery date that are not designated as hedges for accounting purposes or do not qualify for hedge accounting. The favorable change of $43 million in unrealized mark-to-market revenues is primarily the result of favorable price movements on these derivative contracts. This change also includes an $11 million favorable impact due to considering our own nonperformance risk in estimating the fair value of our derivative liabilities.

The $309 million increase in Gas Marketing s *cost and operating expenses* is primarily due to a 17 percent increase in average prices on physical natural gas purchases.

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Management s Discussion and Analysis (Continued)

The $51 million improvement in *segment profit (loss)* is primarily due to a favorable change in unrealized mark-to-market gains and losses primarily due to favorable price movements on derivatives that are not designated as hedges for accounting purposes or do not qualify for hedge accounting, an improvement in accrual gross margin, and the favorable impact of applying a credit reserve for nonperformance risk on our own derivative liabilities in accordance with the implementation of SFAS 157.

Other

Period-Over-Period Results

	Three months ended March 31,	
	2008	2007
	(Millions)	
Segment revenues	$ 6	$ 7
Segment profit	$ 1	$

The results of our Other segment are relatively comparable to the prior year.

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Management s Discussion and Analysis (Continued)

Energy Trading Activities

Fair Value of Trading and Nontrading Derivatives

The chart below reflects the fair value of derivatives held for trading purposes as of March 31, 2008. We have reported the fair value of a portion of these derivatives in assets and liabilities of discontinued operations. (See Note 3 of Notes to Consolidated Financial Statements.)

Net Assets (Liabilities) Trading (Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$ 18	$ (2)	$	$	$	$ 16

As the table above illustrates, we are not materially engaged in trading activities. However, we hold a substantial portfolio of nontrading derivative contracts. Nontrading derivative contracts are those that hedge or could possibly hedge forecasted transactions on an economic basis. We have designated certain of these contracts as cash flow hedges of Exploration & Production s forecasted sales of natural gas production and Midstream s forecasted sales of natural gas liquids under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133). Of the total fair value of nontrading derivatives, SFAS 133 cash flow hedges had a net liability value of $465 million as of March 31, 2008. The chart below reflects the fair value of derivatives held for nontrading purposes as of March 31, 2008, for Gas Marketing Services, Exploration & Production, Midstream, and nontrading derivatives reported in assets and liabilities of discontinued operations.

Net Assets (Liabilities) Nontrading (Millions)

To be Realized in 1-12 Months (Year 1)	To be Realized in 13-36 Months (Years 2-3)	To be Realized in 37-60 Months (Years 4-5)	To be Realized in 61-120 Months (Years 6-10)	To be Realized in 121+ Months (Years 11+)	Net Fair Value
$ (334)	$ (223)	$ (4)	$	$	$ (561)

Counterparty Credit Considerations

We include an assessment of the risk of counterparty nonperformance in our estimate of fair value for all contracts. Such assessment considers (1) the credit rating of each counterparty as represented by public rating agencies such as Standard & Poor s and Moody s Investors Service, (2) the inherent default probabilities within these ratings, (3) the regulatory environment that the contract is subject to and (4) the terms of each individual contract.

Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We continually assess this risk. We have credit protection within various agreements to call on additional collateral support if necessary. At March 31, 2008, we held collateral support, including letters of credit, of $16 million.

Management s Discussion and Analysis (Continued)

The gross credit exposure from our derivative contracts, a portion of which is included in assets of discontinued operations as of March 31, 2008 (see Note 3 of Notes to Consolidated Financial Statements), is summarized below.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	
Gas and electric utilities	$ 137	$ 139
Energy marketers and traders	118	1,555
Financial institutions	2,266	2,266
Other		1
	$ 2,521	3,961
Credit reserves		(3)
Gross credit exposure from derivatives		$ 3,958

We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts. The net credit exposure from our derivatives as of March 31, 2008, is summarized below.

Counterparty Type	Investment Grade (a)	Total
	(Millions)	
Gas and electric utilities	$ 2	$ 3
Energy marketers and traders	2	5
Financial institutions	48	48
Other		
	$ 52	56
Credit reserves		(3)
Net credit exposure from derivatives		$ 53

(a) We determine investment grade primarily using publicly available credit ratings. We included counterparties with a minimum Standard &

Poor s rating of BBB or Moody s Investors Service rating of Baa3 in investment grade. We also classify counterparties that have provided sufficient collateral, such as cash, standby letters of credit, adequate parent company guarantees, and property interests, as investment grade.

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Management s Discussion and Analysis (Continued)

Management s Discussion and Analysis of Financial Condition

Outlook

We believe we have, or have access to, the financial resources and liquidity necessary to meet future requirements for working capital, capital and investment expenditures and debt payments while maintaining a sufficient level of liquidity to reasonably protect against unforeseen circumstances requiring the use of funds. We also expect to maintain our investment grade status. For the remainder of 2008, we expect to maintain liquidity of at least $1 billion from cash and cash equivalents and unused revolving credit facilities. We maintain adequate liquidity to manage margin requirements related to significant movements in commodity prices, unplanned capital spending needs, near term scheduled debt payments, and litigation and other settlements. We expect to fund capital and investment expenditures, debt payments, dividends, stock repurchases, and working capital requirements through cash flow from operations, which is currently estimated to be between $2.5 billion and $2.9 billion in 2008, proceeds from debt issuances and sales of units of Williams Partners L.P. and Williams Pipeline Partners L.P., as well as cash and cash equivalents on hand as needed.

We entered 2008 positioned for growth through disciplined investments in our natural gas business. Examples of this planned growth include:

- Exploration & Production will continue to maintain its development drilling program in its key basins of Piceance, Powder River, San Juan, Arkoma, and Fort Worth.

- Gas Pipeline will continue to expand its system to meet the demand of growth markets.

- Midstream will continue to pursue significant deepwater production commitments and expand capacity in the western United States.

We estimate capital and investment expenditures will total approximately $2.6 billion to $2.95 billion in 2008, with approximately $2 billion to $2.4 billion to be incurred over the remainder of the year. Of the total estimated 2008 capital expenditures, $1.45 billion to $1.65 billion is related to Exploration & Production. Also within the total estimated expenditures for 2008 is approximately $180 million to $260 million for compliance and maintenance-related projects at Gas Pipeline, including Clean Air Act compliance.

Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

- Lower than expected levels of cash flow from operations due to commodity pricing volatility. To mitigate this exposure, both our Exploration & Production and Midstream segments utilize hedging programs to manage commodity price risk.

- Sensitivity of margin requirements associated with our marginable commodity contracts. As of March 31, 2008, we estimate our exposure to additional margin requirements through the remainder of 2008 to be no more than $163 million, using a statistical analysis at a 99 percent confidence level.

- Exposure associated with our efforts to resolve regulatory and litigation issues. (See Note 12 of Notes to Consolidated Financial Statements.)

- The impact of a general economic downturn, including any associated volatility in the credit markets and our access to liquidity in the capital markets.

Overview

In first-quarter 2008, we purchased approximately 4 million shares of our common stock for $126 million under our $1 billion common stock repurchase program at an average cost of $33.95 per share. (See Note 11 of Notes to Consolidated Financial Statements.) Since the program s inception in third-quarter 2007, we have purchased approximately 20 million shares of our common stock for approximately $652 million (including transaction costs).

Management s Discussion and Analysis (Continued)

In January 2008, Williams Pipeline Partners L.P. completed its initial public offering of 16.25 million common units at a price of $20 per unit. In February 2008, the underwriters exercised their right to purchase an additional 1.65 million common units at the same price. (See Note 2 of Notes to Consolidated Financial Statements.)

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments.

On November 28, 2007, Transco filed a formal stipulation and agreement with the FERC resolving all substantive issues in Transco s pending 2006 rate case. On March 7, 2008, the FERC approved the agreement without modification. The agreement is effective June 1, 2008, and refunds will be due on July 31, 2008.

In January 2008, Transco borrowed $100 million under our $1.5 billion unsecured credit facility. These proceeds were used to retire their $100 million 6.25 percent senior unsecured notes due January 15, 2008.

Transco s $75 million adjustable rate unsecured note, due April 15, 2008, was reclassified as long-term debt as a result of a refinancing in April 2008 under our $1.5 billion unsecured credit facility.

Credit ratings

Standard & Poor s rates our senior unsecured debt at BB+ and our corporate credit at BBB- with a stable ratings outlook. With respect to Standard & Poor s, a rating of BBB or above indicates an investment grade rating. A rating below BBB indicates that the security has significant speculative characteristics. A BB rating indicates that Standard & Poor s believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor s may modify it s ratings with a + or a sign to show the obligor s relative standing within a major rating category.

Moody s Investors Service rates our senior unsecured debt at Baa3 with a stable ratings outlook. With respect to Moody s, a rating of Baa or above indicates an investment grade rating. A rating below Baa is considered to have speculative elements. The 1 , 2 and 3 modifiers show the relative standing within a major category. A 1 indicates th an obligation ranks in the higher end of the broad rating category, 2 indicates a mid-range ranking, and 3 ranking at the lower end of the category.

Fitch Ratings rates our senior unsecured debt at BBB- with a stable ratings outlook. With respect to Fitch, a rating of BBB or above indicates an investment grade rating. A rating below BBB is considered speculative grade. Fitch may add a + or a sign to show the obligor s relative standing within a major rating category.

Liquidity

Our internal and external sources of liquidity include cash generated from our operations, bank financings, proceeds from the issuance of long-term debt and equity securities, and proceeds from asset sales. While most of our sources are available to us at the parent level, others are available to certain of our subsidiaries, including equity and debt issuances from Williams Partners L.P. and Williams Pipeline Partners, L.P., our master limited partnerships. Our ability to raise funds in the capital markets will be impacted by our financial condition, interest rates, market conditions, and industry conditions.

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Management s Discussion and Analysis (Continued)

Available Liquidity

	March 31, 2008 (Millions)
Cash and cash equivalents*	$ 2,240
Available capacity under our four unsecured revolving and letter of credit facilities totaling $1.2 billion	921
Available capacity under our $1.5 billion unsecured revolving and letter of credit facility**	1,122
Available capacity under Williams Partners L.P. s $450 million five-year senior unsecured credit facility***	200
	$ 4,483

* *Cash and cash equivalents* includes $7 million of funds received from third parties as collateral. The obligation for these amounts is reported as *accrued liabilities* on the Consolidated Balance Sheet. Also included is $504 million of cash and cash equivalents that is being utilized by certain subsidiary and international operations.

** Northwest Pipeline and Transco each have access to $400 million under this facility to the extent not utilized by us. At March 31, 2008, Northwest Pipeline has $250 million and Transco has $100 million in loans outstanding under this facility. In April 2008, Transco borrowed an additional $75 million to retire matured notes.

*** This facility is only available to Williams Partners L.P.

The above table does not include a $10 million auction rate security that is now classified within *other assets and deferred charges* due to recent auction failures. We have the intent and ability to hold this investment grade security until we are able to realize its face value. We hold no other auction rate securities at March 31, 2008.

In addition to the above, Northwest Pipeline and Transco have shelf registration statements available for the issuance of up to $350 million aggregate principal amount of debt securities.

Williams Partners L.P. has a shelf registration statement available for the issuance of approximately $1.2 billion aggregate principal amount of debt and limited partnership unit securities.

In addition, at the parent-company level, we have a shelf registration statement that allows us to issue publicly registered debt and equity securities as needed.

Exploration & Production has an unsecured credit agreement, through February 2012, with certain banks which serves to reduce our usage of cash and other credit facilities for margin requirements related to our natural gas hedging activities as well as lower transaction fees.

Sources (Uses) of Cash

	Three months ended March 31, 2008	Three months ended March 31, 2007
	(Millions)	
Net cash provided (used) by:		
Operating activities	$ 793	$ 299
Financing activities	162	(116)
Investing activities	(414)	(641)
Increase (decrease) in cash and cash equivalents	$ 541	$ (458)

Operating activities

Our *net cash provided by operating activities* for the three months ended March 31, 2008, increased from the same period in 2007 due primarily to the increase in our operating results. Included in the 2008 operating results is approximately $74 million of cash received related to a February 2008 favorable ruling from the Alaska Supreme Court in a matter involving pipeline transportation rates charged to our former Alaska refinery in prior periods.

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Management s Discussion and Analysis (Continued)

Financing activities

See Overview, within this section, for a discussion of first quarter 2008 debt issuances, retirements, stock repurchases, and sales of Williams Pipeline Partners L.P. common units.

During the first quarter of 2008, we paid a quarterly dividend of 10 cents per common share, totaling $59 million, compared to a quarterly dividend of 9 cents per common share, totaling $54 million, for the first quarter of 2007.

Investing activities

During the first three months of 2008, capital expenditures totaled $579 million and were primarily related to Exploration & Production s drilling activity.

In January 2008, we sold a contractual right to a production payment on certain future international hydrocarbon production for approximately $148 million. We have received $118 million in cash and $29 million has been placed in escrow subject to certain post-closing conditions and adjustments.

During the first three months of 2007 we purchased $173 million and received $45 million from the sale of auction rate securities. These were utilized as a component of our overall cash management program.

Off-balance sheet financing arrangements and guarantees of debt or other commitments

We have various other guarantees and commitments which are disclosed in Note 12 of Notes to Consolidated Financial Statements. We do not believe these guarantees or the possible fulfillment of them will prevent us from meeting our liquidity needs.

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Item 3
Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our interest rate risk exposure is primarily associated with our debt portfolio and has not materially changed during the first three months of 2008. See Note 9 of Notes to Consolidated Financial Statements.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas and natural gas liquids, as well as other market factors, such as market volatility and commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our proprietary trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to changes in energy-commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted, and changes in interest rates. We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios.

Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolio in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Derivative contracts designated as normal purchases or sales under SFAS 133 and nonderivative energy contracts have been excluded from our estimation of value at risk.

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. Our value at risk for contracts held for trading purposes was approximately $1 million at both March 31, 2008 and December 31, 2007.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from the following activities:

Segment	Commodity Price Risk Exposure
Exploration & Production	Natural gas sales
Midstream	Natural gas purchases NGL sales
Gas Marketing Services	Natural gas purchases and sales

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The value at risk for all derivative contracts held for nontrading purposes was $49 million at March 31, 2008, and $24 million at December 31, 2007. A portion of these derivative contracts are included in our assets and liabilities of discontinued operations, but these had a value at risk amount of zero for both periods.

Certain of the other derivative contracts held for nontrading purposes are accounted for as cash flow hedges under SFAS 133. Though these contracts are included in our value-at-risk calculation, any changes in the effective portion of the fair value of these hedge contracts would generally not be reflected in earnings until the associated hedged item affects earnings.

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Item 4
Controls and Procedures

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) (Disclosure Controls) was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our Disclosure Controls or our internal controls over financial reporting (Internal Controls) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and the Internal Controls will be modified as systems change and conditions warrant.

First-Quarter 2008 Changes in Internal Controls Over Financial Reporting

There have been no changes during the first quarter of 2008 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 12 of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

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Item 1A. Risk Factors

Our businesses are subject to complex government regulations. The operation of our businesses might be adversely affected by changes in these regulations or in their interpretation or implementation, or the introduction of new laws or regulations applicable to our businesses or our customers.

Existing regulations might be revised or reinterpreted, new laws and regulations might be adopted or become applicable to us, our facilities or our customers, and future changes in laws and regulations might have a detrimental effect on our business. Specifically, the Colorado Oil & Gas Conservation Commission recently published proposed rules that could increase our costs of permitting and environmental compliance, may affect our ability to meet our anticipated drilling schedule and therefore may have a material effect on our results of operations. Over the past few years, certain restructured energy markets have experienced supply problems and price volatility. In some of these markets, proposals have been made by governmental agencies and other interested parties to re-regulate areas of these markets which have previously been deregulated. Various forms of market controls and limitations including price caps and bid caps have already been implemented and new controls and market restructuring proposals are in various stages of development, consideration and implementation. We cannot assure you that changes in market structure and regulation will not adversely affect our business and results of operations. We also cannot assure you that other proposals to re-regulate will not be made or that legislative or other attention to these restructured energy markets will not cause the deregulation process to be delayed or reversed or otherwise adversely affect our business and results of operations.

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Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[1]	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
January 1 January 31, 2008	1,553,800	$ 35.68	1,553,800	$ 418,788,997
February 1 February 29, 2008				
March 1 March 31, 2008	2,163,700	$ 32.67	2,163,700	$ 348,100,326
Total	3,717,500	$ 33.93	3,717,500	$ 348,100,326

1 We announced a stock repurchase program on July 20, 2007. Our board of directors has authorized the repurchase of up to $1 billion of the company s common stock. The stock repurchase program has no expiration date. We intend to purchase shares of our stock from time to time in open market transactions or through privately negotiated or

structured transactions at our discretion, subject to market conditions and other factors.

Item 6. Exhibits

(a) The exhibits listed below are filed or furnished as part of this report:

Exhibit 10.1* Form of 2008 Performance-Based Restricted Stock Unit Agreement among Williams and certain employees and officers (filed as Exhibit 99.1 to our Current Report on Form 8-K filed February 29, 2008).

Exhibit 10.2* Form of 2008 Restricted Stock Unit Agreement among Williams and certain employees and officers (filed as Exhibit 99.2 to our Current Report on Form 8-K filed February 29, 2008).

Exhibit 10.3* Form of 2008 Nonqualified Stock Option Agreement among Williams and certain employees and officers (filed as Exhibit 99.3 to our Current Report on Form 8-K filed February 29, 2008).

Exhibit 10.4 Confidential Separation Agreement and Release between The Williams Companies, Inc. and Michael P. Johnson dated April 2, 2008.

Exhibit 12 Computation of Ratio of Earnings to Fixed Charges.

Exhibit 31.1 Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 31.2 Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 32 Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Each such exhibit has heretofore been filed with the SEC as part of the filing indicated and is incorporated herein by reference.

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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.

THE WILLIAMS COMPANIES, INC.
(Registrant)

/s/ Ted T. Timmermans
Ted T. Timmermans
Controller (Duly Authorized Officer and
Principal Accounting Officer)

May 1, 2008