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United States
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): June 1, 2004

The Williams Companies, Inc.

(Exact name of registrant as specified in its charter)

Delaware	1-4174	73-0569878
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

One Williams Center, Tulsa, Oklahoma	74172
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: 918/573-2000

Not Applicable

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240-14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 8.01. Other Events

Effective September 21, 2004, and due in large part to FERC Order 2004, management and decision-making control of The Williams Companies, Inc. (“Williams”) equity method investment in the Aux Sable gas processing plant and related business was transferred from its Midstream segment to its Power segment.

Included here are the restated consolidated financial statements and schedule of Williams as of December 31, 2003 and 2002, and for the three years ended December 31, 2003 and the related report of independent registered public accounting firm, and the restated unaudited consolidated financial statements as of June 30, 2004, March 31, 2004 and December 31, 2003, and for the six month periods ended June 30, 2004 and 2003 and the three month periods ended June 30, 2004 and 2003 and March 31, 2004 and 2003. In addition, certain other exhibits labeled below as “restated” have been restated to reclassify the results of operations of Aux Sable from our Midstream segment to our Power segment.

This Current Report on Form 8-K is being filed as a revision to our Annual Report on Form 10-K for the fiscal year ended December 31, 2003, as restated and amended; our Quarterly Report on Form 10-Q for the three months ended March 31, 2004, as restated and amended; and our Quarterly Report on Form 10-Q for the three and six months ended June 30, 2004, as amended. Unless the passage of time has rendered incorrect as of the time of its original filing any other information contained in the original Form 10-K or Form 10-Q, such information has not been updated in this Form 8-K. To update all other information, we hereby incorporate by reference herein all information contained in our Quarterly Reports on Form 10-Q for the quarter ended March 31, 2004, June 30, 2004 and September 30, 2004, other than the financial statements and related footnotes thereto contained in such Form.

Item 9.01. Financial Statements and Exhibits.

(a) None

(b) None

(c) Exhibits

Exhibit 23	Consent of Ernst & Young LLP, Independent Registered Public Accounting Firm
Exhibit 99.1	Management’s Discussion and Analysis of Financial Condition and Results of Operations for the year ended December 31, 2003 compared to the year ended December 31, 2002 and the year ended December 31, 2002 compared to the year ended December 31, 2001 (Restated)
Exhibit 99.2	Financial Statements and Supplementary Data, including Consolidated Financial Statements as of December 31, 2003 and 2002 and for the three years ended December 31, 2003, Supplementary Data and Schedule II — Valuation and Qualifying Accounts (Restated), with Report of Ernst & Young LLP, Independent Registered Public Accounting Firm.
Exhibit 99.3	Financial Statements, including the Consolidated Financial Statements as of March 31, 2004 and December 31, 2003 and for the three-month periods ended March 31, 2004 and 2003 (Restated)
Exhibit 99.4	Management’s Discussion and Analysis of Financial Condition and Results of Operations for the three months ended March 31, 2004 compared to the three months ended March 31, 2003 (Restated)
Exhibit 99.5	Financial Statements, including the Consolidated Financial Statements as of June 30, 2004 and December 31, 2003 and for the three month and six month periods ended June 30, 2004 and 2003 (Restated)
Exhibit 99.6	Management’s Discussion and Analysis of Financial Condition and Results of Operations for the three and six months ended June 30, 2004 compared to the three and six months ended June 30, 2003 (Restated)

Certain matters discussed in this report, excluding historical information, include forward-looking statements — statements that discuss Williams' expected future results based on current and pending business operations. Williams makes these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

Forward-looking statements can be identified by words such as "anticipates," "believes," "expects," "planned," "scheduled" or similar expressions. Although Williams believes these forward-looking statements are based on reasonable assumptions, statements made regarding future results are subject to a number of assumptions, uncertainties and risks that may cause future results to be materially different from the results stated or implied in this document. Additional information about issues that could lead to material changes in performance is contained in Williams' 2003 Form 10-K.

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

THE WILLIAMS COMPANIES, INC.

Date: November 5, 2004

/s/ Gary R. Belitz

Name: Gary R. Belitz
Title: Controller (Duly Authorized Officer and Principal Accounting Officer)

INDEX TO EXHIBITS

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EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following registration statements on Form S-3 and Form S-4, and related prospectuses and in the following registration statements on Form S-8 of The Williams Companies, Inc. of our report dated February 18, 2004 (except for the matter described in the second paragraph in Note 2, as to which the date is September 14, 2004, and except for Note 19, as to which the date is November 2, 2004), with respect to the consolidated financial statements and schedule of The Williams Companies, Inc. included in this Current Report on Form 8-K:

Form S-3:	Registration No. 333-20929; Registration No. 333-35097; Registration No. 333-29185; Registration No. 333-70394; Registration No. 333-20927; Registration No. 333-27311; Registration No. 333-35101; Registration No. 333-106504; Registration No. 333-85540;
Form S-4:	Registration No. 333-57416; Registration No. 333-63202; Registration No. 333-101788; Registration No. 333-72982; Registration No. 333-85566; Registration No. 333-85568; Registration No. 333-119077;
Form S-8:	Registration No. 33-58971; Registration No. 3-58969; Registration No. 33-56521; Registration No. 33-58671; Registration No. 333-11151; Registration No. 333-40721; Registration No. 333-48945; Registration No. 333-90265; Registration No. 333-76929; Registration No. 333-66474; Registration No. 333-85542; Registration No. 333-03957; Registration No. 333-51994; Registration No. 333-85546; Registration No. 333-61597

/s/ ERNST & YOUNG LLP

Tulsa, Oklahoma
November 2, 2004

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW OF 2003

In February 2003, we outlined our planned business strategy in response to the events that significantly impacted the energy sector and our company during late 2001 and 2002, including the collapse of Enron and the severe decline of the telecommunications industry. The plan focused upon migrating to an integrated natural gas business comprised of a strong, but smaller, portfolio of natural gas businesses, reducing debt and increasing our liquidity through asset sales, strategic levels of financing and reductions in operating costs. The plan provided us with a clear strategy to address near-term and medium-term debt and liquidity issues, to de-leverage the company with the objective of returning to investment grade status and to develop a balance sheet capable of supporting and ultimately growing our remaining businesses. A component of our plan was to reduce the risk and liquidity requirements of the Power segment while realizing the value of Power's portfolio.

COMPANY RESTRUCTURING

During 2003, we successfully executed the following critical components of our restructuring plan:

- generated cash proceeds of approximately $3 billion from the sale of assets;

- sustained core business earnings capacity through completed system expansions at Gas Pipeline, continued drilling activity at Exploration & Production and continued investment in deepwater activities within Midstream;

- repaid $3.2 billion of debt through scheduled maturities and early extinguishment of debt and accessed the public debt markets available to us primarily to refinance $2 billion of higher cost debt; and

- continued rationalization of our cost structure, including a 28 percent reduction in selling, general and administrative (SG&A) costs from continuing operations and a 39 percent reduction in general corporate expenses.

ADDRESSING LIQUIDITY

Through these efforts, we satisfied key liquidity issues facing us in the form of scheduled debt maturities. These were primarily the Williams Production RMT Company (RMT) note payable (RMT Note) of approximately $1.15 billion (including certain contractual fees and deferred interest) due on July 25, 2003, and $1.4 billion of senior unsecured 9.25 percent notes due March 15, 2004. As a result of the proceeds generated from asset sales and proceeds from the issuance of $500 million of long-term debt, we prepaid the RMT Note in May 2003. During the fourth quarter, we completed tender offers that prepaid approximately $721 million of the senior unsecured 9.25 percent notes and approximately $230 million of other notes and debentures. With approximately $2.3 billion available cash on hand at the end of 2003, we have the capacity to pay the $679 million balance of the senior unsecured 9.25 percent notes upon their maturity.

During 2004, we expect to maintain cash/liquidity levels of at least $1 billion in excess of our immediate needs. While improved during 2003, we have limited access to the capital markets and must maintain liquidity at a level to manage our operations and meet unforeseen or extraordinary calls on cash. Additionally, we will pursue establishing new revolving and letter of credit facilities to reduce cash requirements associated with our current facility.

EXITING THE POWER BUSINESS

We are pursuing a strategy of exiting the Power business. However, market conditions have contributed to the difficulty of, and could delay, a full, immediate exit from this business. In 2003, we generated in excess of $600 million from the sale, termination or liquidation of Power contracts and assets. During the year, we continued to manage our portfolio to reduce risk, to generate cash and to fulfill contractual commitments. We are also pursuing our goal to resolve the remaining legal and regulatory issues associated with the business.

During 2003, we engaged financial advisors to assist and advise with this effort. Because market conditions may change, and we cannot determine the impact of this on a buyer's point of view, amounts ultimately received in any portfolio sale, contract liquidation or realization may be significantly different from the estimated economic value or carrying values reflected in the Consolidated Balance Sheet. In addition, our tolling agreements are not derivatives and thus have no carrying value in the Consolidated Balance Sheet pursuant to the application of Emerging Issues Task Force (EITF) Issue No. 02-3 (EITF 02-3). Based on current market conditions, certain of these agreements are forecasted to realize significant future losses. It is possible that we may sell contracts for less than their carrying value or enter into agreements to terminate certain obligations, either of which could result in significant future loss recognition or reductions of future cash flows.

On a consolidated basis, the net book value at December 31, 2003 of Power's portfolio and other long-lived assets were in excess of $800 million, while other net assets of Power, including net working capital, were in excess of $400 million.

OUTLOOK FOR 2004

Entering 2004, our plan is focused upon the following objectives:

- Sustain solid core business performance, including increased capital allocated to Exploration & Production.

  We expect cash flow from operations to be sufficient to meet our 2004 capital spending plan of $700 to $800 million and to generate additional cash to be available for debt reduction.

- Continue reduction of debt and selective refinancing of certain instruments.

  We expect to aggressively reduce debt in 2004. We have approximately $936 million in scheduled maturities coming due throughout the year and anticipate using available cash flow, proceeds from assets sales and the release of collateral from credit facilities to further reduce debt levels.

- Maintain investment discipline.

  We have implemented the Economic Value Added(R) (EVA(R)) financial management system as a financial framework for use in evaluating our business decisions and as a major component for determining incentive compensation. We will invest selectively in those projects that are projected to add value to the company through EVA(R) improvement.

Key execution steps will include the completion of planned asset sales, which are estimated to generate proceeds of approximately $800 million in 2004, additional reduction of SG&A costs, replacing our cash-collateralized letter of credit and revolver facility with facilities that do not encumber cash and continued efforts to exit the power business. Some factors that present obstacles that could prevent us from achieving these objectives include:

- volatility of commodity prices;
- ongoing shareholder and Power-related litigation;
- lower than expected cash flow from continuing operations;
- general economic and industry downturn; and
- unfavorable capital market conditions.

We continue to address these risks through utilization of commodity hedging strategies, focused efforts to resolve and/or respond to litigation claims, managing our business with an emphasis upon generating cash and retaining and developing those business operations serving key economic and energy needs.

CRITICAL ACCOUNTING POLICIES & ESTIMATES

Our financial statements reflect the selection and application of accounting policies which require management to make significant estimates and assumptions. The selection of these has been discussed with our Audit Committee. We believe that the following are the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

REVENUE RECOGNITION -- DERIVATIVES

We hold a substantial portfolio of derivative contracts for a variety of purposes. Many of these are designated in hedge positions; hence, changes in their fair value are not reflected in earnings until the associated hedged item impacts earnings. Others have not been designated as hedges or do not qualify for hedge accounting. The net change in fair value of these contracts represents unrealized gains and losses and is recognized in income currently (marked-to-market). The fair value for each of these derivative contracts is determined based on the nature of the transaction and the market in which transactions are executed. We also incorporate assumptions and judgments about counterparty performance and credit considerations in our determination of fair value. Certain contracts are executed in exchange traded or over-the-counter markets where quoted prices in active markets may exist. Transactions are also executed in exchange-traded or over-the-counter markets for which market prices may exist, but which may be relatively inactive with limited price transparency. Hence, the ability to determine the fair value of the contract is more subjective than if an independent third party quote were available. A limited number of transactions are also executed for which quoted market prices are not available. Determining fair value for these contracts involves assumptions and judgments when estimating prices at which market participants would transact if a market existed for the contract or transaction. We estimate the fair value of these various derivative contracts by incorporating information about commodity prices in actively quoted markets, quoted prices in less active markets, and other market fundamental analysis. The estimated fair value of all these derivative contracts is continually subject to change as the underlying energy commodity market changes and as management's assumptions and judgments change.

Additional discussion of the accounting for energy contracts at fair value is included in Note 1 of Notes to Consolidated Financial Statements, Energy Trading Activities, and Item 7A -- Qualitative and Quantitative Disclosures About Market Risk, as restated.

VALUATION OF DEFERRED TAX ASSETS AND TAX CONTINGENCIES

We have deferred tax assets resulting from certain investments and businesses that have a tax basis in excess of the book basis and from tax carry-forwards generated in the current and prior years. We must evaluate whether we will ultimately realize these tax benefits and establish a valuation allowance for those that may not be realizable. This evaluation considers tax planning strategies, including assumptions about the availability and character of future taxable income. At December 31, 2003, we have $700 million of deferred tax assets for which a $68 million valuation allowance has been established. When assessing the need for a valuation allowance, we considered forecasts of future company performance, the estimated impact of potential asset dispositions and our ability and intent to execute tax planning strategies to utilize tax carryovers. Based on our projections, we believe that it is probable that we can utilize our year-end 2003 federal tax carryovers prior to their expiration. See Note 5 of Notes to Consolidated Financial Statements for additional information regarding the tax carryovers. The ultimate realized amount of deferred tax assets could be materially different from those recorded, as influenced by potential changes in jurisdictional income tax laws and the circumstances surrounding the actual realization of these assets.

We frequently face challenges from domestic and foreign tax authorities regarding the amount of taxes due. These challenges include questions regarding the timing and amount of deductions and the allocation of income among various tax jurisdictions. In evaluating the liability associated with our various filing positions, we record a liability for probable tax contingencies. The ultimate disposition of these contingencies could have a material impact on net cash flows. To the extent we were to prevail in matters for which accruals have been established or required to pay amounts in excess of our accrued liability, our effective tax rate in a given financial statement period may be materially impacted.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

We evaluate our long-lived assets and investments for impairment when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value of certain long-lived assets or the decline in carrying value of an investment is other-than-temporary. In addition to those long-lived assets and investments for which impairment charges were recorded (see Notes 2, 3 and 4 of Notes to Consolidated Financial Statements), many others were reviewed for which no impairment was required. Our computations utilized judgments and assumptions in the following areas:

- the probability that we would sell an asset or continue to hold and use it;
- undiscounted future cash flows if an asset is held for use;
- estimated fair value of the asset;
- estimated sales proceeds if an asset is sold;
- form and timing of the asset disposition; and
- counterparty performance considerations under contracted sales transactions.

Our Alaska refining, retail and pipeline operations are classified as "held for sale" at December 31, 2003. They are currently under contract to be sold as a single disposal group. This sale is expected to close during the first quarter of 2004. These assets were written down to fair value less cost to sell during 2003 based on the assumption that they would be sold as one disposal group. If events were to occur that caused us to divide this disposal group or to separately evaluate the individual assets within the disposal group for impairment, certain assets within that group could require an additional impairment.

We have entered into a structured sales transaction for our investment in a foreign telecommunications company. In our review of this investment for potential impairment, we assumed that the counterparty would perform under the agreement. If the counterparty is unable to fully perform, an impairment of up to $22 million could be necessary.

We own an equity investment in Longhorn Partners Pipeline L.P., a petroleum products pipeline still under development. During 2003, we recognized an impairment of a portion of our investment based on the terms of a recapitalization plan that closed in February 2004. We estimated the fair value of our remaining equity investment based on discounted future cash flows from the project. Because the pipeline is not yet operational, this estimate involved significant judgment, including:

- expected in service date;
- duration of operational ramp up;
- ultimate annual volume throughput;
- ability to obtain external debt financing in the future;
- risk-weighted discount rate; and
- cash flow projections.

A decrease of 10 percent in our estimate of fair value of this investment would result in an additional impairment of approximately $8 million.

We own a 14.6 percent equity interest in Aux Sable Liquid Products LP, a natural gas liquids extraction and fractionation facility. During 2003, we performed an impairment review of our investment in Aux Sable as current operating results and cash flow projections suggested that a decline in the fair value of this investment below our carrying value could exist. We estimated the fair value of our investment based on a projection of discounted cash flows of Aux Sable. Based upon our analysis, we concluded that the estimated fair value of our investment was below the carrying value with little likelihood that the value would recover above our carrying value over the near term. As a result, during 2003 we recorded a $14.1 million impairment of this investment to its estimated fair value. Our projections are highly sensitive to changes in volumes and commodity pricing projections. An additional 10 percent decline in the projected fair value of this investment could result in an additional $4 million charge against our operating results if that decline was determined to be other than temporary.

Our Gulf Liquids New River Project LLC (Gulf Liquids) operations are classified as "held for sale" at December 31, 2003. These assets were written down to fair value less costs to sell during 2003. We estimated fair value based on probability-weighted analysis that considered sales price negotiations, salvage value estimates, and discounted future cash flows. This estimate involved significant judgment, including:

- commodity pricing;

- probability weighting of the different scenarios; and

- range of estimated sales proceeds, salvage value and future cash flows.

The estimated cash flows from the various scenarios ranged approximately $15 million above and below our estimated fair value.

We evaluated certain asset groups not yet held for sale for impairment because of the possibility that we could dispose of these assets pursuant to our strategy to sell additional assets in 2004. Our current estimates of the recoverability of these assets indicate that no impairment is necessary. A significant assumption in the evaluation of one asset group in this analysis is the probability associated with selling the asset group versus continuing to hold it for use. We currently believe we are more likely to continue to hold this asset group than sell it; however, if the probability associated with selling it were increased to approximately 90 percent, these assets may not be recoverable. If our recoverability estimates had resulted in a determination that these assets were not recoverable, based on our current estimates of fair value, we would have recognized an impairment loss of approximately $40 million to $70 million in the year ended December 31, 2003.

Our current estimate of recoverability for certain Canadian gas processing assets indicated that they were not recoverable due to management's expectation that these assets would be sold at a price less than their current carrying value. As a result, we recognized impairment charges of $41.7 million during 2003. We estimated fair market value using an earnings multiple applied to projected operating results. We validated this estimate of fair value with discounted future cash flows ranging from approximately $10 million above and $25 million below our estimated fair value.

CONTINGENT LIABILITIES

We record liabilities for estimated loss contingencies when we assess that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are reflected in income in the period in which new or different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Liabilities for contingent losses are based upon our assumptions and estimates, and advice of legal counsel or other third parties regarding the probable outcomes of the matter. As new developments occur or more information becomes available, it is possible that our assumptions and estimates in these matters will change. Changes in our assumptions and estimates or outcomes different from our current assumptions and estimates could materially affect future results of operations for any particular quarterly or annual period. See Note 16 of Notes to Consolidated Financial Statements.

OIL AND GAS PRODUCING ACTIVITIES

We use the successful efforts method of accounting for our oil and gas producing activities. Estimated natural gas and oil reserves and/or forward market prices for oil and gas are a significant part of our financial calculations. Following are examples of how these estimates affect financial results:

- An increase (decrease) in estimated proved oil and gas reserves can reduce (increase) our unit of production depletion rate.

- Changes in oil and gas reserves and forward market prices both impact projected future cash flows from our oil and gas properties. These projected future cash flows are used:

    - to estimate the fair value of oil and gas properties for purposes of assessing them for impairment; and

    - to estimate the fair value of the Exploration & Production reporting unit for purposes of assessing its goodwill for impairment.

- Certain estimated reserves are used as collateral to secure financing.

The process of estimating natural gas and oil reserves is very complex, requiring significant judgement in the evaluation of all available geological, geophysical, engineering and economic data. After being estimated internally, virtually all of our reserve estimates are either audited or prepared by independent experts. The data may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates could occur from time to time. A reasonably likely revision of our reserve estimates is not expected to result in an impairment of our oil and gas properties or goodwill. However, reserve estimate revisions would impact our depreciation and depletion expense prospectively. For example, a change of approximately 10 percent in oil and gas reserves for each basin would change our annual depreciation, depletion and amortization expense between approximately $15 million and $20 million. The actual impact would depend on the specific basins impacted.

Forward market prices include estimates of prices for periods that extend beyond those with quoted market prices. This forward market price information is consistent with that generally used in evaluating drilling decisions and acquisition plans. These market prices for future periods impact the production economics underlying oil and gas reserve estimates. The prices of natural gas and oil are volatile and change from period to period thus impacting our estimates. A reasonably likely unfavorable change in the forward price curve is not expected to result in an impairment of our oil and gas properties or goodwill.

GENERAL

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standard (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the consolidated financial statements and notes in Item 8 [Exhibit 99.2] reflect our results of operations, financial position and cash flows through the date of sale, as applicable, of certain components as discontinued operations (see Note 2 of Notes to Consolidated Financial Statements).

Unless indicated otherwise, the following discussion and analysis of results of operations, financial condition and liquidity relates to our current continuing operations and should be read in conjunction with the consolidated financial statements and notes thereto included in Item 8 [Exhibit 99.2] of this document.

RESULTS OF OPERATIONS

CONSOLIDATED OVERVIEW

The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2003. The results of operations by segment are discussed in further detail following this Consolidated Overview discussion.

	YEARS ENDED DECEMBER 31,				
	2003	% CHANGE FROM 2002(1)	2002	% CHANGE FROM 2001(1)	2001
	(MILLIONS)		(MILLIONS)		(MILLIONS)
Revenues	$ 16,644.7	+390%	$ 3,393.9	-31%	$ 4,899.5
Costs and expenses:					
Costs and operating expenses	14,989.7	-675%	1,934.3	+8%	2,111.2
Selling, general and administrative expenses	407.1	+28%	564.0	+14%	655.5
Other (income) expense -- net	(130.2)	NM	240.1	NM	(12.4)
General corporate expenses	87.0	+39%	142.8	-15%	124.3
Total costs and expenses	15,353.6	-433%	2,881.2	-	2,878.6
Operating income	1,291.1	+152%	512.7	-75%	2,020.9
Interest accrued -- net	(1,240.6)	-10%	(1,132.1)	-73%	(654.9)
Investing income (loss)	73.1	NM	(113.2)	+34%	(172.6)
Interest rate swap loss	(2.2)	+98%	(124.2)	NM	-
Minority interest in income and preferred returns of consolidated subsidiaries	(19.4)	+54%	(41.8)	+42%	(71.7)
Other income (expense) -- net	(26.1)	NM	24.3	-8%	26.4
Income (loss) from continuing operations before income taxes	75.9	NM	(874.3)	NM	1,148.1
(Provision) benefit for income taxes	(47.7)	NM	277.2	NM	(507.6)
Income (loss) from continuing operations	28.2	NM	(597.1)	NM	640.5
Income (loss) from discontinued operations	240.9	NM	(157.6)	+86%	(1,118.2)
Net income (loss) before cumulative effect of change in accounting principle	269.1	NM	(754.7)	-58%	(477.7)
Cumulative effect of change in accounting principles	(761.3)	NM	-	NM	-
Net loss	(492.2)	+35%	(754.7)	-58%	(477.7)
Preferred stock dividends	29.5	+67%	90.1	NM	-
Loss applicable to common stock	$ (521.7)	+38%	$ (844.8)	-77%	$ (477.7)

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(1) + = Favorable Change; - = Unfavorable Change

NM = A percentage calculation is not meaningful due to change in signs or a zero-value denominator.

2003 vs. 2002

Our revenue increased $13.3 billion due primarily to increased revenues at our Williams Power Company segment (Power) and our Midstream Gas and Liquids segment (Midstream) as a result of the January 1, 2003 adoption of EITF 02-3, which requires that revenues and costs of sale from non-derivative contracts and certain physically settled derivative contracts be reported on a gross basis (see Note 1 of Notes to Consolidated Financial Statements for a discussion of the impact on our financial statements as a result of applying this consensus). Prior to the adoption of EITF 02-3, revenues and costs of sales related to non-derivative contracts and certain physically settled derivative contracts were reported in revenues on a net basis. As permitted by EITF 02-3, prior year amounts have not been restated. Power's external revenues increased $11.5 billion and Midstream's external revenues increased $1.6 billion due primarily to the effect of EITF 02-3. The increase in revenues also includes $220 million due primarily to higher natural gas liquids (NGL) revenues at our Midstream segment's gas processing plants as a result of moderate market price increases, partially offset by lower NGL production volumes.

Results for 2003 include approximately $117 million of revenue related to the correction of the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001. This matter was initially disclosed in our Form 10-Q for the second quarter of 2003. Income from continuing operations before income taxes and cumulative effect of change in accounting principles in 2003 was $51.6 million. Absent the corrections, we would have reported a pretax loss from continuing operations in 2003. Approximately $83 million of this revenue relates to a correction of net energy trading assets for certain derivative contract terminations occurring in 2001. The remaining $34 million relates to net gains on certain other derivative contracts entered into in 2002 and 2001 that we now believe should not have been deferred as a component of other comprehensive income due to the incorrect designation of these contracts as cash flow hedges. Our management, after consultation with our independent auditor, concluded that the effect of the previous accounting treatment was not material to 2003 and prior periods and the trend of earnings.

Costs and operating expenses increased $12.9 billion due primarily to the effect of reporting certain costs gross at Power and Midstream, as discussed above. Costs increased $12.9 billion at Power and $1.8 billion at Midstream due primarily to the effect of EITF 02-3. Contributing to the increase at our Midstream segment is $113 million attributable to rising market prices for natural gas used to replace the heating value of NGLs extracted at their gas processing facilities. The cost increases at these operating units were partially offset by $1.7 billion higher intercompany eliminations resulting primarily from intercompany costs that were previously netted in revenues prior to the adoption of EITF 02-3.

Selling, general and administrative expenses decreased $156.9 million due primarily to reduced staffing levels at Power reflective of our strategy to exit this business. Also contributing to the decrease was the absence of $22 million of costs related to an enhanced benefit early retirement option offered to certain employee groups in 2002. We expect continued declines in these costs as we continue to exit the power business and complete our planned asset sales.

Other (income) expense -- net, within operating income, in 2003 includes a $188 million gain from the sale of a Power contract, $96.7 million in net gains from the sale of our Exploration & Production segment's interests in certain natural gas properties in the San Juan basin, a $16.2 million gain from Midstream's sale of the wholesale propane business, and a $12.2 million gain on foreign currency exchange at Power. Partially offsetting these gains was a $45 million goodwill impairment at Power, a $44.1 million impairment of the Hazelton generation plant at Power, a $25.6 million charge to write-off capitalized software development costs at Northwest Pipeline, a $20 million charge related to a settlement by Power with the Commodity Futures Trading Commission (see Note 16 of Notes to Consolidated Financial Statements) and a $19.5 million accrual at Power related to an adjustment of California rate refund and other related accruals. Other (income) expense -- net, within operating income, in 2002 includes $244.6 million of impairment charges, loss accruals, and write-offs within Power, including a partial impairment of goodwill, $141.7 million in net gains from the sale of Exploration & Production's interests in natural gas properties and $78.2 million of impairment charges related to Midstream's Canadian olefin assets.

General corporate expenses decreased $55.8 million. During 2002, we incurred $24 million of various restructuring costs associated with the liquidity and business issues addressed beginning third-quarter 2002. We also incurred $19 million higher advertising and branding costs in 2002 (due primarily to golf events and other advertising campaigns that were not continued in 2003). In 2004, we will continue efforts to further reduce our corporate cost structure following the recent and anticipated divestitures. We could also experience additional decreases in costs related to our health care plan for retirees as a result of the passage of the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

Interest accrued -- net increased $108.5 million, or 10 percent, due primarily to:

- $48.1 million higher interest expense and fees primarily related to the RMT note payable, which was prepaid in May 2003 (see Note 11 of Notes to Consolidated Financial Statements);

- an $18.2 million increase in capitalized interest, which offsets interest accrued, due primarily to Midstream's projects in the Gulf Coast Region;

- $25 million higher amortization expense related to deferred debt issuance costs including a $14.5 million write-off of accelerated amortization of costs from the termination of a revolving credit agreement in June 2003 (see Note 11 of Notes to Consolidated Financial Statements);

- a $43 million increase reflecting higher average interest rates on long-term debt;

- a $15 million decrease reflecting lower average borrowing levels; and

- $14.3 million of interest expense of Power as a result of certain 2003 FERC proceedings.

We expect interest expense to decrease in 2004 due to reduced averaged borrowing levels and lower average interest rates.

In 2002, we began entering into interest rate swaps with external counter parties primarily in support of the energy-trading portfolio (see Note 19 of Notes to Consolidated Financial Statements). The change in market value of these swaps was $122 million more favorable in 2003 than 2002, due largely to a reduction in overall swap positions during the second half of 2002. The total notional amount of these swaps is approximately $300 million at December 31, 2003.

Investing income increased to $73.1 million in 2003 compared to a $113.2 million loss in 2002. As detailed in Note 3 of Notes to Consolidated Financial Statements, investing income (loss) in 2003 includes:

- $52.1 million lower equity earnings from Gulfstream Natural Gas System LLC, primarily resulting from the absence in 2003 of a $27.4 million contractual construction completion fee received in 2002;

- $33.6 million higher net interest income at Power as a result of certain 2003 FERC proceedings; and

- a $43.1 million impairment related to our investment in Longhorn Partners Pipeline L.P.

Investing income (loss) in 2002 includes a $268.7 million loss provision relating to the estimated recoverability of receivables from WilTel Communications Group, Inc. (WilTel), a former subsidiary, partially offset by equity earnings and a $58.5 million gain on the sale of all of our interest in a Lithuanian oil refinery, pipeline and terminal complex.

Minority interest in income and preferred returns of consolidated subsidiaries in 2003 is lower than 2002 due primarily to the absence of preferred returns totaling $25 million on the preferred interests in Castle Associates L.P., Piceance Production Holdings L.L.C., and Williams Risk Holdings L.L.C., which were modified and reclassified as debt in third-quarter 2002, and Arctic Fox, L.L.C., which was modified and reclassified as debt in April 2002. See Note 12 of Notes to Consolidated Financial Statements.

Other income -- net, below operating income, in 2003 includes debt tender and related costs of $66.8 million, which were incurred in 2003 related to the third quarter 2003 tender offers and consent solicitations (see Note 11 of Notes to Consolidated Financial Statements). We may pursue additional debt tender offers in 2004. In addition, $84.7 million of foreign currency transaction gains on a Canadian dollar denominated note receivable are included. Partially offsetting these gains were $79.8 million of derivative losses on a forward contract to fix the U.S. dollar principal cash flows from this note. In 2004, these may be less offsetting since the note receivable balance was substantially reduced in the last half of 2003.

The provision (benefit) for income taxes was unfavorable by $324.9 million due primarily to pre-tax income in 2003 as compared to a pre-tax loss in 2002. The effective income tax rate for 2003 is significantly higher than the federal statutory rate due primarily to non-deductible impairment of goodwill, non-deductible expenses, an accrual for tax contingencies, and the effect of state income taxes, somewhat offset by the tax benefit of capital losses. The effective income tax rate for 2002 is less than the federal statutory rate due primarily to the tax benefit of capital losses and the effect of state income taxes, somewhat offset by the effect of taxes on foreign operations, non-deductible impairment of goodwill, an accrual for tax contingencies, and income tax credit recapture that reduced the tax benefit of the pre-tax loss.

In addition to the operating results from activities included in discontinued operations (see Note 2 of Notes to Consolidated Financial Statements), the 2003 loss from discontinued operations includes pre-tax gains and losses on sales, net of impairments, totaling $169.0 million. The $169.0 million consists primarily of the following:

- a $310.8 million gain on sale of Williams Energy Partners;
- a $92.1 million gain on sale of Canadian liquids operations;
- a $39.7 million gain on sale of natural gas properties in the Raton Basin in southern Colorado and the Hugoton Embayment in southwestern Kansas;
- a $108.7 million impairment of Gulf Liquids;
- a $106.2 million impairment (net of a $2.8 million gain on sale) of Texas Gas Transmission;
- a $41.7 million impairment on the Canadian straddle plants; and
- a $21.6 million loss on sale and impairment on assets of the soda ash mining facility located in Colorado.

The 2002 loss from discontinued operations includes pre-tax impairments and losses totaling $567.8 million (see the 2002 vs. 2001 discussion below).

The cumulative effect of change in accounting principles reduces net income for 2003 by $761.3 million due to a $762.5 million charge related to the adoption of EITF 02-3 (see Note 1 of Notes to Consolidated Financial Statements), slightly offset by $1.2 million related to the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" (see Note 1 of Notes to Consolidated Financial Statements).

In June 2003, we redeemed all of our outstanding 9.875 percent cumulative-convertible preferred shares for approximately $289 million, plus $5.3 million for accrued dividends (see Note 13 of Notes to Consolidated Financial Statements). Preferred stock dividends in 2002 reflects the first-quarter 2002 impact of recording a $69.4 million non-cash dividend associated with the accounting for a preferred security that contained a conversion option that was beneficial to the purchaser at the time the security was issued.

2002 vs. 2001

Our revenue decreased approximately $1.5 billion, or 31 percent, due primarily to lower revenues associated with energy risk management and trading activities at Power and the absence of $184 million of revenue related to the 198 convenience stores sold in May 2001 within our previously reported Petroleum Services segment (Petroleum Services). Partially offsetting these decreases was the impact of an increase in net production volumes within Exploration & Production partly due to the August 2001 acquisition of Barrett Resources Corporation (Barrett). As permitted by EITF 02-3, discussed above, 2002 and 2001 revenues were not restated for the adoption of EITF 02-3 in January 2003.

Costs and operating expenses decreased $176.9 million, or 8 percent, due primarily to the absence of the 198 convenience stores sold in May 2001. Slightly offsetting these decreases are increased depletion, depreciation and amortization and lease operating expenses at Exploration & Production due primarily to the addition of the former Barrett operations.

Selling, general and administrative expenses decreased $91.5 million due primarily to lower variable compensation levels at Power. Selling, general and administrative expenses for 2002 also include approximately $22 million of early retirement costs, $9 million of employee-related severance costs and approximately $5 million related to early payoff of employee stock ownership plan expenses.

Other (income) expense -- net, within operating income, in 2002 includes $244.6 million of impairment charges and loss accruals within Power comprised of $138.8 million of impairments and loss accruals for commitments for certain power assets associated with terminated power projects, $61.1 million goodwill impairments and a $44.7 million impairment charge related to the Worthington generation facility sold in January 2003. Included in Other (income) expense -- net, within operating income, in 2002 is a $78.2 million impairment charge related to Midstream's Canadian olefin assets. Partially offsetting these impairment charges and accruals are $141.7 million of net gains on sales of natural gas production properties at Exploration & Production in 2002. Other (income) expense -- net, within operating income, in 2001 includes a $75.3 million gain on the May 2001 sale of the convenience stores and impairment charges of $13.8 million and $12.1 million within Midstream and the former Petroleum Services segment, respectively (see Note 4 of Notes to Consolidated Financial Statements).

General corporate expenses increased $18.5 million, or 15 percent, due primarily to approximately $24 million of various restructuring costs associated with the liquidity and business issues addressed beginning third-quarter 2002, $6 million of expense related to the enhanced-benefit early retirement program offered to certain employee groups and $6 million of expense related to employee severance costs. Partially offsetting these increases were lower charitable contributions and advertising costs.

Operating income decreased $1,508.2 million, or 75 percent, due primarily to lower net revenues associated with energy risk management and trading activities at Power and the impairment charges and loss accruals noted above. Partially offsetting these decreases are the gains from the sales of natural gas production properties and the impact of increased net production volumes at Exploration & Production, higher demand revenues and the effect of the reductions in rate refund liabilities associated with rate case settlements at Gas Pipeline, and higher equity earnings.

Interest accrued -- net increased $477.2 million, or 73 percent, due primarily to $154 million related to interest expense, including amortization of fees, on the RMT note payable (see Note 11 of Notes to Consolidated Financial Statements), the $76 million effect of higher average interest rates, the $222 million effect of higher average borrowing levels and $41 million of higher debt issuance cost amortization expense.

In 2002, we entered into interest rate swaps with external counter parties primarily in support of the energy trading portfolio. The swaps resulted in losses of $124.2 million (see Note 19 of Notes to Consolidated Financial Statements).

The 2002 investing loss decreased $59.4 million as compared to the 2001 investing loss. Investing loss for 2002 and 2001 consisted of the following components:

	YEARS ENDED DECEMBER 31 2002	2001
	(MILLIONS)	
Equity earnings*	$ 73.0	$ 22.7
Income from investments*	42.1	4.2
Write-down of WilTel common stock investment	--	(95.9)
Loss provision for WilTel receivables	(268.7)	(188.0)
Interest income and other	40.4	84.4
Investing loss	$ (113.2)	$ (172.6)

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* These items are also included in the measure of segment profit (loss).

The equity earnings increase includes a $27.4 million benefit reflecting a contractual construction completion fee received by an equity method investment (see Note 3 of Notes to Consolidated Financial Statements) and $4 million of earnings in 2002 versus $20 million of losses in 2001 from the Discovery pipeline project, partially offset by an equity loss in 2002 of $13.8 million from our investment in Longhorn Partners Pipeline LP. Income (loss) from investments in 2002 includes a $58.5 million gain on the sale of our equity interest in a Lithuanian oil refinery, pipeline and terminal complex, which was included in the Other segment, a gain of $8.7 million related to the sale of our general partner interest in Northern Borders Partners, L.P., a $12.3 million write-down of an investment in a pipeline project which was canceled and a $10.4 million net loss on the sale of our equity interest in a Canadian and U.S. gas pipeline. Income (loss) from investments in 2001 includes a $27.5 million gain on the sale of our limited partner equity interest in Northern Border Partners, L.P. offset by a $23.3 million loss from other investments, both of which were determined to be other than temporary. See Note 2 of Notes to Consolidated Financial Statements for a discussion of the losses related to WilTel. Interest income and other decreased due to a $22 million decrease in interest income related to margin deposits, a $4.9 million decrease in dividend income primarily as a result of the second-quarter 2001 sale of Ferrellgas Partners L.P. senior common units and write-downs of certain foreign investments.

Other income (expense) -- net, below operating income, decreased $2.1 million due primarily to an $11 million gain in second-quarter 2002 at our Gas Pipeline segment associated with the disposition of securities received through a mutual insurance company reorganization, a $13 million decrease in losses from the sales of receivables to special purpose entities (see Note 15 of Notes to Consolidated Financial Statements) and the absence in 2002 of a 2001 $10 million payment to settle a claim for coal royalty payments relating to a discontinued activity. Partially offsetting these increases was an $8 million loss related to early retirement of remarketable notes in first-quarter 2002.

The provision (benefit) for income taxes was favorable by $784.8 million due primarily to a pre-tax loss in 2002 as compared to pre-tax income in 2001. The effective income tax rate for 2002 is less than the federal statutory rate due primarily to the tax benefit of capital losses and the effect of state income taxes, somewhat offset by the effect of taxes on foreign operations, non-deductible impairment of goodwill, an accrual for tax contingencies, and income tax credits recapture that reduced the tax benefit of the pre-tax loss. The effective income tax rate for 2001 is greater than the federal statutory rate due primarily to an accrual for tax contingencies, the effect of state income taxes, and valuation allowances associated with the tax benefits for investing losses, for which no tax benefits were provided.

In addition to the operating results from activities included in discontinued operations (see Note 2 of Notes to Consolidated Financial Statements), the 2002 loss from discontinued operations includes pre-tax impairments and losses totaling $567.8 million. The $567.8 million consists of $240.8 million of impairments related to the Memphis refinery, $195.7 million of impairments related to bio-energy, $146.6 million of impairments related to travel centers, $133.5 million of impairments related to the soda ash operations, a $91.3 million loss on sale related to the Central natural gas pipeline system, a $36.8 million impairment related to the Canadian straddle plants, $18.4 million of impairments related to the Alaska refinery and a $6.4 million loss on sale related to the Kern River natural gas pipeline system. Partially offsetting these impairments and losses was a pre-tax gain of $301.7 million related to the sale of the Mid-America and Seminole pipelines. Loss from discontinued operations in 2001 includes a $1.84 billion pre-tax charge for loss accruals related to guarantees and payment obligations for WilTel and $184.8 million of other pre-tax charges for impairments and loss accruals, including a $170 million pre-tax impairment charge related to the soda ash mining facility.

Income (loss) applicable to common stock in 2002 reflects the impact of the $69.4 million associated with accounting for a preferred security that contains a conversion option that was beneficial to the purchaser at the time the security was issued. The weighted-average number of shares in 2002 for the diluted calculation (which is the same as the basic calculation since we reported a loss from continuing operations) increased approximately 16 million from December 31, 2001. The increase is due primarily to the 29.6 million shares issued in the Barrett acquisition in August 2001.

RESULTS OF OPERATIONS -- SEGMENTS

We are currently organized into the following segments: Power (formerly named Energy Marketing & Trading), Gas Pipeline, Exploration & Production, Midstream and Other. The Petroleum Services segment is now reported within Other as a result of the Alaska refinery and related assets being reflected as discontinued operations. Other primarily consists of corporate operations and certain continuing operations previously reported within the International and Petroleum Services segments. Our management currently evaluates performance based on segment profit (loss) from operations (see Note 19 of Notes to Consolidated Financial Statements).

Prior period amounts have been restated to reflect these changes. The following discussions relate to the results of operations of our segments.

POWER

OVERVIEW OF 2003

As described below, a strategic change in business focus and a required change in accounting principles significantly influenced Power's 2003 operating results.

In June 2002, we announced our intent to exit our Power business and reduce our financial commitment to the Power segment. Prior to this point, Power focused on originating short-term and long-term contracts that it considered profitable based on its view of the market. Beginning in mid-2002, Power now focuses on 1) terminating or selling all or portions of the portfolio, 2) maximizing cash flow, 3) reducing risk, and 4) managing existing contractual commitments, many of which are long-term. We initiated efforts to sell all or portions of Power's power, natural gas, and crude and refined products portfolios in mid-2002. Based on bids received in these sales efforts, Power recognized impairments for certain assets and capital projects in 2002. In 2003, we continued our efforts to exit this business. In 2003, proceeds from contract sales and terminations exceeded carrying values, resulting in gains. The decision to exit the Power business also resulted in decreased selling, general and administrative expense. Segment profit was unfavorably impacted in 2003 as a result of reduced origination of long-term energy-related transactions.

As discussed further in Note 1 of Notes to the Consolidated Financial Statements, in 2003, Power adopted EITF 02-3, which changed the classification of certain revenues and costs in the statement of operations and the accounting method for non-derivative energy and energy-related contracts. Decreased power prices and increased natural gas prices primarily caused an increase in the fair value of power and gas derivative contracts, which is reflected as an increase in earnings. Due to the change in accounting method discussed further below, the related change in fair value of non-derivative contracts was not recognized in earnings during 2003 since non-derivative contracts are no longer marked to market. However, accrual losses on power and gas non-derivative contracts were recognized in 2003.

Power considers key factors that influence its financial condition and operating performance to include the following:

- prices of power and natural gas, including changes in the margin between power and natural gas prices,
- changes in market liquidity, including changes in the ability to economically hedge the portfolio,
- changes in power and natural gas price volatility,
- changes in the regulatory environment, and
- changes in power and natural gas supply and demand.

OUTLOOK FOR 2004

In 2004, Power anticipates further variability in earnings due in part to the difference in accounting treatment of derivative contracts at fair value and our underlying non-derivative contracts on an accrual basis. This difference in accounting treatment combined with the volatile nature of energy commodity markets could result in future operating gains or losses. Some of Power's tolling contracts have a negative fair value, which is not reflected in the financial statements since these contracts are not derivatives. These tolling contracts may result in future accrual losses. Continued efforts to sell all or a portion of the portfolio may also have a significant impact on future earnings as proceeds may differ significantly from carrying values. The inability of counterparties to perform under contractual obligations due to their own credit constraints could also affect future operations.

The following risks and challenges also impact how Power manages its business and affect its operating results:

- unresolved litigation,
- regulatory changes and oversight,
- lack of liquidity, and
- key employee retention.

YEAR-OVER-YEAR OPERATING RESULTS

	YEARS ENDED DECEMBER 31, 2003	2002	2001
	(MILLIONS)		
Segment revenues.......	$ 13,192.6	$ (85.2)	$ 1,705.6
Segment profit (loss)..	$ 135.1	$ (626.2)	$ 1,265.1

2003 vs. 2002

INCREASE IN REVENUES AND COST OF SALES

EITF 02-3 impacts how Power presents revenues and costs from certain transactions in the statement of operations. The table below summarizes items included in revenues and costs before and after January 1, 2003:

BEFORE	AFTER
Revenues:	Revenues:
- Gains and losses from changes in fair value of all energy trading contracts with a future settlement or delivery date and from changes in fair value of commodity inventories	- Gains and losses from changes in fair value of only derivative contracts with a future settlement or delivery date
- Revenue from sales of commodities or completion of energy-related services	- Revenue from sales of commodities or completion of energy-related services
- Gains and losses from net financial settlement of derivative contracts	- Gains and losses from net financial settlement of derivative contracts
- Costs from purchases of commodities or fees from energy-related services that were not associated with property, plant and equipment we owned	
Costs:	Cost:
- Costs from purchases of commodities or fees for energy-related services for use in property, plant and equipment that we owned	- Costs from purchases of all commodities and fees paid for energy-related services

Revenues increased $13.3 billion and costs increased $12.9 billion from 2002 to 2003 primarily because Power now reports certain purchases in costs instead of reporting them as reduction of revenues. This change in reporting does not affect gross margin or segment profit. EITF 02-3 does not require restatement of prior year amounts. As presented in the table that follows this section, Power also now accounts for a significant portion of its business activity using the accrual method of accounting rather than recognizing changes in fair value through segment profit, or mark-to-market accounting.

INCREASE IN SEGMENT PROFIT

EITF 02-3, which was implemented January 1, 2003, significantly impacted the increase in segment profit from 2002 to 2003. Before the adoption of EITF 02-3, Power reported the fair value of all its energy contracts, energy-related contracts and inventory on the balance sheet. Power reported changes in the fair value of the items from period to period in segment profit. Examples of derivative and non-derivative contracts are as follows:

DERIVATIVE CONTRACTS	NON-DERIVATIVE CONTRACTS
- Forward purchase and sale contracts	- Spot purchase and sale contracts
- Futures contracts	- Transportation contracts
- Option contracts	- Storage contracts
- Swap agreements	- Tolling agreements (power conversion contracts)
	- Full requirement or load serving contracts (power sales contracts in which we supply all of the customer's requirements for power)

In 2003, Power continues to reflect the changes in fair value of derivative contracts in segment profit. However, for non-derivative contracts, Power does not recognize revenue until commodities are delivered or services are completed. Also, for non-derivative contracts, Power does not recognize costs until products are received and consumed, services are used, or inventories are sold. Power is exposed to earnings fluctuations because of these differences in accounting for derivative and non-derivative contracts within its portfolio. The following example illustrates this exposure to earnings fluctuations:

> Assume there are two contracts. The first is a ten-year contract in which Power agrees to pay a counterparty a monthly fee for the right to convert natural gas to power (a tolling contract). Power has the right to sell the power produced under the tolling contract. The contract is not a derivative. The second is a derivative contract to sell power in 2008 to another party for a fixed price, entered into to fix the sales price of the power produced in 2008 under the tolling contract. Therefore, the power sales contract economically hedges the forward power price component of the tolling contract. If power prices fall, the decline in fair value of the tolling agreement would not be reflected in 2003 segment profit since the contract is not a derivative. The increase in the fair value of the power sale contract, however, would be reflected in segment profit since it is a derivative.

As illustrated in the above example, many of our derivative contracts serve as economic hedges of our non-derivative positions. We could reduce our exposure to earnings fluctuations by applying hedge accounting, as provided for under SFAS No. 133. However, since we have announced our intent to exit the business, we do not currently meet the criteria to be eligible for hedge accounting. We reduced our exposure to earnings fluctuations through election of the normal purchases and sales exception available under SFAS No. 133 for two significant long-term derivative contracts. These two derivative contracts hedge a tolling contract. Since the election in the second quarter of 2003, we account for the two derivative contracts on an accrual basis. However, we remain exposed to earnings fluctuations from changes in fair value of certain other derivative positions.

The following table summarizes the major elements impacting segment profit in 2003 and 2002:

	YEARS ENDED DECEMBER 31, 2003	2002
	(MILLIONS)	
Accrual earnings (losses)	$(268)	$ 11
Mark-to-market earnings (losses)	401	(420)
Interest rate portfolio earnings (losses)	(12)	91
Origination	--	204
Prior period adjustments	117	--
Gross margin	238	(114)
Operating expenses	35	40
Selling, general and administrative expenses	124	209
Other income (expense) -- net	56	(263)
Segment profit (loss)	$ 135	$(626)

INCREASE IN GROSS MARGIN

The impact of the earnings fluctuations discussed in the previous section is reflected in our 2003 gross margin. Gross margin increased from a margin loss of $114.2 million in 2002 to a gross margin of $238 million in 2003.

Accrual Earnings: Losses on contracts and assets in 2003 accounted for on an accrual basis partially offset increases in gross margin from mark-to-market earnings as discussed in the next section. In 2002, we accounted for revenues and costs generated only on our owned assets on an accrual basis. These owned assets resulted in a $10.9 million gross margin in 2002. In 2003, we also accounted for revenues and costs generated on our non-derivative contracts on an accrual basis. The owned assets and non-derivative contracts generated a $268.1 million margin loss in 2003.

The $268.1 million margin loss primarily consists of accrual losses of $246.6 million on non-derivative contracts and owned assets within our power and natural gas portfolios. As with forward power prices, the increased power supply in the mid-continent and eastern regions contributed to lower prices received on power sales in 2003, primarily contributing to the accrual losses. The $246.6 million also includes a $37 million loss from increased power rate refunds owed to the state of California because of FERC rulings issued and a $13.8 million loss for other contingencies related to our power marketing activities in the state of California.

Mark-to-Market Earnings: The difference in accounting for non-derivative contracts in 2003 compared to 2002 primarily contributed to the increase in gross margin. In 2002, we recognized mark-to-market losses of $420 million on derivative contracts and non-derivative contracts, both of which we carried at fair value, or marked to market, in 2002. In 2003, we recognized mark-to-market gains of $401.4 million on derivative contracts only. We refer to net realized and unrealized gains and losses on contracts carried at fair value as mark-to-market earnings.

Derivative contracts within our power and natural gas portfolios primarily contributed to the mark-to-market gains in 2003, generating $412.3 million of the total mark-to-market gains of $401.4 million. Decreased forward power prices on net power sales contracts and increased forward gas prices on net gas purchase contracts primarily caused the mark-to-market gains from power and natural gas derivative contracts. Increased power supply in the mid-continent and eastern U.S. significantly contributed to the decrease in forward power prices. A $126.8 million positive valuation adjustment on a terminated derivative contract also contributed to the 2003 mark-to-market gains on power and natural gas derivative contracts.

Of the $420 million in mark-to-market losses in 2002, $320 million related to the power and natural gas portfolios. The fair value of certain tolling portfolios decreased as the margin between forward power prices and the estimated cost to produce the power decreased. The decline in volatility of the power and natural gas markets also contributed to the decrease in the fair value of tolling contracts within certain of our tolling portfolios as it does other option contracts. Tolling contracts possess characteristics of options since we have the right but not the obligation to request the plant owner to convert natural gas to power. Valuation methods used in 2002 are discussed in Note 1 of the Notes to Consolidated Financial Statements. Power and natural gas mark-to-market losses in 2002 also reflected a $74.8 million valuation adjustment on certain non-derivative power sale contracts. Quotes received during sales efforts in 2002 resulted in the valuation adjustment. The favorable net effect of approximately $85 million resulting from a settlement with the state of California partially offsets the 2002 mark-to-market losses. The $85 million primarily reflects the increase in fair value on power sales contracts with the California Department of Water Resources, which resulted from a restructuring of the contracts and the improved credit standing of the counterparty.

Interest Rate Portfolio: Differences in the treatment of interest rate movements in 2003 compared to 2002 also offset the increase in gross margin. The 2002 interest rate earnings of $91 million reflect the impact of decreased interest rates on power, natural gas and crude and refined derivative and non-derivative contracts. As interest rates decreased, the overall fair value of these commodity contracts increased. The increase in the fair value of these contracts was partially offset by the decrease in the fair value of interest rate derivatives. Interest rate derivatives hedge the power, natural gas and crude and refined products contracts on an economic basis. The 2003 interest rate loss of $12.3 million reflects the mark-to-market loss on interest rate derivatives only.

Origination: The lack of contract origination in 2003 further offsets the increase in gross margin. Consistent with our reduced financial commitment to the Power business, we did not originate long-term energy-related contracts in 2003. In 2002, we recognized $85.1 million of power and natural gas revenues and $118.8 million of petroleum products revenues by originating new contracts.

Correction of Prior Period Items: Results for 2003 include approximately $117 million of revenue related to the correction of the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001. This matter was initially disclosed in our Form 10-Q for the second quarter of 2003. See Note 1 of Notes to Consolidated Financial Statements.

DECREASE IN SELLING, GENERAL AND ADMINISTRATIVE EXPENSES

The reduced focus on the Power business resulted in further employee reductions in 2003. Power employed approximately 250 employees at the end of 2003 compared to approximately 410 at the end of 2002. This decrease in employees was the primary factor in the $85 million, or 41 percent, decrease in selling, general, and administrative expenses.

INCREASE IN OTHER INCOME (EXPENSE) -- NET

Other income (expense) -- net improved $319.5 million. Power terminated or sold certain contracts and other assets, resulting in losses in 2002 and gains in 2003. In 2002, Power terminated certain power -- related capital projects, which resulted in $138.8 million of impairments. Power also recorded a $44.7 million impairment in 2002 from the January 2003 sale of the Worthington generation facility. In 2003, Power sold a non-derivative energy-trading contract resulting in a $188 million gain on sale. Power also sold an interest in certain investments accounted for under the cost method in 2003 for a gain of $13.8 million.

A $45 million goodwill impairment in 2003 compared to a $61.1 million goodwill impairment in 2002 also contributed to the increase in Other (income) expense-net. See Note 4 of Notes to Consolidated Financial Statements.

Other factors offset the increase in Other income (expense) -- net. In 2003, Power recognized a $44.1 million impairment on a power generating facility (see Note 4 of Notes to Consolidated Financial Statements) and $14.1 million of impairment charges associated with the Aux Sable partnership investment (see Note 3 of Notes to Consolidated Financial Statements). Power also reached a settlement with the Commodity Futures Trading Commission as discussed in Note 16 of Notes to Consolidated Financial Statements, resulting in a charge of $20 million. Finally, Power recorded accruals of $19.5 million for power marketing activities in California during 2000 and 2001 (see Note 16 of Notes to Consolidated Financial Statements).

2002 vs. 2001

The $1,790.8 million, or 105 percent, decrease in revenues is due primarily to a $1,783.3 million decrease in risk management and trading revenues. During 2002, the impact of market movements against Power's portfolio and a significant reduction in origination activities adversely affected our results. Power's ability to manage or hedge its portfolio against adverse market movements was limited by a lack of market liquidity as well as our limited ability to provide credit and liquidity support.

The decrease in risk management and trading revenues includes the following:

- $1,901.4 million decrease in natural gas and power revenues,

- $6.3 million increase in petroleum products revenues,

- $12 million increase in European trading revenues, and

- $99.8 million increase in interest rate revenues.

The net impact of interest rate movements, including the impact of interest derivatives, caused the $99.8 million increase in interest rate revenues.

The $1,783.3 million decrease in risk management and trading revenues includes a $205 million decrease in revenues from new transactions originated and contract amendments as compared to 2001. A decline in natural gas revenues caused $454.9 million of the $1,901.4 million decline in natural gas and power revenues. Increasing prices on short natural gas positions during the third quarter of 2002 primarily caused the decline in natural gas revenues. The remaining $1,446.5 million decline in natural gas and power revenues relates to lower revenues from the power portfolio caused primarily by 1) smaller differences in the margin between forward power prices and the estimated cost to produce the power on certain power tolling portfolios; 2) lower volatility compared with 2001; and 3) the net impact of portfolio valuation adjustments associated with the decline in market liquidity and portfolio liquidation activities.

Origination activities during the first quarter of 2002 primarily caused the $6.3 million increase in petroleum products revenues. The commencement of trading activities in the European office as compared to start-up activities in 2001 principally drove the $12 million increase in European trading revenues. The European operations were being wound down in 2002.

As a result of our liquidity constraints, we initiated efforts in 2002 to sell all or portions of Power's portfolio and/or pursue potential joint venture or business combination opportunities. Portions of Power's portfolio were recognized at their estimated fair value, which under generally accepted accounting principles is the amount at which they could be exchanged in a current transaction between willing parties other than in a forced liquidation or sale. As a result of information obtained through the portfolio sales efforts in 2002, Power adjusted the estimated fair value of certain portions of the portfolio to reflect viable market information received. For those portions of the portfolio for which no viable market information was received through sales efforts, Power estimated fair value using other market-based information and consistent application of valuation techniques. Portfolio valuation adjustments recognized in 2002 as a result of new market information obtained through sales efforts resulted in a $74.8 million decrease in segment profit.

Revenues for 2002 also includes the favorable fourth-quarter net effect of approximately $85 million resulting from the settlement with the state of California, the restructuring of associated energy contracts, and the related improved credit situation of the counterparties during the quarter.

Selling, general, and administrative expenses decreased by $124.7 million, or 37 percent. Lower variable compensation levels and staff reductions primarily caused this cost reduction.

Other (income) expense -- net in 2002 includes the following:

- Impairments and loss accruals associated with commitments for certain power projects that have been terminated of $138.8 million;

- Partial impairment of goodwill of $61.1 million, reflecting a decline in fair value resulting from deteriorating market conditions during 2002; and

- Impairment charge related to the January 2003 sale of the Worthington generation facility of $44.7 million.

Other (income) expense -- net in 2001 included a $13.3 million charge due to a terminated expansion project.

The $1,891.3 million, or 149 percent decrease in Segment profit (loss) is due primarily to the $1,783.3 million reduction of risk management and trading revenues and the other (income) expense -- net items, partially offset by the $124.7 million reduction in selling, general and administrative expenses, and the $23.3 million charge from the write-downs in 2001 of marketable equity securities and a cost based investment (see Note 3 of Notes to Consolidated Financial Statements).

GAS PIPELINE

OVERVIEW OF 2003

Gas Pipeline's interstate transmission and storage activities are subject to regulation by the FERC and as such, our rates and charges for the transportation of natural gas in interstate commerce, and the extension, enlargement or abandonment of jurisdictional facilities and accounting, among other things, are subject to regulation. The rates are established through the FERC's rulemaking process. As a result of this regulation, Gas Pipeline's revenues and operating costs are relatively stable, with fluctuations primarily driven by the approval by the FERC of new rates, the level of pipeline transportation capacity used and seasonal demands. Therefore capacity is a significant factor for revenues and ultimately segment profit.

During 2003, Gas Pipeline completed five major expansion projects. The combined impact of the completed projects resulted in the following:

Northwest Pipeline:

- Created 450,000 Dth/d of new physical capacity.

- Installed more than 120 miles of new pipeline looping in Washington, Idaho, and Wyoming.

Transco:

- Increased capacity by 320,000 Dth/d.

- Installed more than 43 miles of new pipeline.

Significant risk factors that could affect the profitability of our Gas Pipeline segment include:

- legal and regulatory events such as FERC rate authorization and/or rate case settlements (see Note 16 of Notes to Consolidated Financial Statements),

- market demand for expansion projects to increase revenue and segment profit, and

- catastrophic events to our infrastructure such as ruptures to pipelines.

OUTLOOK FOR 2004

In December 2003, we received an order from the U.S. Department of Transportation regarding restoration of transportation service on a segment of a natural gas pipeline in western Washington. The pipeline experienced a line break in May 2003 and we subsequently received an order to lower pressure by 20 percent and perform an integrity study on the pipeline segment. The pipeline experienced a second break in the same segment in December 2003. In December, we idled the pipeline segment until its integrity could be assured. The decision to idle the pipeline has not had a significant impact on our ability to meet market demand, primarily because we have a parallel pipeline in the same corridor. We have, thus far, been able to meet customers' demand including peak loads during January 2004. But, during the non-peak demands of spring and summer when gas on gas competition can be strong, customers may have to take gas from other than preferred sources. If we are unable to meet customers' demand, then we may have to reduce our billings to them. The future costs to first restore portions of the existing pipeline to temporary service and then to replace the pipeline's capacity entirely are expected to be in the range of approximately $365 million to $430 million over a three-year period, the majority of which will be spent in 2005 and 2006. We expect to have adequate financial resources to comply with the order and replace the capacity, if required.

In February 2004, Gas Pipeline placed a pipeline expansion into service increasing capacity on its Transco natural gas system by 54,000 Dth/d. The completed projects for Northwest Pipeline and Transco are expected to increase revenues in 2004 by approximately $45 million. The majority of the planned 2004 capital expenditures is expected to be spent on maintenance of the pipelines.

YEAR-OVER-YEAR OPERATING RESULTS

During 2003, we sold Texas Gas Transmission Corporation (Texas Gas). We received $795 million in cash and the buyer assumed $250 million in debt. During 2002, we sold both our Central and Kern River interstate natural gas pipeline businesses. The following discussions exclude any gains or losses on such sales and the results of operations related to Texas Gas, Central, and Kern River, which are all reported within discontinued operations.

The following discussions relate to the current continuing businesses of our Gas Pipeline segment which includes Transco, Northwest Pipeline and various joint venture projects. Certain assets sold during 2002 are included in the 2002 results. These assets include Cove Point, a general partner interest in Northern Border, and our 14.6 percent interest in Alliance Pipeline. These assets represented $7.4 million of revenues and $15.7 million of segment profit for the year ended December 31, 2002.

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
		(MILLIONS)	
Segment revenues.......	$1,368.3	$1,301.2	$1,243.1
Segment profit.........	$ 555.5	$ 535.8	$ 463.8

2003 vs. 2002

The $67.1 million, or five percent, increase in revenues is due primarily to $61 million higher demand revenues on the Transco system resulting from new expansion projects (MarketLink, Momentum and Sundance) and higher rates approved under Transco's rate proceedings that became effective in late 2002 and $27 million on the Northwest Pipeline system resulting from new projects (Gray's Harbor, Centralia, and Chehalis). Revenue also increased due to $10 million higher gathering revenue on Transco. Partially offsetting these increases was the absence in 2003 of $26 million of revenue from reductions in the rate refund liabilities and other adjustments associated with a rate case settlement on Transco in 2002 and $13 million lower storage demand revenues in 2003 due to lower storage rates in connection with Transco's rate proceedings that became effective in late 2002.

Cost and operating expenses increased $21 million, or three percent, due primarily to $25 million higher depreciation expense due to additional property, plant and equipment placed into service and $12 million higher state sales and use, ad valorem and franchise taxes. These increases were partially offset by $15 million lower fuel expense on Transco, resulting primarily from pricing differentials on the volumes of gas used in operation. Costs and operating expenses are projected to be approximately $20 million higher in 2004 due primarily to non-capitalized maintenance projects.

General and administrative costs decreased $32 million, or 20 percent, due primarily to the absence in 2003 of $23 million of early retirement pension costs recorded in 2002 and other employee-related benefits costs associated with reduced employee levels as well as the absence of a $5 million write-off in 2002 of capitalized software development costs resulting from cancellation of a project. General and administrative costs in 2004 are projected to be consistent with 2003 amounts.

Other (income) expense -- net in 2003 includes a $25.6 million charge at Northwest Pipeline to write-off capitalized software development costs for a service delivery system. Subsequent to the implementation of the same system at Transco in the second quarter of 2003 and a determination of the unique and additional programming requirements that would be needed to complete the system at Northwest Pipeline, management determined that the system would not be implemented at Northwest Pipeline. Other (income) expense -- net in 2003 also includes $7.2 million of income at Transco due to a partial reduction of accrued liabilities for claims associated with certain producers as a result of recent settlements and court rulings. Other income (expense) -- net in 2002 includes a $17 million charge associated with a FERC penalty (see Note 16 of Notes to Consolidated Financial Statements) and a $3.7 million loss on the sale of the Cove Point facility.

SUMMARIZED CHANGES IN GAS PIPELINE'S SEGMENT PROFIT:

Segment profit, which includes equity earnings and income (loss) from investments (included in Investing income (loss)), increased $19.7 million, or four percent, due to the following favorable 2003 items:

- the $67.1 million increase in revenues,
- the $32 million decrease in general and administrative costs,
- the absence of the $17 million FERC charge in 2002 discussed above; and
- the absence of the $12.3 million write off of Gas Pipeline's investment in a cancelled pipeline project and a $10.4 million loss on the sale of Gas Pipeline's 14.6 percent ownership interest in Alliance Pipeline in 2002. Both items were included in income (loss) from investment, which is included in Investing income (loss).

These increases to segment profit were partially offset by the following:

- $73 million lower equity earnings (included in Investing income (loss)),
- the $25.6 million charge at Northwest Pipeline to write-off capitalized software costs discussed previously,
- the $21 million higher operating costs, and
- the absence of an $8.7 million gain in 2002 on the sale of our general partnership interest in Northern Border Partners, L.P.

The $73 million decrease to equity earnings reflects $24 million lower equity earnings from Gulfstream, the absence of a $27.4 million benefit in 2002 related to the contractual construction completion fee received by an equity affiliate and the absence of $19 million of equity earnings following the October 2002 sale of Gas Pipeline's 14.6 percent ownership in Alliance Pipeline. The lower earnings for Gulfstream were primarily due to the absence in 2003 of interest capitalized on internally generated funds as allowed by the FERC during construction. The Gulfstream pipeline was placed into service during second-quarter 2002.

2002 vs. 2001

The $58.1 million, or five percent, increase in revenues is due primarily to $67 million higher demand revenues on the Transco system resulting from new expansion projects and new settlement rates effective September 1, 2001 and $10 million impact of reductions in the rate refund liabilities associated with rate case settlements on the Transco system. Revenue also increased due to $8 million higher transportation revenue on the Northwest Pipeline system, $9 million from environmental mitigation credit sales and services and $4 million higher revenues associated with tracked costs, which are passed through to customers (offset in general and administrative expenses). Partially offsetting these increases were $23 million lower gas exchange imbalance settlements (offset in costs and operating expenses), $14 million lower storage revenues and $7 million lower revenues associated with the recovery of tracked costs which are passed through to customers (offset in costs and operating expenses). The decrease in storage revenues noted above is primarily due to $9 million lower rates on Cove Point's short term storage contracts (the Cove Point facility was sold in September 2002) and a $6 million decrease at Transco due primarily to lower storage demand.

Costs and operating expenses decreased $32 million, or five percent, due primarily to $23 million lower gas exchange imbalance settlements (offset in revenues), $19 million lower operations and maintenance expense due primarily to lower professional and other contractual services and telecommunications expenses, $7 million lower other tracked costs which are passed through to customers (offset in revenues) and a $5 million franchise tax refund for Transco. These decreases were partially offset by the $15 million effect in 2001 of a regulatory reserve reversal resulting from the FERC's approval for recovery of fuel costs incurred in prior periods by Transco, as well as $13 million higher depreciation expense. The $13 million higher depreciation expense reflects a $15 million increase due to increased property, plant and equipment placed into service (including depletion of property held for the environmental mitigation credit sales), partially offset by a $2 million adjustment related to the 2002 rate case settlements resulting in lower depreciation rates applied retroactively.

General and administrative costs increased $17 million, or 12 percent, due primarily to $10 million higher employee-related benefits expense, including:

- $8 million related to higher pension and retiree medical expense due to decreases in assumed return on plan assets, and

- approximately $3 million related to expense recognized as a result of accelerated company contributions to an employee stock ownership plan.

Also contributing to the increase is $11 million in costs associated with an early retirement program, a $5 million write-off in 2002 of capitalized software development costs resulting from cancellation of a project, and $4 million higher tracked costs (offset in revenues). These increases were partially offset by $12 million lower charitable contributions in 2002.

Other income (expense) -- net in 2002 includes a $17 million charge associated with a FERC penalty (see Note 16 of Notes to Consolidated Financial Statements) and a $3.7 million loss on the sale of the Cove Point facility. Other (income) expense -- net in 2001 includes an $18 million charge resulting from the unfavorable court decision and resulting settlement in one of Transco's royalty claims proceedings (an additional $19 million is included in interest expense).

SUMMARIZED CHANGES IN GAS PIPELINE'S SEGMENT PROFIT

Segment profit, which includes equity earnings and income (loss) from investments (both included in Investing income (loss)), increased $72 million, or 16 percent, due primarily to the following:

- $67 million higher demand revenues discussed above,
- $42.1 million higher equity earnings (included in Investing income (loss)),
- $32 million lower costs and operating expenses discussed above,
- the effect of the $18 million 2001 charge discussed previously in Other (income) expense -- net,
- the $10 million effect of rate refund liability reductions related to the finalization of rate cases during third-quarter 2002, and
- an $8.7 million gain in 2002 on the sale of our general partnership interest in Northern Border Partners, L.P.

These increases were partially offset by the following items:

- the effect of a $27.5 million gain in 2001 from the sale of our limited partnership interest in Northern Border Partners, L.P.,
- the $17 million increase in general and administrative costs discussed above,
- the $17 million FERC penalty and the $3.7 million loss on the sale of the Cove Point facility discussed above in Other income (expense),
- a $12.3 million write-down in 2002 of Gas Pipeline's investment in a cancelled pipeline project, and
- a loss of $10.4 million on the sale of Gas Pipeline's 14.6 percent ownership interest in Alliance Pipeline.

The $42.1 million increase in equity earnings includes a $27.4 million benefit in 2002 related to the contractual construction completion fee received by an equity affiliate. This equity affiliate served as the general contractor on the Gulfstream pipeline project for Gulfstream Natural Gas System (Gulfstream), an interstate natural gas pipeline subject to FERC regulation and an equity affiliate. The fee, paid by Gulfstream and associated with the completion during the second quarter of 2002 of the construction of Gulfstream's pipeline, was capitalized by Gulfstream as property, plant and equipment and is included in Gulfstream's rate base to be recovered in future revenues. Additionally, the increase in equity earnings reflects an $18 million increase from Gulfstream, $12 million of which is related to interest capitalized on the Gulfstream pipeline project in accordance with FERC regulations.

EXPLORATION & PRODUCTION

OVERVIEW OF 2003

Our focus within Exploration & Production is to develop, produce and explore for natural gas reserves in the Rocky Mountain and Mid-continent regions. We are currently one of the top producers in the Rocky Mountain region. Our specialty is extracting natural gas from non-conventional tight sands and coal bed methane formations. Almost all of our natural gas production is sold to Williams' Power segment.

We maintain a leadership presence in the following strategic natural gas basins:

- Piceance Basin in western Colorado;

- Powder River Basin in northeastern Wyoming;

- San Juan Basin, which stretches from northwestern New Mexico into Colorado; and

- Arkoma Basin in southeastern Oklahoma.

These basins are core to our future success with a large portion of our proved reserves being undeveloped. Thus, we plan to maintain a significant drilling program over the next several years. In addition, we manage other oil and gas interests, including an international oil and gas company, APCO Argentina, Inc., in which we own an approximate 69 percent interest.

During the first half of 2003, our strategy focused on selling assets and reducing our development drilling activity in order to raise or preserve cash to strengthen our balance sheet. In the second half of the year, after we had successfully paid down or refinanced certain debt, we resumed development drilling to levels similar to those achieved in 2002. The major accomplishments for the Exploration & Production segment during 2003 included the following:

- Completed the targeted asset sales of properties located primarily in Kansas, Colorado, Utah and New Mexico. We received net proceeds of approximately $465 million resulting in net pre-tax gains of approximately $134.8 million, including $39.7 million of pre-tax gains reported in discontinued operations related to the interests in the Raton and Hugoton basins.

- Achieved a reserves replacement rate of over 250 percent for our core retained basins. Overall, our reserves replacement rate was approximately 30 percent.

- Increased our development drilling program in the latter part of the year, returning to activity levels reached prior to 2003. Capital expenditures for 2003 were approximately $200 million.

- Decreased our selling, general and administrative costs by $7 million.

OUTLOOK FOR 2004

Our expectations for the Exploration & Production segment in 2004 include:

- A continuing development drilling program in our key basins with an increase in activity in the Piceance Basin.

- Increasing our current production level of 447 Mmcfe per day by 10 to 15 percent by the end of 2004. Approximately 80 percent of our forecasted 2004 production is hedged at prices that average $3.63 per Mcfe at a basin level. Approximately 48 percent of our estimated 2005 production is hedged at prices that average above $4.00 per Mcfe at the basin level.

Risks that may prevent us from fully accomplishing our objectives include drilling rig availability, obtaining permits as planned for drilling and any potential capital constraints.

YEAR-OVER-YEAR OPERATING RESULTS

The following discussions of the year-over-year results primarily relate to our continuing operations. However, the results do include those operations that were sold during 2003 or 2002 that did not qualify for discontinued operations reporting. The operations in the Hugoton and Raton basins qualified for discontinued operations.

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
		(MILLIONS)	
Segment revenues.......	$779.7	$860.4	$603.9
Segment profit.........	$401.4	$508.6	$231.8

2003 vs. 2002

The $80.7 million, or nine percent decrease in revenues is due primarily to $66 million lower production revenues due to lower production levels as the result of property sales and reduced drilling activities and $21 million lower other revenues primarily due to the absence in 2003 of deferred income relating to transactions in prior years that transferred certain economic benefits to a third party.

The decrease in domestic production revenues reflects $68 million associated with an eleven percent decrease in net domestic production volumes, partially offset by $2 million higher revenues from increased net realized average prices for production. Net realized average prices include the effect of hedge positions. The decrease in production volumes primarily results from the sales of properties in 2002 and 2003 and the impact of reduced drilling activity. Drilling activity was lower in the January through August period of 2003 due to our capital constraints. During the third quarter, drilling activities on our retained properties began to increase and by the fourth quarter of 2003 returned to the levels more consistent with 2002 drilling levels. This drilling level is expected to increase production volumes in the future.

To minimize the risk and volatility associated with the ownership of producing gas properties, we enter into derivative forward sales contracts, which economically lock in a price for a portion of our future production. Approximately 86 percent of domestic production in 2003 was hedged. These hedging decisions are made considering our overall commodity risk exposure.

Costs and expenses, including selling, general and administrative expenses, decreased $11 million, reflecting:

- $17 million lower exploration expenses reflecting the current focus of the company on developing proved properties while reducing exploratory activities,

- $10 million lower depreciation, depletion and amortization expense primarily as a result of lower production volumes,

- $7 million lower selling general and administrative expense, and

- $19 million higher operating taxes due primarily to higher market prices.

Other (income) expense - net in 2003 includes approximately $95.1 million in net gains on sales of natural gas properties during 2003, which were discussed previously. Other (income) expense - net in 2002 includes approximately $141 million in net gains on sales of natural gas properties during 2002.

The $107.2 million decrease in segment profit is partially due to $46 million lower net gains on sales of assets in 2003 as compared to 2002, as discussed above. Additionally, lower production revenues due primarily to lower production volumes also contributed to the decrease. Segment profit also includes $18.2 million and $11.8 million related to international activities for 2003 and 2002, respectively. This increase primarily reflects improved operating results of APCO Argentina.

2002 vs. 2001

The $256.5 million, or 42 percent, increase in revenues is primarily due to:

- $246 million higher domestic production revenues,

- $27 million in unrealized gains from mark-to-market financial instruments related to basis differentials on natural gas production, and

- $28 million lower domestic gas management revenues.

The $246 million increase in domestic production revenues includes $227 million associated with an increase in net domestic production volumes, resulting primarily from the acquisition in third-quarter 2001 of the former Barrett operations. The increase in our revenues also includes $19 million from increased net realized average prices for production (including the effect of hedge positions). Approximately 88 percent of domestic production in 2002 was hedged.

Costs and operating expenses, including selling, general and administrative expenses, increased $112 million, due primarily to the addition of the former Barrett operations. Increased costs include depreciation, depletion and amortization, lease operating expenses and selling, general and administrative expenses. These increases were partially offset by decreased gas management purchase costs.

Other (income) expense -- net in 2002 includes $120 million and $21 million in gains from the sales of substantially all of our interests in natural gas production properties in the Jonah field (Wyoming) and in the Anadarko Basin, respectively.

Segment profit increased $276.8 million due primarily to the gains from asset sales mentioned in the preceding paragraph, increased production volumes, and higher net realized average prices. Segment profit also includes $11.8 million and $15.4 million related to international activities for 2002 and 2001, respectively.

MIDSTREAM GAS & LIQUIDS

OVERVIEW OF 2003

In 2003, we continued to execute our strategy to focus on targeted growth areas in the Four Corners, Rockies and Gulf Coast production areas. Pursuing our strategy, we placed into service significant pipeline infrastructure in the deepwater offshore area of the Gulf of Mexico and added a fourth cryogenic processing train and a billion cubic feet per day dehydration plant to our Opal gas processing facility. A third party funded and owns the fourth cryogenic train mentioned above. The deepwater project contributed to segment profit in 2003 while both Opal expansions will begin contributing in 2004. While strengthening our positions in these growth areas, we also continued to rationalize assets by completing sales of various non-core assets. The following is a list of assets sold during 2003:

- Wholesale propane business, which represents the most significant portion of our NGL trading activities, and includes certain supply contracts and seven propane distribution terminals (fourth quarter).

- Dry Trail gas processing plant located in Texas County, Oklahoma (fourth quarter).

- West Stoddart gas processing facility and the fractionation, storage, and distribution system at our Redwater, Alberta plant in western Canada (third quarter).

- Ownership interest in the following investments: 45 percent interest in Rio Grande Pipeline (second quarter); 20 percent interest in the West Texas Pipeline (third quarter); 37.5 percent interest in Wilprise Pipeline (fourth quarter); and 16.67 percent interest in Tri-States NGL Pipeline (fourth quarter).

OUTLOOK FOR 2004

The following factors could impact our business in 2004 and beyond:

- Continued growth in the deepwater areas of the Gulf of Mexico is expected to contribute to, and become a larger component of, our future segment revenues and segment profit. These additional fee-based revenues will lower our relative exposure to commodity price risks.

- Gas processing margins may not be as favorable as those realized in 2002 and 2003. Although Wyoming natural gas prices are historically below natural gas prices in other domestic markets, the magnitude of this basis differential may be less in the near future.

- Midstream realized additional product gains related to its gas gathering systems in 2003. We do not consider these gains to be recurring in nature.

- In 2003, our Gulf Coast gas processing plants earned additional fee revenues derived from temporary processing agreements contracted in response to gas merchantability orders from pipeline operators requiring producers' gas to be processed to achieve pipeline quality standards. These contracts may terminate if processing economics in this region were to significantly improve.

- We continue to evaluate and pursue the sale of various assets, including the assets of our wholly-owned subsidiary Gulf Liquids New River LLC (Gulf Liquids) and certain Canadian assets, both currently reported as discontinued operations. The completion of asset sales may have the effect of lowering revenues and/or segment profit in the periods following the sales. The sale of our wholesale propane business mentioned above will reduce revenues and expenses, but should not have a material effect on our segment profit. Additional fee-based revenues from our new deepwater assets are expected to mitigate segment profit decline resulting from certain asset sales.

YEAR-OVER-YEAR OPERATING RESULTS

In August 2002, we completed the sale of 98 percent of Mapletree LLC and 98 percent of E-Oaktree, LLC to Enterprise Products Partners L.P. Mapletree owned all of Mid-America Pipeline, a 7,226-mile natural gas liquids pipeline system. E-Oaktree owned 80 percent of the Seminole Pipeline, a 1,281-mile natural gas liquids pipeline system. The gains on the sale of these businesses and the related results of operations have been reported as discontinued operations.

Pursuant to generally accepted accounting principles, we have classified the operations of Gulf Liquids, West Stoddart, Redwater and the Canadian straddle plants as discontinued operations. All prior periods reflect this reclassification.

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
		(MILLIONS)	
Segment revenues	$ 2,778.5	$ 1,143.1	$ 1,155.2
Segment profit (loss)			
Domestic Gathering & Processing	$ 272.9	$ 203.5	*
Venezuela	74.9	75.4	*
Canada	(37.1)	(100.7)	*
Other	18.0	18.7	*
Total	$ 328.7	$ 196.9	$ 173.9

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* Beginning in the third quarter of 2003, our management discussion and analysis of operating results was reorganized into major asset groups to provide additional clarity. The discussion comparing 2002 and 2001 results was not completed using the same asset groupings.

2003 vs. 2002

Revenues increased $1.6 billion primarily as a result of adopting EITF 02-3, which changed how we report natural gas liquids trading activities. The costs of such activities are no longer reported as reductions in revenues. EITF 02-3 does not require restatement of prior year amounts. In addition to this effect, our revenues increased $220 million primarily due to higher natural gas liquids (NGL) revenues at our gas processing plants as a result of moderate market price increases, partially offset by lower NGL production volumes. Additional fee revenues associated with newly constructed deepwater assets and higher olefins sales also contributed to the revenue increase.

Costs and operating expenses also increased $1.8 billion primarily due to the adoption of EITF 02-3 as discussed in the previous paragraph. In addition to this effect, costs and expenses increased $360 million, of which $113 million is attributable to rising market prices for natural gas used to replace the heating value of NGLs extracted at our gas processing facilities. Feedstock purchases for the olefins facilities increased $109 million due to higher NGL and gas prices as well as higher purchase volumes.

Segment profit increased $131.8 million primarily due to the absence of an impairment charge of $78.2 million in 2002 relating to the Redwater/Fort McMurray olefins assets. The remaining $53.6 million increase is largely attributable to higher deepwater and other Gulf Coast fee revenues partially offset by unfavorable results in our Canadian and Gulf olefins operations. Segment profit benefited from increased processing margins in both 2003 and 2002 due to rising NGL prices coupled with depressed natural gas prices in the Wyoming area. In contrast, Canadian and Gulf olefins production margins suffered as market prices for ethane and propane feedstocks increased more than those for the olefins produced at these facilities, which lowered operating results. In addition, gains on asset and investment sales, reduced selling, general and administrative expenses, and gathering system net gains are offset by lower partnership earnings and higher depreciation expense. A more detailed analysis of segment profit of our various operations is presented below:

Domestic Gathering & Processing: The $69.4 million increase in domestic gathering and processing segment profit includes a $76.1 million increase in the Gulf Coast Region, partially offset by a $6.7 million decline in the West Region.

The Gulf Coast Region's $76 million improvement is largely attributable to $42 million of incremental segment profit associated with new infrastructure in the deepwater area of the Gulf of Mexico. The Canyon Station production platform, Seahawk gas gathering pipeline, and Banjo oil transportation system were placed into service during the latter half of 2002 and each contributed to Midstream's segment profit. The remaining Gulf Coast gathering and processing assets provided approximately $34 million in additional net revenues, primarily from $12 million in higher processing margins and $23 million in higher fee-based revenues. A portion of this increase relates to the temporary processing agreements which allow producers' gas to be processed to achieve pipeline quality standards.

The West Region's $6.7 million segment profit decline reflects the absence of $7 million in operating profit associated with the Kansas Hugoton gathering system sold in August 2002. Although 2003 segment profit is comparable to 2002, the West Region's segment results were impacted by several offsetting factors discussed below:

- Gas processing margins declined $10 million compared to margins experienced in 2002. Throughout 2002 and the first quarter of 2003, rising NGL prices and depressed Wyoming natural gas prices yielded very favorable processing margins. Wyoming natural gas prices rebounded at the end of the first quarter 2003 as the completion of the Kern River Pipeline system added transportation capacity relieving downward price pressure. Margins recovered somewhat in the fourth quarter as Wyoming gas prices lagged behind the increases in other energy commodities.

- Gathering and processing fee revenues declined $11 million primarily due to fewer customers electing the fee-based billing option of processing contracts.

- Non-reimbursed fuel expenses declined $8 million, largely attributed to favorable adjustments in the annual fuel reimbursement rates. This favorable variance is not likely to continue in 2004.

- We realized $17 million in non-recurring net product gains related to our gas gathering system. These gains represent less than one-third of one percent of total gas gathered and are within industry standards. Historically our gathering system realizes net gains and losses, and therefore, we do not consider these gains to be recurring in nature.

- Depreciation expense was $10 million higher in large part due to additional investments in the West.

Venezuela: Segment profit for our Venezuelan assets remained virtually unchanged. Higher compression rates in 2003 and the 2002 currency exchange loss resulted in $11 million higher profits at the PIGAP gas compression facility. These higher profits were partially offset by an $8 million decrease in the El Furrial operating margins attributed to plant downtime caused by a fire that occurred in the first quarter of 2003. Also offsetting the increase in PIGAP operating profit is a $4 million decline resulting from the termination of the Jose Terminal operations contract in December 2002. Our Venezuelan assets were constructed and are currently operated for the exclusive benefit of Petroleos de Venezuela S.A. (PDVSA), the state owned Petroleum Corporation of Venezuela. The Venezuelan economic and political environment can be volatile, but has not significantly impacted the operations and cash flows of our facilities.

Effective February 7, 2004, the Venezuelan government revalued the fixed exchange rate for their local currency from 1,600 Bolivars to the dollar to 1,920 Bolivars to the dollar. This effect of this currency devaluation will be recorded in the first quarter of 2004 but should not have a significant impact on our first quarter segment profit.

Canada: The $63.6 million increase in segment profit for our Canadian assets is primarily due to the absence of an impairment charge of $78.2 million in 2002 relating to the Redwater/Fort McMurray olefins assets. The offsetting $14.6 million decline is primarily attributable to declining olefins production margins and higher operating expenses related to the Redwater/Fort McMurray olefins facility that became operational in April 2002.

Other: The $.7 million decline in segment profit for Midstream's other operations is attributed to lower domestic olefins margins and unfavorable partnership earnings, partially offset by the gain on sale of our wholesale propane operations.

- Segment profit for our domestic Olefins group declined $14 million primarily as a result of reduced olefins fractionation margins as the price of ethane and propane feedstock increased more than the price of olefins products. Higher maintenance expenses also contributed to the decline in segment profit. Olefins production margins continue to be impacted by weak consumer demand for products produced by petrochemical facilities.

- Our earnings from partially owned domestic assets accounted for using the equity method declined $15 million largely due to $13 million in prior period accounting adjustments recorded on the Discovery partnership and the 2003 sale of other investments that generated positive earnings in 2002. These unfavorable results were partially offset by net gains totaling approximately $20 million from the sale of our interests in the West Texas, Rio Grande, Wilprise, and Tri-states liquids pipeline partnerships.

- Segment profit for our Trading, Fractionation, and Storage group increased $14 million primarily due to a $16 million gain on the fourth-quarter 2003 sale of our wholesale propane business consisting of certain supply contracts and seven propane distribution terminals. Our NGL trading operations activities were substantially curtailed in 2003, resulting in $11 million lower selling, general, and administrative costs partially offset by $8 million in lower net trading revenues. In addition, NGL service fees declined $5 million due to the sale of several NGL terminals in 2002.

2002 vs. 2001

Our revenues decreased $12.1 million as a result of:

- a $23.0 million increase in domestic gathering, processing, transportation and liquid product sales revenues,

- a $48.7 million increase in Venezuelan revenues,

- a $33.5 million increase in Canadian revenues, and

- a $117 million decline in domestic petrochemical and trading revenues.

The $23 million increase in domestic gathering, processing, transportation, storage, fractionation and liquid product sales revenues resulted from a $34 million increase in liquid sales and a $10 million increase in transportation revenues, partially offset by a $14 million decrease in gathering revenues primarily due to the third-quarter 2002 sale of the Kansas-Hugoton gathering system, a $2 million decrease in storage revenues and a $4 million decrease in fractionation revenues. The increase in liquid sales reflects a $67 million increase in gulf coast liquid sales resulting primarily from higher production at existing processing facilities, and the September 2001 completion of a new processing facility that processes natural gas gathered from deepwater projects off the coast of Texas.

The increase in Gulf Coast liquid sales was partially offset by a $33 million decline in liquid sales in the west, primarily caused by a decline in average liquid sales prices. The $10 million increase in transportation revenues reflects the results of a new deepwater oil and gas transportation system which was completely operational by mid-year 2002.

The $117 million decline in petrochemicals and trading revenues is due largely to a September 2001 change in the reporting of certain petrochemical and liquid product trading transactions from a gross revenue basis to a net revenue basis combined with lower natural gas liquid trading margins.

The $48.7 million increase in Venezuelan revenues reflects a full year of results from a new gas compression facility that began operations in August 2001.

The increase in Canadian revenues results from a $34 million increase in olefins sales due primarily to the Canadian olefins facility being placed into service in April 2002.

Costs and operating expenses decreased $64 million, or 6 percent, primarily reflecting a decline in fuel and product shrink costs at our domestic processing facility of $21 million. This decrease reflects the impact of lower average natural gas prices in Wyoming, offset by higher volumes and prices in the Gulf Coast. The lower average gas prices in Wyoming during 2002 reflect a favorable differential between gas prices in Wyoming and the Gulf as a result of limited transportation capacity from Wyoming to other markets. This favorable basis differential had the effect of lower shrink costs and increasing liquid sales margins from Wyoming processing plants and is not expected to continue once take away transportation capacity within this region has been expanded. Costs and operating expenses also reflect a $92 million decline in petrochemical and trading costs resulting from the September 2001 change in reporting certain product trading classifications. These decreases are partially offset by $14 million higher transportation, fractionation, and marketing costs. Operations and maintenance expenses were relatively unchanged on a segment basis. A $32 million decline in costs in the west primarily, resulting from lower maintenance spending, was offset by a corresponding increase in the Gulf, Canada and Venezuela. The increase in these areas was largely associated with higher maintenance costs resulting from the new Venezuelan gas compression facility, Canadian olefins facility and new deepwater offshore operations.

Selling, general and administrative costs were relatively unchanged on a segment basis.

Other (income) expense-net within segment costs and expense for 2002 includes a $78 million impairment associated with the Canadian olefin extraction assets (see Note 4 of Notes to Consolidated Financial Statements) and a $6 million impairment associated with the sale of the Kansas Hugoton gathering system in the third quarter. Reflected in 2001 are $13.8 million of impairments associated with certain south Texas non-regulated gathering and processing assets (see Note 4 of Notes to Consolidated Financial Statements).

Segment profit increased $23 million from 2001. This increase reflects a $93 million increase in domestic operations, a $20 million increase in Venezuelan operations and a $90 million decrease in Canadian operations.

Domestic segment profit reflects a $45 million increase in liquid sales margins resulting from the low fuel and shrink costs in the west reflecting the wide basis differential for natural gas prices in Wyoming. Domestic segment profit also increased $28 million due to income from equity investments primarily related to significant improvements in the operations of Discovery pipeline following new supply connections that resulted in higher transportation and liquid volumes. Domestic segment profit was also impacted by a $16 million increase in profits from an increase in deepwater operations.

The decrease in segment profit from Canadian operations primarily relates to the $78.2 million impairment discussed above.

Segment profit from Venezuelan operations reflects an increase resulting from a full year of results following the completion of a new gas compression facility in August 2001.

OTHER

OVERVIEW OF 2003

During 2003, we began reporting the Petroleum Services segment within Other as a result of a significant portion of the Petroleum Services assets being reflected as discontinued operations. Other now includes corporate operations, certain international activities and the remaining continuing operations of Petroleum Services.

OUTLOOK FOR 2004

During February 2004, we were a party to a recapitalization plan completed by Longhorn Partners Pipeline, L.P. (Longhorn). As a result of this plan, we sold a portion of our equity investment in Longhorn for $11.4 million, received $58 million in repayment of a portion of our advances to Longhorn and converted the remaining advances, including accrued interest, into preferred equity interests in Longhorn. These preferred equity interests are subordinate to the preferred interests held by the new investors. No gain or loss was recognized on this transaction.

YEAR-OVER-YEAR OPERATING RESULTS

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
		(MILLIONS)	
Segment revenues..............	$ 72.0	$124.1	$319.3
Segment profit (loss).........	$(50.5)	$ 14.1	$ 37.5

2003 vs. 2002

Other segment loss for 2003 includes a $43.1 million impairment related to our investment in Longhorn. The impairment resulted from our assessment that indicated there had been an other than temporary decline in the fair value of this investment. Longhorn equity earnings increased $15.7 million during 2003 from a loss of $13.8 million in 2002. The 2002 segment profit includes a $58.5 million gain on the sale of our 27 percent ownership interest in the Lithuanian operations partially offset by a $12.6 million equity loss for those operations.

2002 vs. 2001

The $195.2 million, or 61 percent, decrease in revenues is due primarily to $184 million lower convenience store revenues after the sale in May 2001 of 198 convenience stores.

Other segment profit in 2002 includes a $58.5 million gain from the September 2002 sale of our 27 percent ownership interest in the Lithuanian refinery, pipeline and terminal complex and a $9.5 million decrease in equity losses from the Lithuanian operations for the period. We received proceeds of approximately $85 million from the sale of this investment. In addition, we sold our $75 million note receivable from the Lithuanian operations at face value. Equity losses related to Longhorn increased $13.9 million from 2001 to 2002. Included in 2001 segment profit is a $75.3 million gain on the sale of 198 convenience stores.

ENERGY TRADING ACTIVITIES

As of December 31, 2002, we carried energy and energy-related contracts on the Consolidated Balance Sheet at fair value. We held all of these energy and energy-related contracts for trading purposes. As of December 31, 2002, we reported net assets of approximately $1,632 million related to the fair value of energy risk management and trading contracts. Of this value, approximately $1,193 million pertained to non-derivative energy contracts, which were reflected at fair value under EITF Issue No. 98-10. On October 25, 2002 in Issue No. 02-3, the EITF rescinded Issue No. 98-10. With the adoption of EITF 02-3 on January 1, 2003, we reversed this non-derivative fair value through a cumulative adjustment from a change in accounting principle. These contracts are now accounted for under the accrual method. Effective January 1, 2003, only energy contracts meeting the definition of a derivative are reflected at fair value on the Consolidated Balance Sheet.

FAIR VALUE OF TRADING DERIVATIVES

Consistent with our announcement to exit the merchant power and generation business, in 2003 we assessed which derivative contracts we held for trading purposes and which we held for non-trading purposes. We consider trading derivatives to be those held to provide price risk management services to third-party customers. The chart below reflects the fair value of derivatives held for trading purposes as of December 31, 2003. We have presented the fair value of assets and liabilities by period in which they are expected to be realized.

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)	TOTAL FAIR VALUE
		(MILLIONS)		
$ (3)	$ 25	$ 22	$ (5)	$ 39

As the table above illustrates, we are not materially engaged in trading activities. However, we hold a substantial portfolio of non-trading derivative contracts. Non-trading derivative contracts are those that hedge or could possibly hedge Power's long-term structured contract positions and the activities of our other segments on an economic basis. Certain of these economic hedges have not been designated as or do not qualify as SFAS No. 133 hedges. As such, changes in the fair value of these derivative contracts are reflected in earnings. We also hold certain derivative contracts, which do qualify as SFAS No. 133 cash flow hedges, which primarily hedge Exploration & Production's forecasted natural gas sales. As of December 31, 2003, the fair value of these non-trading derivative contracts was a net asset of $435 million.

METHODS OF ESTIMATING FAIR VALUE

Most of the derivatives we hold settle in active periods and markets in which quoted market prices are available. Quoted market prices in active markets are readily available for valuing forward contracts, futures contracts, swap agreements and purchase and sales transactions in the commodity and capital markets in which we transact. While an active market may not exist for the entire period, quoted prices can generally be obtained for the following:

- natural gas through 2013,
- power through 2007,
- crude and refined products through 2005,
- natural gas liquids through 2004, and
- interest rates through 2033.

These prices reflect the economic and regulatory conditions that currently exist in the marketplace and are subject to change in the near term due to changes in market conditions. The availability of quoted market prices in active markets varies between periods and commodities based upon changes in market conditions. The ability to obtain quoted market prices also varies greatly from region to region. The time periods noted above are an estimation of aggregate liquidity. We use prices of current transactions to further validate price estimates. However, the decline in overall market liquidity since 2002 has limited our ability to validate prices.

We estimate energy commodity prices in illiquid periods by incorporating information about commodity prices in actively quoted markets, quoted prices in less active markets, and other market fundamental analysis.

Due to the adoption of EITF 02-3, modeling and other valuation techniques are not used significantly in determining the fair value of our derivatives. Such techniques were primarily used in previous years for valuing non-derivative contracts, which are no longer reported at fair value, such as transportation, storage, full requirements, load serving, transmission and power tolling contracts (see Note 1 of Notes to Consolidated Financial Statements).

COUNTERPARTY CREDIT CONSIDERATIONS

We include an assessment of the risk of counterparty non-performance 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 December 31, 2003, we held collateral support of $342 million.

We also enter into netting agreements to mitigate counterparty performance and credit risk. In 2002 and 2003, we closed out various trading positions. During 2003, we did not incur any significant losses due to recent counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts as of December 31, 2003 is summarized below.

COUNTERPARTY TYPE	INVESTMENT GRADE(a)	TOTAL
	(MILLIONS)	
Gas and electric utilities	$ 988.2	$1,045.9
Energy marketers and traders	1,317.2	3,118.5
Financial Institutions	918.5	918.5
Other	609.8	619.3
	$3,833.7	5,702.2
Credit reserves		(39.8)
Gross credit exposure from derivatives(b)		$5,662.4

We assess our credit exposure on a net basis. The net credit exposure from our derivatives as of December 31, 2003 is summarized below.

COUNTERPARTY TYPE	INVESTMENT GRADE(a)	TOTAL
	(MILLIONS)	
Gas and electric utilities	$ 606.1	$ 629.4
Energy marketers and traders	52.1	376.3
Financial Institutions	160.4	160.4
Other	--	.2
	$ 818.6	1,166.3
Credit reserves		(39.8)
Net credit exposure from derivatives(b)		$1,126.5

(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.

(b) One counterparty within the California power market represents more than ten percent of the derivative assets and is included in investment grade. Standard & Poor's and Moody's Investors Service do not currently rate this counterparty. We included this counterparty in the investment grade column based upon contractual credit requirements in the event of assignment or substitution of a new obligation for the existing one.

FINANCIAL CONDITION AND LIQUIDITY

LIQUIDITY

Overview of 2003

Entering 2003, we faced significant liquidity challenges with sizeable maturing debt obligations and limited financial flexibility due in part to covenants arising from 2002 short-term financings. Our plan to address these issues, announced in February 2003, required immediate execution of significant levels of asset sales to meet maturing obligations in excess of $1 billion by mid-year.

Through June 30, we were successful in generating approximately $2.4 billion of net proceeds from the sale of assets. With sufficient liquidity in hand, we prepaid the RMT Note totaling $1.15 billion. During the same period, we enhanced overall liquidity through the following actions:

- obtained a new $800 million revolving and letter of credit facility that is collateralized by cash and/or government securities, but allows operation with minimal covenants, none of which contain financial ratios;

- issued $800 million of 8.625 percent senior unsecured notes due 2010, which provided added liquidity in advance of remaining asset sales and flexibility to use funds to retire the $1.4 billion senior unsecured 9.25 percent notes maturing in March 2004;

- redeemed the $275 million 9.875 percent cumulative-convertible preferred shares through the issuance of $300 million of 5.5 percent junior subordinated convertible debentures;

- through our RMT subsidiary, obtained a new $500 million term loan at market rates and collateralized by RMT assets, the proceeds of which were used together with other funds to repay the RMT Note; and

- through our Northwest Pipeline subsidiary, issued $175 million of 8.125 percent senior unsecured notes due 2010, which enabled Northwest Pipeline to fund capital expenditures without borrowing cash from our parent company.

During the fourth quarter of 2003, we continued the execution of our plan to reduce debt with available funds by tendering for and retiring debt of nearly $1 billion. Of this total, $721 million was comprised of the 9.25 percent notes due March 2004, leaving $679 million outstanding.

During 2003, we generated net cash proceeds from asset sales of approximately $3.0 billion. We expect to realize approximately $800 million from additional asset sales in 2004. The remaining expected asset sales include our Alaska refinery and related operations, which are currently under contract for sale, and certain Midstream assets. Our 2003 cash flow from operations of $770 million funded a large portion of our capital spending requirements for the year. At December 31, 2003, we have available unrestricted cash on hand of approximately $2.3 billion.

Sources of liquidity

Our liquidity is derived from both internal and external sources. Certain of those sources are available to us (at the parent level) and others are available to certain of our subsidiaries.

At December 31, 2003, we have the following sources of liquidity:

- Cash-equivalent investments at the corporate level of $2.2 billion as compared to $1.3 billion at December 31, 2002.

- Cash and cash-equivalent investments of various international and domestic entities of $91 million, as compared to $352 million at December 31, 2002.

At December 31, 2003, we have capacity of $447 million available under our current revolving and letter of credit facility. In June 2003, we entered into this revolving and letter of credit facility which is used primarily for issuing letters of credit and must be collateralized at 105 percent of the level utilized (see Note 11 of Notes to Consolidated Financial Statements). As discussed below in the Outlook for 2004 section, we intend to replace this facility in 2004 with facilities that do not require cash collateralization. In contrast, at December 31, 2002 we had a combined $466 million available under the previous revolver and letter of credit facilities.

In addition to these sources of liquidity described above, we have an effective shelf registration statement with the Securities and Exchange Commission that authorizes us to issue an additional $2.2 billion of a variety of debt and equity securities. However, the ability to utilize this shelf registration for debt securities is restricted by certain covenants associated with our $800 million 8.625 percent senior unsecured notes (see Note 11 of Notes to Consolidated Financial Statements).

In addition, our wholly owned subsidiaries Northwest Pipeline and Transco have outstanding registration statements filed with the Securities and Exchange Commission. As of December 31, 2003, approximately $350 million of shelf availability remains under these registration statements. However, the ability to utilize these registration statements is restricted by certain covenants associated with our $800 million 8.625 percent senior unsecured notes. Interest rates, market conditions, and industry conditions will affect amounts raised, if any, in the capital markets. On March 4, 2003, Northwest Pipeline completed an offering of $175 million of 8.125 percent senior notes due 2010. These notes contain covenants similar to those of the $800 million 8.625 percent senior unsecured notes discussed above. The $350 million of shelf availability mentioned above was not utilized for this offering.

During 2003, we supplied liquidity needs with:

- Cash generated from the sale of assets -- In 2003, we generated approximately $3.0 billion in net proceeds from asset sales and expect to realize approximately $800 million from additional asset sales in 2004.

- Cash generated from operations -- In 2003, we generated $607.9 million in cash flow from continuing operations and expect to generate $1.0 to $1.3 billion in 2004.

We estimate approximately $700 million to $800 million for 2004 capital and investment expenditures. We expect to fund capital and investment expenditures, debt payments and working-capital requirements through (1) cash and cash equivalent investments on hand, (2) cash generated from operations, and (3) cash generated from the sale of assets.

Outlook for 2004

In 2004, we expect to make significant additional progress towards debt reduction while maintaining appropriate levels of cash and other forms of liquidity. To manage our operations and meet unforeseen or extraordinary calls on cash, we expect to maintain cash and/or liquidity levels of at least $1 billion. While access to the capital markets continues to improve, one of our indentures has a covenant that restricts our ability to issue new debt, with minimal exceptions, until a certain fixed charge coverage ratio is achieved. We expect to satisfy this requirement by the end of 2005. The covenant does not prohibit us from replacing our existing revolving and letter of credit facility with new facilities. Several of our indentures contain covenants restricting our ability to grant liens securing debt, but such covenants all contain significant exceptions allowing us to incur secured debt without granting similar liens to the holders of notes under those indentures. In determining the appropriate level of liquidity, we have considered the potential impact of significant swings in commodity prices, contract margin requirements, unplanned calls on capital spending and the need for a reserve for near term scheduled debt payments.

During 2004, we expect to reduce long term debt, including scheduled maturities of approximately $936 million, based on the following assumptions:

- generation of approximately $800 million from additional asset sales,

- generation of cash flow from operations by our businesses in excess of capital spending levels,

- replacement of our revolving and letter of credit facility with facilities that do not require cash collateralization, and

- utilization of available cash on hand in excess of minimum liquidity levels.

Successful execution of this plan does not require us to incur new debt.

Potential risks associated with achieving this objective include:

- Lower than expected levels of cash flow from operations.

  To mitigate this exposure, Exploration & Production has hedged the price of natural gas for approximately 80 percent of its expected 2004 production. Power estimates that it has hedged revenues, of varying degrees of certainty, covering approximately 98 percent of its fixed demand obligations through 2010.

- Delays in asset sales or lower than expected proceeds.

  Approximately one-third of the remaining asset sales are currently under contract and expected to close during the first quarter. If these sales do not close, we will not be precluded from meeting our operating commitments.

- Sensitivity of margin requirements associated with our marginable commodity contracts.

  As of February 2004, we estimate our exposure to additional margin requirements over the next 360 days to be as much as $350 million.

- Exposure associated with our efforts to resolve regulatory and litigation issues arising from the Power business and the ongoing defense of certain shareholder litigation (see Note 16 of Notes to Consolidated Financial Statements).

- Ability to replace our revolver and letter of credit facility on satisfactory terms.

Based on our available cash on hand and expected cash flows from operations, we believe we have, or have access to, the financial resources and liquidity necessary to meet future cash requirements and maintain a sufficient level of liquidity to reasonably protect against unforeseen circumstances requiring the use of funds.

Credit ratings

During 2002, our credit ratings were downgraded to below investment grade and remained below investment grade throughout 2003. As a result, Power's participation in energy risk management and trading activities requires alternate credit support under certain agreements. In addition, we are required to fund margin requirements pursuant to industry standard derivative agreements with cash, letters of credit or other negotiable instruments. Currently, we are effectively required to post margins of 100 percent or more on forward contracts in a loss position. Future liquidity requirements relating to these instruments will be based on changes in their value resulting from changes in factors such as price and volatility.

As part of the plan announced in February of 2003, we established a goal of returning to investment grade status. While reduction of debt is viewed as a key contributor towards this goal, certain of the key credit rating agencies have imputed the financial commitments associated with our long-term tolling agreements within the Power business as debt. If we are unable to achieve our goal of exiting the Power business and/or the elimination of these commitments, receiving an investment grade rating may be further delayed.

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

At December 31, 2001, we had operating lease agreements with special purpose entities (SPE's) relating to certain of our travel center stores (included in discontinued operations), offshore oil and gas pipelines and an onshore gas processing plant. As a result of changes to the leases in conjunction with the secured financing facilities completed in July 2002, they no longer qualified for operating lease treatment. The operating leases for the offshore oil and gas pipelines and onshore gas processing plant were recorded as capital leases within long-term debt at that time and were repaid in May 2003. The travel center lease was reported in liabilities of discontinued operations and was repaid in March 2003 pursuant to the travel centers sale.

We had agreements to sell, on an ongoing basis, certain of our accounts receivable to qualified special-purpose entities. On July 25, 2002, these agreements expired and were not renewed.

In May 2002, we provided a guarantee of approximately $127 million towards project financing of energy assets owned and operated by Discovery Producer Services LLC (Discovery) in which we own a 50 percent interest. This obligation was not consolidated in our balance sheet as we account for our interest under the equity method of accounting. The guarantee was scheduled to expire at the end of 2003. However, in December 2003, we made an additional $127 million investment in Discovery which was used to fully repay maturing debt satisfying the guarantee obligation. All owners contributed amounts equal to their ownership percentage. (See the Investing Activities section for discussion of additional investment).

We have provided guarantees in the event of nonpayment by WilTel on certain of its lease performance obligations that extend through 2042 and have a maximum potential exposure of approximately $51 million and $53 million at December 31, 2003 and 2002, respectively. Our exposure declines systematically throughout the remaining lease terms. The recorded carrying value of these guarantees was $46 million and $48 million at December 31, 2003 and 2002 respectively.

In addition to these guarantees, we have issued guarantees and other similar arrangements with off-balance sheet risk as discussed under Guarantees in Note 15 of Notes to Consolidated Financial Statements.

OPERATING ACTIVITIES

The increase in cash flow from operations from 2002 levels is primarily due to the following:

- improvement in Income (loss) from continuing operations by $625.3 million,

- the absence of $753.9 million in payment of guarantees and payment obligations related to WilTel,

- the reduction of margin funding requirements of $885.6 million, and

- the increase in cash flow due to changes in accounts and notes receivable of $425 million.

The increase in Income (loss) from continuing operations is reflective of the overall improvement in the performance of our operating units. However, the noted improvement in Income (loss) from continuing operations had a lesser impact on cash flow from operations because Income (loss) from continuing operations in 2002 included higher non-cash expenses of $167.2 million for losses on property and other assets and the $268.7 million provision for uncollectible accounts from WilTel. The improvement in margin funding requirements is a result of our decreased activity in the Power business. We expect a continued decrease in margin funding requirements in 2004 as we continue to manage our current positions to reduce risk and exit other positions, which reduces our overall activity. The increase in operating cash flow related to decreased accounts receivable is a reflection of the continued decrease in activity in the Power business in 2003. Cash flow from operations for 2004 is expected to be sufficient to fund the projected 2004 capital expenditures of $700 million to $800 million.

In March 2002, WilTel exercised its option to purchase certain network assets under the ADP transaction for which we had previously provided a guarantee. On March 29, 2002, as guarantor under the agreement, we paid $753.9 million related to WilTel's purchase of these network assets. In 2002, we recorded in continuing operations additional pre-tax charges of $268.7 million related to the settlement of these receivables and claims. In 2001, we had recorded a $188 million charge related to estimated recovery of amounts from WilTel (see Note 2 of Notes to Consolidated Financial Statements).

The increase in net income and other increases in cash flows from operations were offset by:

- a $929.5 million decrease in derivative and energy risk management and trading net assets and liabilities; and

- a $265.0 million payment on deferred set-up fee and fixed rate interest on the RMT note payable.

The decrease in funds associated with derivative and energy risk management and trading assets and liabilities during 2003 is a result of the decline in the activity of the Power business. As we continue to reduce our activity in the Power business, the cash requirements tied to working capital and margin deposits will continue to decrease.

During 2003, we recorded approximately $231.9 million in provisions for losses on property and other assets and a net gain on disposition of assets of $142.8 million (see Notes 3 and 4 of Notes to Consolidated Financial Statements).

The accrual for fixed rate interest included in the RMT Note on the Consolidated Statement of Cash Flows represents the quarterly non-cash reclassification of the deferred fixed rate interest from an accrued liability to the RMT Note. The amortization of deferred set-up fee and fixed rate interest on the RMT Note relates to amounts recognized in the income statement as interest expense, which were not payable until maturity. The RMT Note was repaid in May 2003 (see Note 11 of Notes to Consolidated Financial Statements).

FINANCING ACTIVITIES

During 2003, we made significant progress in executing our business plan. We retired $3.2 billion in debt, redeemed $275 million in preferred stock, and issued $2 billion in debt at more favorable market rates. In 2004, we plan to further reduce debt with funding from (1) available cash on hand, (2) cash from asset sales, (3) operating cash flow after capital expenditures, and (4) the release of cash currently used as collateral. As discussed in the Outlook section, we plan to replace our existing revolver and letter of credit facility with new credit facilities that do not require cash collateralization.

Significant borrowings and repayments during 2003 included the following:

- On March 4, our Northwest Pipeline subsidiary completed an offering of $175 million of 8.125 percent senior notes due 2010. Proceeds from the issuance were used for general corporate purposes, including the funding of capital expenditures.

- On May 28, we issued $300 million of 5.5 percent junior subordinated convertible debentures due 2033. The proceeds were used to redeem all of the outstanding 9.875 percent cumulative-convertible preferred shares (see Note 13 of Notes to Consolidated Financial Statements).

- In May, we repaid the RMT note payable of Williams Production RMT Company totaling $1.15 billion, which included certain contractual fees and deferred interest.

- On May 30, a subsidiary in our Exploration & Production segment entered into a $500 million secured note due May 30, 2007, at a floating interest rate of LIBOR plus 3.75 percent. This loan refinances a portion of the RMT Note discussed above. On February 25, 2004 we completed an amendment that provided more favorable terms including a lower interest rate and an extension of the maturity by one year (see Note 11 of Notes to Consolidated Financial Statements).

- On June 6, we entered into a two-year $800 million revolving and letter of credit facility, primarily for the purpose of issuing letters of credit. Along with our subsidiaries Northwest Pipeline and Transco, we have access to all unborrowed amounts under the facility. The facility must be secured by cash and/or acceptable government securities with a market value of at least 105 percent of the then outstanding aggregate amount available for drawing under all letters of credit, plus the aggregate amount of all loans then outstanding.

- On June 10, we issued $800 million of 8.625 percent senior unsecured notes due 2010. The notes were issued under our $3 billion shelf registration statement. See Note 11 of Notes to Consolidated Financial Statements for a description of the terms and covenants related to this issuance. The proceeds were used to improve corporate liquidity, general corporate purposes, and payment of maturing debt obligations.

- On June 10, we also redeemed all the outstanding 9.875 percent cumulative-convertible preferred shares for approximately $289 million, plus $5.3 million for accrued dividends.

- On October 8, we announced a cash tender offer for any and all of our $1.4 billion senior unsecured 9.25 percent notes due in March 2004, as well as cash tender offers and consent solicitations for approximately $241 million of additional notes and debentures. At the expiration of the offers, we received tenders of debt securities with an aggregate principal amount of approximately $951 million. In conjunction with the tendered notes and related consents, we paid premiums of approximately $58 million. The premiums, as well as related fees and expenses, together totaling $66.8 million, were recorded in fourth-quarter 2003 as a pre-tax charge to earnings.

- In October, our PIGAP high-pressure gas compression project in Venezuela obtained $230 million in non-recourse financing. We own a 70 percent interest in the project and, therefore, the debt is reflected on our Consolidated Balance Sheet ($22 million in current portion of long-term debt, $208 million in long-term debt). Proceeds from the loan were used to repay us for notes due and the other owner for a portion of the initial funding of construction-related costs. Upon the execution of the loan, the project made additional cash distributions to the owners based on their respective ownership interests. We received approximately $183 million in cash proceeds, net of amounts paid relating to an up front premium, the purchase of an interest rate lock and cash used to fund a debt service reserve.

For a discussion of other borrowings and repayments in 2003, see Note 11 of Notes to Consolidated Financial Statements.

In 2002, notes payable payments were $1.1 billion net of notes payable proceeds while long-term debt proceeds was $945.3 million net of long term debt payments. Significant borrowings and repayments in 2002 included the following:

- On January 14, we completed the sale of 44 million publicly traded units, commonly known as FELINE PACS, that include a senior debt security and an equity purchase contract, for net proceeds of approximately $1.1 billion (see Note 13 of Notes to Consolidated Financial Statements).

- On March 19, we issued $850 million of 30-year notes with an interest rate of 8.75 percent and $650 million of 10-year notes with an interest rate of 8.125 percent. The proceeds were used to repay approximately $1.4 billion outstanding commercial paper, provide working capital and for general corporate purposes.

- In May, Power entered into an agreement which transferred the rights to certain receivables, along with risks associated with that collection, in exchange for cash. Due to the structure of the agreement, Power accounted for this transaction as debt collateralized by the claims. The $79 million of debt at December 31, 2003 and 2002 is classified as current on the Consolidated Balance Sheet. The debt is classified as current because if at any time the value of the underlying receivables decreases or becomes questionable, the liability will be required to be paid.

- RMT entered into a $900 million credit agreement dated as of July 31, 2002. As discussed previously, this amount was repaid in May 2003.

Dividends paid on common stock are currently $.01 per common share on a quarterly basis and totaled $20.8 million for the year ended December 31, 2003. One of the covenants under the indenture for the $800 million senior unsecured notes due 2010 currently limits our quarterly common stock dividends to not more than $.02 per common share. This restriction will be removed in the future if certain requirements in the covenants are met (see Note 11 of Notes to Consolidated Financial Statements). In 2003, we also paid $32.6 million in accrued dividends on the 9.875 percent cumulative-convertible preferred shares that were redeemed in June 2003. The $32.6 million of deferred dividends paid includes the 2003 payment of $6.8 million in dividends accrued at December 31, 2002. The $29.5 million of preferred stock dividends reported on the Consolidated Statement of Operations also includes $3.7 million of issuance costs.

In December 2001, we received net proceeds of $95.3 million from the sale of a non-controlling preferred interest in Piceance Production Holdings LLC (Piceance) to an outside investor. During 2000, we received net proceeds totaling $546.8 million from the sale of a preferred return interest in Snow Goose Associates, L.L.C. (Snow Goose) to an outside investor (see Note 12 of Notes to Consolidated Financial Statements). During 2002, changes to these limited liability company member interests and interests in Castle Associates L.P. (Castle) required classification of these outside investor interests as debt. The changes to the Snow Goose structure also included the repayment of the investor's preferred interest in installments. During 2002, approximately $558 million was repaid related to these interests and is included in the payments of long-term debt. During 2003, the remaining balances associated with the above interests were paid. Approximately $323 million of payments were made and are included in payments of long-term debt for 2003 (see Note 12 of Notes to Consolidated Financial Statements.)

In third-quarter 2002, the downgrade of our senior unsecured rating below BB by Standard & Poor's, and Ba1 by Moody's Investors Service, resulted in the early retirement of an outside investor's preferred ownership interest for $135 million (see Note 12 of Notes to Consolidated Financial Statements).

In December 1999, we formed Williams Capital Trust I, which issued $175 million in our zero-coupon obligated, mandatorily-redeemable preferred securities. In April 2001, we redeemed our obligated, mandatorily-redeemable preferred securities for $194 million. We used proceeds from the sale of the Ferrellgas senior common units for this redemption.

Long-term debt, including debt due within one year was $12.0 billion at December 31, 2003 compared to $12.2 billion at December 31, 2002.

Significant items reflected as discontinued operations within financing activities in the Consolidated Statement of Cash Flows, including the cash provided by financing activities, included the following items:

2002

- Proceeds from long-term debt of Williams Energy Partners LP related to financing entered into in 2002 of $489 million.

- Net proceeds from issuance of common units by Williams Energy Partners LP in 2002 of $279 million.

2001

- Proceeds from issuance of $1.4 billion of WCG Note Trust Notes for which we provided indirect credit support. WilTel retained all of the proceeds from this issuance (see Note 2 of Notes to Consolidated Financial Statements).

INVESTING ACTIVITIES

Capital expenditures by segment are presented below.

SEGMENT	CAPITAL EXPENDITURES 2003	2002	2001
		(MILLIONS)	
Power..........	$ 1.0	$ 135.8	$ 103.7
Gas Pipeline...	497.6	672.0	535.5
E&P............	202.0	364.1	202.6
Midstream......	252.9	432.8	554.9
Other..........	2.5	57.3	60.4
TOTAL....	$956.0	$1,662.0	$1,457.1

- Power made capital expenditures in 2002 and 2001 primarily to purchase power-generating turbines.

- Gas Pipeline made capital expenditures in 2001 through 2003 primarily to expand deliverability into the east and west coast markets. Planned expenditures for 2004 are primarily for pipeline maintenance.

- Exploration & Production made capital expenditures in 2001 through 2003 primarily for continued development of our natural gas reserves through the drilling of wells. Planned expenditures for 2004 are expected to be for similar activities.

- Midstream made capital expenditures in 2001 through 2003 primarily to acquire, expand, develop and modernize gathering and processing facilities and terminals. Included in capital expenditures are the following amounts related to the deepwater project: 2003 -- $189 million; 2002 -- $343 million; and 2001 -- $136 million. Planned expenditures for 2004 are expected to be for similar activities.

The acquisition of businesses in 2001 reflects our June 11, 2001, acquisition of 50 percent of Barrett's outstanding common stock in a cash tender offer of $73 per share for a total of approximately $1.2 billion. On August 2, 2001, we completed the acquisition of Barrett by issuing 29.6 million shares of our common stock in exchange for the remaining Barrett shares.

Purchase of investments/advances to affiliates in 2003 consists primarily of $127 million of additional investment by Midstream in Discovery. The cash investment was used by Discovery to pay maturing debt (see Note 3 of Notes to Consolidated Financial Statements). Purchases in 2002 include approximately $234 million towards the development of the Gulfstream joint venture project, one of our equity method investments. In 2001, we contributed $437 million toward the development of our joint interest in the Gulfstream project.

In 2003, we purchased $739.9 million of restricted investments comprised of U.S. Treasury notes. We sold $10 million of these notes and retired $341.8 million on their scheduled maturity date. We made these purchases and sales to satisfy the 105 percent cash collateralization covenant in the $800 million revolving credit facility (see Note 11 of Notes to Consolidated Financial Statements).

In 2003 and 2002, we realized significant cash proceeds from asset dispositions, the sales of businesses, and the disposition of investments as part of our overall plan to increase liquidity and reduce debt. The following sales provided significant proceeds from sales and include various adjustments subsequent to the actual date of sale:

In 2003:

- $803 million related to the sale of Texas Gas Transmission Corporation;

- $465 million related to the sale of certain natural gas exploration and production properties in Kansas, Colorado, New Mexico and Utah;

- $452 million related to the sale of the Midsouth refinery;

- $455 million (net of cash held by Williams Energy Partners) related to the sale of our general partnership interest and limited partner investment in Williams Energy Partners;

- $246 million related to the sale of certain natural gas liquids assets in Redwater, Alberta, Canada; and

- $188 million related to the sale of the Williams travel centers.

In 2002:

- $1.15 billion related to the sale of Mid-American and Seminole Pipeline;

- $464 million related to the sale of Kern River;

- $380 million related to the sale of Central;

- $326 million related to the sale of properties in the Jonah Field and the Anadarko Basin;

- $229 million related to the sale of the Cove Point LNG facility; and

- $173 million related to the sale of our interest in Alliance Pipeline.

Proceeds received from disposition of investments and other assets in 2001 reflect our sale of the Ferrellgas senior common units to an affiliate of Ferrellgas for proceeds of $199 million in April 2001 and our sale of certain convenience stores for approximately $150 million in May 2001.

We received $180 million in cash proceeds from the sale of notes receivable from WilTel to Leucadia in fourth-quarter 2002. See Note 2 of Notes to Consolidated Financial Statements for further discussion of WilTel items and amounts.

In 2001, Purchase of assets subsequently leased to seller reflects our purchase of the Williams Technology Center, other ancillary assets and three corporate aircraft for $276 million. These assets were sold to WilTel in 2002.

Significant items reflected as discontinued operations within investing activities on the Consolidated Statement of Cash Flows include the following:

- capital expenditures and purchases of investments by WilTel, totaling $1.5 billion in 2001;

- capital expenditures of Kern River, primarily for expansion of its interstate natural gas pipeline system, of $134 million in 2001; and

- capital expenditures of Texas Gas, primarily for expansion of its interstate natural gas pipeline system, of $41.9 million and $106.2 million in 2002 and 2001, respectively.

CONTRACTUAL OBLIGATIONS

The table below summarizes the maturity dates of our contractual obligations by period.

	2004	2005-2006	2007-2008	THEREAFTER	TOTAL
			(MILLIONS)		
Notes payable	$ 3	$ -	$ -	$ -	$ 3
Long-term debt, including current portion:					
Principal	933	1,219	2,405(1)	7,448	12,005
Interest	856	1,548	1,253	6,449	10,106
Capital leases	-	-	-	-	-
Operating leases(2)	57	69	44	68	238
Purchase obligations:					
Fuel conversion and other service contracts(3)	391	797	814	4,669	6,671
Other	807(4)	412	226	387(5)	1,832
Other long-term liabilities, including current portion:					
Physical & financial derivatives:(6)	1,844	1,048	381	623	3,896
Other	33	97	35	30	195
Total	$ 4,924	$ 5,190	$ 5,158	$ 19,674	$ 34,946

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(1) Includes $1.1 billion of 6.5 percent notes payable in 2007 which are subject to remarketing in 2004 (FELINE PACS). These FELINE PACS include equity forward contracts attached which require the holder to purchase shares of our common stock in 2005. If the 2004 remarketing is unsuccessful and a second remarketing in 2005 is also unsuccessful, then we could exercise our right to foreclose on the notes in order to satisfy the obligation of the holders of the equity forward contracts requiring the holder to purchase our common stock. This would be a non-cash transaction.

(2) Total operating lease payments include $26 million related to discontinued operations.

(3) Power has entered into certain contracts giving us the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are currently in operation throughout the continental United States.

(4) Includes $385 million for a crude purchase contract with the state of Alaska which expires in September 2004. It is anticipated that the expected sale of the Alaska refinery in the first quarter of 2004 will result in the cancellation of our obligations under this contract.

(5) Includes one year of annual payments totaling $3 million for contracts with indefinite termination dates.

(6) Although the amounts presented represent expected cash outflows, a portion of those obligations have previously been paid in accordance with third party margining agreements. As of December 31, 2003, we have paid $571 million in margins, adequate assurance, and prepays related to the obligations included in this disclosure. In addition, expected offsetting cash inflows resulting from product sales or net positive settlements are not reflected in these amounts. The offsetting expected cash inflows as of December 31, 2003 are $5.8 billion. In addition, the obligations for physical and financial derivatives are based on market information as of December 31, 2003. Because market information changes daily and has the potential to be volatile, significant changes to the values in this category may occur.

EFFECTS OF INFLATION

Our cost increases in recent years have benefited from relatively low inflation rates during that time. Approximately 50 percent of our gross property, plant and equipment is at Gas Pipeline and approximately 50 percent is at other operating units. Gas Pipeline is subject to regulation, which limits recovery to historical cost. While amounts in excess of historical cost are not recoverable under current FERC practices, we anticipate being allowed to recover and earn a return based on increased actual cost incurred to replace existing assets. Cost based regulation, along with competition and other market factors, may limit our ability to recover such increased costs. For the other operating units, operating costs are influenced to a greater extent by specific price changes in oil and natural gas and related commodities than by changes in general inflation. Crude, refined product, natural gas, natural gas liquids and power prices are particularly sensitive to OPEC production levels and/or the market perceptions concerning the supply and demand balance in the near future.

ENVIRONMENTAL

We are a participant in certain environmental activities in various stages involving assessment studies, cleanup operations and/or remedial processes at certain sites, some of which we currently do not own (see Note 16 of Notes to Consolidated Financial Statements). We are monitoring these sites in a coordinated effort with other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), or other governmental authorities. We are jointly and severally liable along with unrelated third parties in some of these activities and solely responsible in others. Current estimates of the most likely costs of such cleanup activities are approximately $74 million, all of which is accrued at December 31, 2003. We expect to seek recovery of approximately $28 million of the accrued costs through future natural gas transmission rates. The remainder of these costs will be funded from operations. During 2003, we paid approximately $18 million for cleanup and/or remediation and monitoring activities. We expect to pay approximately $24 million in 2004 for these activities. Estimates of the most likely costs of cleanup are generally based on completed assessment studies, preliminary results of studies or our experience with other similar cleanup operations. At December 31, 2003, certain assessment studies were still in process for which the ultimate outcome may yield significantly different estimates of most likely costs. Therefore, the actual costs incurred will depend on the final amount, type and extent of contamination discovered at these sites, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

We are subject to the federal Clean Air Act and to the federal Clean Air Act Amendments of 1990 which require the EPA to issue new regulations. We are also subject to regulation at the state and local level. In September 1998, the EPA promulgated rules designed to mitigate the migration of ground-level ozone in certain states. We anticipate that during 2004, the EPA will promulgate additional rules regarding hazardous air pollutants. We estimate that capital expenditures necessary to install emission control devices on our Transco system over the next five years to comply with rules will be between $230 million and $260 million. The actual costs incurred will depend on the final implementation plans developed by each state to comply with these regulations. We consider these costs on our Transco system associated with compliance with these environmental laws and regulations to be prudent costs incurred in the ordinary course of business and, therefore, recoverable through its rates.

In December 1999, standards promulgated by the EPA for tailpipe emissions and the content of sulfur in gasoline were announced. Our estimation is that capital expenditures necessary to bring our refinery into compliance over the next five years will be approximately $50 million. We anticipate that, if the sale of the refinery is completed (see Note 2 of Notes to Consolidated Financial Statements), the purchaser would be responsible for these compliance expenditures. The actual costs incurred will depend on the final implementation plans.

On July 2, 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from our pipelines, pipeline systems, and pipeline facilities used in the movement of oil or petroleum products, during the period July 1, 1998 through July 2, 2001. In November 2001, we furnished our response. This matter has not become an enforcement proceeding. On March 11, 2004, the Department of Justice (DOJ) invited the new owner of the pipeline to enter into negotiations regarding alleged violations of the Clean Water Act and to sign a tolling agreement. No penalty has been assessed by the EPA; however, the DOJ stated in its letter that the maximum possible penalties were approximately $22 million for the alleged violations. It is anticipated that by providing additional clarification and through negotiations with the EPA and DOJ, that any proposed penalty will be reduced. We have indemnity obligations to the new owner related to this matter.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Stockholders of The Williams Companies, Inc.

We have audited the accompanying consolidated balance sheet of The Williams Companies, Inc. as of December 31, 2003 and 2002, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2003. Our audits also included the financial statement schedule listed in the Index to Exhibits in Exhibit 99.2. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of The Williams Companies, Inc. at December 31, 2003 and 2002, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects, the information set forth therein.

As explained in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted Emerging Issues Task Force Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (see third paragraph of "Energy commodity risk management and trading activities and revenues" section in Note 1) and Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (see last paragraph of "Property, plant and equipment" section in Note 1).

/s/ ERNST & YOUNG LLP

Tulsa, Oklahoma
February 18, 2004, except for the matter described in the
second paragraph in Note 2, as to which the date is
September 14, 2004, and except for Note 19, as to which the date is
November 2, 2004

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

	YEARS ENDED DECEMBER 31, 2003	2002	2001
	(MILLIONS, EXCEPT PER-SHARE AMOUNTS)		
Revenues:			
Power	$ 13,195.5	$ 56.2	$ 1,705.6
Gas Pipeline	1,368.3	1,301.2	1,243.1
Exploration & Production	779.7	860.4	603.9
Midstream Gas & Liquids	2,778.5	1,143.1	1,155.2
Other	72.0	124.1	319.3
Intercompany eliminations	(1,549.3)	(91.1)	(127.6)
Total revenues	16,644.7	3,393.9	4,899.5
Segment costs and expenses:			
Costs and operating expenses	14,989.7	1,934.3	2,111.2
Selling, general and administrative expenses	407.1	564.0	655.5
Other (income) expense -- net	(130.2)	240.1	(12.4)
Total segment costs and expenses	15,266.6	2,738.4	2,754.3
General corporate expenses	87.0	142.8	124.3
Operating income (loss):			
Power	145.3	(471.7)	1,294.6
Gas Pipeline	539.6	461.3	390.0
Exploration & Production	392.5	504.9	217.2
Midstream Gas & Liquids	309.4	177.9	183.0
Other	(8.7)	(16.9)	60.4
General corporate expenses	(87.0)	(142.8)	(124.3)
Total operating income	1,291.1	512.7	2,020.9
Interest accrued	(1,286.1)	(1,159.4)	(691.8)
Interest capitalized	45.5	27.3	36.9
Interest rate swap loss	(2.2)	(124.2)	-
Investing income (loss)	73.1	(113.2)	(172.6)
Minority interest in income and preferred returns of consolidated subsidiaries	(19.4)	(41.8)	(71.7)
Other income (expense) -- net	(26.1)	24.3	26.4
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	75.9	(874.3)	1,148.1
Provision (benefit) for income taxes	47.7	(277.2)	507.6
Income (loss) from continuing operations	28.2	(597.1)	640.5
Income (loss) from discontinued operations	240.9	(157.6)	(1,118.2)
Income (loss) before cumulative effect of change in accounting principles	269.1	(754.7)	(477.7)
Cumulative effect of change in accounting principles	(761.3)	-	-
Net loss	(492.2)	(754.7)	(477.7)
Preferred stock dividends	29.5	90.1	-
Loss applicable to common stock	$ (521.7)	$ (844.8)	$ (477.7)
Basic earnings (loss) per common share:			
Income (loss) from continuing operations	$ -	$ (1.33)	$ 1.29
Income (loss) from discontinued operations	.46	(.30)	(2.25)
Income (loss) before cumulative effect of change in accounting principles	.46	(1.63)	(.96)
Cumulative effect of change in accounting principles	(1.47)	-	-
Net loss	$ (1.01)	$ (1.63)	$ (.96)
Diluted earnings (loss) per common share:			
Income (loss) from continuing operations	$ -	$ (1.33)	$ 1.28
Income (loss) from discontinued operations	.46	(.30)	(2.23)
Income (loss) before cumulative effect of change in accounting principles	.46	(1.63)	(.95)
Cumulative effect of change in accounting principles	(1.47)	-	-
Net loss	$ (1.01)	$ (1.63)	$ (.95)

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED BALANCE SHEET

	December 31, 2003	December 31, 2002
	(DOLLARS IN MILLIONS, EXCEPT PER SHARE AMOUNTS)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,315.7	$ 1,650.4
Restricted cash	47.1	102.8
Restricted investments	93.2	-
Accounts and notes receivable less allowance of $112.2 ($111.8 in 2002)	1,613.2	2,387.1
Inventories	242.9	365.7
Energy risk management and trading assets	-	296.7
Derivative assets	3,166.8	5,024.3
Margin deposits	553.9	804.8
Assets of discontinued operations	441.3	1,297.3
Deferred income taxes	106.6	569.2
Other current assets and deferred charges	214.3	387.8
Total current assets	8,795.0	12,886.1
Restricted cash	159.8	188.1
Restricted investments	288.1	-
Investments	1,463.6	1,468.6
Property, plant and equipment -- net	11,734.0	11,698.2
Energy risk management and trading assets	-	1,821.6
Derivative assets	2,495.6	1,865.1
Goodwill	1,014.5	1,059.5
Assets of discontinued operations	345.1	3,268.8
Other assets and deferred charges	726.1	732.5
Total assets	$ 27,021.8	$ 34,988.5
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Notes payable	$ 3.3	$ 996.3
Accounts payable	1,228.0	1,864.0
Accrued liabilities	944.4	1,404.5
Liabilities of discontinued operations	95.7	550.2
Energy risk management and trading liabilities	-	244.4
Derivative liabilities	3,064.2	5,168.3
Long-term debt due within one year	935.2	1,080.8
Total current liabilities	6,270.8	11,308.5
Long-term debt	11,039.8	11,075.7
Deferred income taxes	2,453.4	3,353.6
Liabilities and minority interests of discontinued operations	-	1,264.5
Energy risk management and trading liabilities	-	680.9
Derivative liabilities	2,124.1	1,209.8
Other liabilities and deferred income	947.5	962.8
Contingent liabilities and commitments (Note 16)		
Minority interests in consolidated subsidiaries	84.1	83.7
Stockholders' equity:		
Preferred stock, $1 per share par value, 30 million shares authorized, 1.5 million issued in 2002	-	271.3
Common stock, $1 per share par value, 960 million shares authorized, 521.4 million issued in 2003, 519.9 million issued in 2002	521.4	519.9
Capital in excess of par value	5,195.1	5,177.2
Accumulated deficit	(1,426.8)	(884.3)
Accumulated other comprehensive income (loss)	(121.0)	33.8
Other	(28.0)	(30.3)
	4,140.7	5,087.6
Less treasury stock (at cost), 3.2 million shares of common stock in 2003 and 2002	(38.6)	(38.6)
Total stockholders' equity	4,102.1	5,049.0
Total liabilities and stockholders' equity	$ 27,021.8	$ 34,988.5

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

	PREFERRED STOCK	COMMON STOCK	CAPITAL IN EXCESS OF PAR VALUE	RETAINED EARNINGS (DEFICIT)	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	OTHER	TREASURY STOCK	TOTAL
	(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS)							
BALANCE, DECEMBER 31, 2000	$ --	$ 447.9	$2,473.9	$ 3,065.7	$ 28.2	$ (81.2)	$ (42.5)	$5,892.0
Comprehensive loss:								
Net loss -- 2001	--	--	--	(477.7)	--	--	--	(477.7)
Other comprehensive income:								
Net unrealized gains on cash flow hedges, net of reclassification adjustments	--	--	--	--	370.2	--	--	370.2
Net unrealized depreciation on marketable equity securities, net of reclassification adjustments......	--	--	--	--	(35.3)	--	--	(35.3)
Foreign currency translation adjustments.......................	--	--	--	--	(37.1)	--	--	(37.1)
Minimum pension liability adjustment	--	--	--	--	(2.2)	--	--	(2.2)
Total other comprehensive income								295.6
Total comprehensive loss								(182.1)
Issuance of common stock (38 million shares)............................	--	38.0	1,295.4	--	--	--	--	1,333.4
Issuance of common stock for acquisition of business (29.6 million shares)............................	--	29.6	1,206.1	--	--	--	--	1,235.7
Cash dividends -- Common stock ($.68 per share)	--	--	--	(341.0)	--	--	--	(341.0)
Stockholders' notes issued	--	--	--	--	--	(8.8)	--	(8.8)
Stockholders' notes repaid	--	--	--	--	--	6.3	--	6.3
Stock award transactions, including tax benefit (including 3.6 million common shares)......................	--	3.4	98.6	--	--	.7	2.8	105.5
Distribution of WilTel's common stock	--	--	--	(2,047.4)	21.3	18.0	--	(2,008.1)
Other	--	--	11.1	--	--	--	--	11.1
BALANCE, DECEMBER 31, 2001	--	518.9	5,085.1	199.6	345.1	(65.0)	(39.7)	6,044.0
Comprehensive loss:								
Net loss -- 2002	--	--	--	(754.7)	--	--	--	(754.7)
Other comprehensive loss:								
Net unrealized losses on cash flow hedges, net of reclassification adjustments......................	--	--	--	--	(298.9)	--	--	(298.9)
Net unrealized appreciation on marketable equity securities, net of reclassification adjustments......	--	--	--	--	4.6	--	--	4.6
Foreign currency translation adjustments........................	--	--	--	--	(.1)	--	--	(.1)
Minimum pension liability adjustment	--	--	--	--	(16.9)	--	--	(16.9)
Total other comprehensive loss								(311.3)
Total comprehensive loss								(1,066.0)
Issuance of 9.875 percent cumulative convertible preferred stock (1.5 million shares)....................	271.3	--	--	--	--	--	--	271.3
Cash dividends -- Common stock ($.42 per share)	--	--	--	(216.8)	--	--	--	(216.8)
Preferred stock($14.14 per share) ...	--	--	--	(20.8)	--	--	--	(20.8)
Issuance of equity of consolidated limited partnership...............	--	--	44.6	--	--	--	--	44.6
Beneficial conversion option on issuance of convertible preferred stock (Note 13)....................	--	--	69.4	(69.4)	--	--	--	--
FELINE PACS equity contract adjustment (Note 13)	--	--	(76.7)	--	--	--	--	(76.7)
Allowance for and repayments of stockholders' notes................	--	--	--	--	--	7.8	(1.3)	6.5
Stock award transactions, including tax benefit (including 1.2 million common shares)......................	--	1.0	33.1	--	--	.4	2.4	36.9
ESOP loan repayment	--	--	--	--	--	26.5	--	26.5
Other	--	--	21.7	(22.2)	--	--	--	(.5)
BALANCE, DECEMBER 31, 2002	271.3	519.9	5,177.2	(884.3)	33.8	(30.3)	(38.6)	5,049.0
Comprehensive loss:								
Net loss -- 2003	--	--	--	(492.2)	--	--	--	(492.2)
Other comprehensive loss:								
Net unrealized losses on cash flow								

hedges, net of reclassification adjustments.......................	--	--	--	--	(236.9)	--	--	(236.9)
Net unrealized depreciation on marketable equity securities, net of reclassification adjustments...	--	--	--	--	(7.4)	--	--	(7.4)
Foreign currency translation adjustments	--	--	--	--	77.0	--	--	77.0
Minimum pension liability adjustment	--	--	--	--	12.5	--	--	12.5
Total other comprehensive loss								(154.8)
Total comprehensive loss								(647.0)
Redemption of 9.875 percent cumulative convertible preferred stock (1.5 million shares)......................	(271.3)	--	--	--	--	--	--	(271.3)
Cash dividends -- Common stock ($.04 per share)	--	--	--	(20.8)	--	--	--	(20.8)
Preferred stock($20.14 per share) ...	--	--	--	(29.5)	--	--	--	(29.5)
Repayments of stockholders' notes	--	--	--	--	--	2.3	--	2.3
Stock award transactions, including tax benefit (including 1.5 million common shares).......................	--	1.5	17.9	--	--	--	--	19.4
BALANCE, DECEMBER 31, 2003	$ --	$ 521.4	$5,195.1	$(1,426.8)	$ (121.0)	$ (28.0)	$ (38.6)	$4,102.1

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(MILLIONS)		
OPERATING ACTIVITIES:			
Income (loss) from continuing operations	$ 28.2	$ (597.1)	$ 640.5
Adjustments to reconcile to cash provided (used) by operations:			
Depreciation, depletion and amortization	657.4	648.8	515.4
Provision (benefit) for deferred income taxes	65.3	(199.4)	322.3
Payments of guarantees and payment obligations related to WilTel	--	(753.9)	--
Provision for loss on investments, property and other assets	231.9	399.1	157.4
Net gain on dispositions of assets	(142.8)	(190.4)	(91.2)
Provision for uncollectible accounts:			
WilTel	--	268.7	188.0
Other	7.3	9.7	13.6
Minority interest in income and preferred returns of consolidated subsidiaries	19.4	41.8	71.7
Amortization and taxes associated with stock-based awards	27.1	31.2	22.4
Payment of deferred set-up fee and fixed rate interest on RMT note payable	(265.0)	--	--
Accrual for fixed rate interest included in RMT note payable	99.3	32.2	--
Amortization of deferred set-up fee and fixed rate interest on RMT note payable	154.5	110.9	--
Cash provided (used) by changes in current assets and liabilities:			
Restricted cash	(1.4)	(4.0)	--
Accounts and notes receivable	668.7	243.7	344.3
Inventories	88.6	85.6	254.9
Margin deposits	252.2	(633.4)	559.5
Other current assets and deferred charges	10.3	(262.7)	(2.3)
Accounts payable	(608.0)	(573.0)	(420.5)
Accrued liabilities	(387.1)	(261.2)	248.4
Changes in current and noncurrent derivative and energy risk management and trading assets and liabilities	(350.0)	579.5	(1,419.2)
Changes in noncurrent restricted cash	17.6	(104.1)	--
Other, including changes in noncurrent assets and liabilities	34.4	29.5	(37.8)
Net cash provided (used) by operating activities of continuing operations	607.9	(1,098.5)	1,367.4
Net cash provided by operating activities of discontinued operations	162.2	583.2	461.2
Net cash provided (used) by operating activities	770.1	(515.3)	1,828.6
FINANCING ACTIVITIES:			
Proceeds from notes payable	--	913.4	1,852.4
Payments of notes payable	(960.8)	(2,051.7)	(2,631.4)
Proceeds from long-term debt	2,006.5	3,481.5	3,377.1
Payments of long-term debt	(2,187.1)	(2,536.2)	(1,654.7)
Proceeds from issuance of common stock	1.2	5.2	1,388.5
Dividends paid	(53.3)	(230.8)	(341.0)
Proceeds from issuance of preferred stock	--	271.3	--
Repurchase of preferred stock	(275.0)	(135.0)	--
Net proceeds from issuance of preferred interests of consolidated subsidiaries	--	--	95.3
Redemption of our obligated mandatorily preferred securities of Trust holding only our indentures	--	--	(194.0)
Payments for debt issuance costs	(78.6)	(186.3)	(44.8)
Premiums paid on tender offer and early debt retirements	(57.7)	--	--
Payments/dividends to minority and preferred interests	(19.8)	(48.0)	(50.3)
Changes in restricted cash	67.9	(182.1)	--
Changes in cash overdrafts	(29.7)	28.4	(28.8)
Other -- net	(2.8)	(8.4)	(.1)
Net cash provided (used) by financing activities of continuing operations	(1,589.2)	(678.7)	1,768.2
Net cash provided (used) by financing activities of discontinued operations	(94.8)	524.7	1,584.2
Net cash provided (used) by financing activities	(1,684.0)	(154.0)	3,352.4
INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(956.0)	(1,662.0)	(1,457.1)
Proceeds from dispositions	603.9	549.1	28.4
Acquisitions of businesses (primarily property, plant and equipment), net of cash acquired	--	--	(1,291.6)
Purchases of investments/advances to affiliates	(150.4)	(308.7)	(568.3)
Purchases of restricted investments	(739.9)	--	--
Proceeds from sales of businesses	2,250.5	2,300.4	163.7
Proceeds from sale of restricted investments	351.8	--	--
Proceeds from dispositions of investments and other assets	128.6	273.0	243.9
Proceeds received on advances to affiliates	--	75.0	95.0
Proceeds received on sale of receivables from WilTel	--	180.0	--
Purchase of assets subsequently leased to seller	--	--	(276.0)
Other -- net	33.6	35.0	24.7

Net cash provided (used) by investing activities of continuing operations	1,522.1	1,441.8	(3,037.3)
Net cash used by investing activities of discontinued operations	(26.0)	(337.6)	(1,956.8)
Net cash provided (used) by investing activities	1,496.1	1,104.2	(4,994.1)
Cash of discontinued operations at spinoff	--	--	(96.5)
Increase in cash and cash equivalents	582.2	434.9	90.4
Cash and cash equivalents at beginning of year	1,736.0	1,301.1	1,210.7
Cash and cash equivalents at end of year*	$ 2,318.2	$ 1,736.0	$ 1,301.1

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* Includes cash and cash equivalents of discontinued operations of $2.5 million, $85.6 million and $60.7 million for 2003, 2002 and 2001, respectively.

See accompanying notes.

NOTE 1. DESCRIPTION OF BUSINESS, BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

DESCRIPTION OF BUSINESS

Operations of our company are located principally in the United States and are organized into the following reporting segments: Gas Pipeline, Exploration & Production, Midstream Gas & Liquids, and Power (formerly named Williams Energy Marketing & Trading Company).

Gas Pipeline is comprised primarily of two interstate natural gas pipelines as well as investments in natural gas pipeline-related companies. The Gas Pipeline operating segments have been aggregated for reporting purposes and include Northwest Pipeline, which extends from the San Juan Basin in northwestern New Mexico and southwestern Colorado to Oregon and Washington, and Transcontinental Gas Pipe Line (Transco), which extends from the Gulf of Mexico region to the northeastern United States.

Exploration & Production includes natural gas exploration, production and gas management activities primarily in the Rocky Mountain and Mid-Continent regions of the United States and in Argentina.

Midstream Gas & Liquids (Midstream) is comprised of natural gas gathering and processing and treating facilities in the Rocky Mountain and Gulf Coast regions of the United States, majority-owned natural gas compression and transportation facilities in Venezuela; and assets in Canada including a natural gas liquids extraction facility and a fractionation plant.

Power is an energy services provider that buys, sells, stores, and transports a full suite of energy-related commodities, including power, natural gas, crude oil, refined products and emission credits, primarily on a wholesale level. In June 2002, we announced our intent to exit the energy merchant business and reduce our financial commitment to the Power segment. As a result, Power initiated efforts to sell all or portions of its power, natural gas and crude and refined products portfolios and reduced its involvement in trading activities as defined in Statement of Financial Accounting Standard (SFAS) No. 115 "Accounting for Certain Investments in Debt and Equity Securities." However, Power still conducts limited trading activities and maintains contracts entered into for trading purposes. As the process to sell the portfolio continues, Power manages its activities to reduce risk, to generate cash and to fulfill contractual commitments.

OVERVIEW

In February 2003, we outlined our planned business strategy in response to the events that significantly impacted the energy sector and our company during late 2001 and much of 2002, including the collapse of Enron and the severe decline of the telecommunications industry. The plan focused on migrating to an integrated natural gas business comprised of a strong, but smaller, portfolio of natural gas businesses; reducing debt; and increasing our liquidity through asset sales, strategic levels of financing and reductions in operating costs. The plan was designed to address near-term and medium-term debt and liquidity issues, to de-leverage the company with the objective of returning to investment grade status, and to develop a balance sheet and cash flows capable of supporting and ultimately growing our remaining businesses. A component of our plan was to reduce risk and liquidity requirements of the Power segment while realizing the value of Power's portfolio. Another component of the plan consisted of selling all or parts of the Power business.

During 2003, we successfully executed the following critical components of our plan:

- Generated cash proceeds of approximately $3 billion from the sales of assets.

- Repaid $3.2 billion of debt through scheduled maturities and early extinguishment of debt and accessed the public debt markets available to us primarily to refinance $2 billion of higher cost debt.

- Sustained core business earnings capacity through completed system expansions at Gas Pipeline, continued drilling activity at Exploration & Production and continued investment in deepwater activities within Midstream.

- Continued rationalization of our cost structure, including a 28 percent reduction in selling, general and administrative costs of continuing operations and a 39 percent reduction in general corporate expenses.

Through these efforts, we satisfied key liquidity issues facing us in 2003, including the early repayment of the Williams Production RMT Company (RMT) note payable of approximately $1.15 billion (including certain contractual fees and deferred interest). Additionally, we completed tender offers that prepaid approximately $721 million of the $1.4 billion of our senior unsecured 9.25 percent notes that mature in first-quarter 2004.

We are pursuing a strategy of exiting the Power business. However, market conditions have contributed to the difficulty of, and could delay, full, immediate exit from this business. In 2003, we generated in excess of $600 million from the sale, termination or liquidation of Power contracts and assets. During the year, we continued to manage our portfolio to reduce risk, to generate cash and to fulfill contractual commitments. We are also pursuing our goal to resolve the remaining legal and regulatory issues associated with the business.

During 2003, we engaged financial advisors to assist and advise with efforts to exit the Power business. Because market conditions may change and we cannot determine the impact of this on a buyer's point of view, amounts ultimately received in any portfolio sale, contract liquidation or realization may be significantly different from the estimated economic value or carrying values reflected in the Consolidated Balance Sheet. In addition, tolling agreements are not derivatives and thus have no carrying value in the Consolidated Balance Sheet pursuant to the application of Emerging Issues Task Force (EITF) Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities," (EITF 02-3). Based on current market conditions certain of these agreements are forecasted to realize significant future losses. It is possible that we may sell contracts for less than their carrying value or enter into agreements to terminate certain obligations, either of which could result in significant future loss recognition or reductions of future cash flows.

Results for 2003 include approximately $117 million of revenue related to the correction of the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001. This matter was initially disclosed in our Form 10-Q for the second quarter of 2003. Income from continuing operations before income taxes and cumulative effect of change in accounting principles in 2003 was $51.6 million. Absent the corrections, we would have reported a pretax loss from continuing operations in 2003. Approximately $83 million of this revenue relates to a correction of net energy trading assets for certain derivative contract terminations occurring in 2001. The remaining $34 million relates to net gains on certain other derivative contracts entered into in 2002 and 2001 that we now believe should not have been deferred as a component of other comprehensive income due to the incorrect designation of these contracts as cash flow hedges. Our management, after consultation with our independent auditor, concluded that the effect of the previous accounting treatment was not material to 2003 and prior periods and the trend of earnings.

Entering 2004, our plan is to focus on the following objectives:

- sustain solid core business performance, including increased capital allocation to Exploration & Production activities;

- continue reduction of debt, including scheduled maturities and early retirements, and selective refinancing of certain instruments; and

- maintain investment discipline.

Key execution steps include the completion of planned asset sales, which are estimated to generate proceeds of approximately $800 million in 2004, additional reductions of our SG&A costs, the replacement of our cash-collateralized letter of credit and revolver facility with facilities that do not encumber cash and continuing efforts to exit from the power business.

BASIS OF PRESENTATION

In accordance with the provisions related to discontinued operations within 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, financial position and cash flows of the following components as discontinued operations (see Note 2):

- Kern River Gas Transmission (Kern River), previously one of Gas Pipeline's segments;
- two natural gas liquids pipeline systems, Mid-American Pipeline and Seminole Pipeline, previously part of the Midstream segment;
- Central natural gas pipeline, previously one of Gas Pipeline's segments;
- retail travel centers concentrated in the Midsouth, part of the previously reported Petroleum Services segment;
- refining and marketing operations in the Midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;
- Texas Gas Transmission Corporation, previously one of Gas Pipeline's segments;
- natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment;
- bio-energy operations, part of the previously reported Petroleum Services segment;
- our general partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;
- the Colorado soda ash mining operations, part of the previously reported International segment;
- certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream segment;
- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment;
- Gulf Liquids New River Project LLC, previously part of the Midstream segment; and
- our straddle plants in western Canada, previously part of the Midstream segment.

Additionally, the results of operations and cash flows of WilTel Communications (WilTel), formerly Williams Communications, are reflected in discontinued operations in the accompanying financial statements.

Unless otherwise indicated, the information in the Notes to the Consolidated Financial Statements relates to our continuing operations. We expect that other components of our business may be classified as discontinued operations in the future as the sales of those assets occur.

We have restated all segment information in the Notes to the Consolidated Financial Statements for all prior periods presented to reflect the changes noted above.

We have also reclassified certain prior year amounts to conform to current year classifications.

In 2001, through two transactions, we acquired all of the outstanding stock of Barrett Resources Corporation (Barrett). On June 11, 2001, we acquired 50 percent of Barrett's outstanding common stock in a cash tender offer totaling approximately $1.2 billion. We acquired the remaining 50 percent of Barrett's outstanding common stock on August 2, 2001, through a merger by exchanging each remaining share of Barrett common stock for 1.767 shares of our common stock for a total of approximately 30 million shares of our common stock valued at $1.2 billion.

The unaudited pro forma net loss for 2001, if the purchase of 100 percent of Barrett occurred at the beginning of that year, was $396 million, or $.76 loss per diluted share. Pro forma financial information is not necessarily indicative of results of operations that would have occurred if the acquisition had occurred at the beginning of that year or of future results of operations of the combined companies.

The estimated fair values of the significant assets acquired and liabilities assumed at August 2, 2001, the date of acquisition, were:

- Current assets -- $127.6 million
- Property, plant and equipment -- $2,520.4 million
- Goodwill and other assets -- $1,114.5 million
- Current liabilities -- $171.6 million
- Long-term debt -- $312.1 million
- Deferred income taxes -- $634.7 million
- Other non-current liabilities -- $127.1 million

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation

The consolidated financial statements include the accounts of our corporate parent and our majority-owned subsidiaries and investments. We account for companies in which we and our subsidiaries own 20 percent to 50 percent of the voting common stock, or otherwise exercise significant influence over operating and financial policies of the company, under the equity method.

Use of estimates

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.

Estimates and assumptions which, in the opinion of management, are significant to the underlying amounts included in the financial statements and for which it would be reasonably possible that future events or information could change those estimates include:

- impairment assessments of long-lived assets and goodwill;
- litigation-related contingencies;
- valuations of energy contracts, including energy-related contracts;
- environmental remediation obligations;
- realization of deferred income tax assets;
- Gas Pipeline and Power revenues subject to refund; and
- valuation of Exploration & Production's reserves.

These estimates are discussed further throughout the accompanying notes.

Cash and cash equivalents

Cash and cash equivalents include demand and time deposits, certificates of deposit and other marketable securities with maturities of three months or less when acquired.

Restricted cash and investments

Restricted cash within current assets consists primarily of collateral as required by certain borrowings by our Venezuelan operations and letters of credit. Restricted cash within noncurrent assets consists primarily of collateral in support of surety bonds underwritten by an insurance company, the RMT term loan B (see Note 11), certain borrowings by our Venezuelan operations and letters of credit. We do not expect this cash to be released within the next twelve months. The current and noncurrent restricted cash is primarily invested in short-term money market accounts with financial institutions and an insurance company as well as treasury securities.

Both short-term and long-term restricted investments consist of short-term U.S. Treasury securities as required under the $800 million revolving and letter of credit facility (see Note 11). These securities are purchased and sold based on the balance required in the collateral account. Therefore, these securities are accounted for as "available-for-sale." These securities are marked to market with the unrealized holding gains and losses included in Other Comprehensive Income, until realized (see Note 18). Realized gains or losses are reclassified into earnings and based on specific identification of the securities sold.

The classification of restricted cash and investments is determined based on the expected term of the collateral requirement and not necessarily the maturity date of the underlying securities.

Accounts receivable

Accounts receivable are carried on a gross basis, with no discounting, less the allowance for doubtful accounts. No allowance for doubtful accounts is recognized at the time the revenue, which generates the accounts receivable, is recognized. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial conditions of the customers and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Interest income related to past due accounts receivable is recognized at the time full payment is received or collectibility is assured. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted.

Inventory valuation

Prior to the EITF reaching a consensus on EITF 02-3 on October 25, 2003 (see Energy commodity risk management and trading activities and revenues), we stated inventories at cost, which were not in excess of market, except for certain assets held for energy risk management by Power and Midstream which were stated at fair value. We stated all inventories purchased after October 25, 2003 at cost in accordance with Issue 02-3. For inventories held for energy risk management purposes purchased on or before October 25, 2002, we included the amount by which fair value exceeded cost in a cumulative effect of a change in accounting principle. Beginning on January 1, 2003, we stated all inventories at cost, which is not in excess of market. We determined the cost of certain natural gas inventories held by Transco using the last-in, first-out (LIFO) cost method; and we determined the cost of the remaining inventories primarily using the average-cost method or market, if lower.

Property, plant and equipment

Property, plant and equipment is recorded at cost. We base the carrying value of these assets on estimates, assumptions and judgments relative to capitalized costs, useful lives and salvage values. As regulated entities, Northwest Pipeline and Transco provide for depreciation using the straight-line method at FERC prescribed rates. Depreciation of general plant is provided on a group basis at straight-line rates. Depreciation rates used for major regulated gas plant facilities at December 31, 2003, 2002, and 2001 are as follows:

CATEGORY OF PROPERTY	2003	2002	2001
Gathering facilities............	0% - 3.80%	0% - 3.80%	2.60% - 3.80%
Storage facilities..............	1.05% - 2.50%	1.05% - 2.50%	1.05% - 2.50%
Onshore transmission facilities..	2.35% - 5.00%	2.35% - 5.00%	2.35% - 5.00%
Offshore transmission facilities.	0.85% - 1.50%	0.85% - 1.50%	1.50%

Depreciation for non-regulated entities is provided primarily on the straight-line method over estimated useful lives except as noted below regarding oil and gas exploration and production activities. The estimated useful lives are as follows.

CATEGORY OF PROPERTY	ESTIMATED USEFUL LIVES
	(IN YEARS)
Natural Gas Gathering and Processing Facilities....	10 to 40
Power Generation Facilities........................	15 to 30
Transportation Equipment...........................	3 to 30
Building and Improvements..........................	10 to 45
Right of Way.......................................	4 to 40
Office Furnishings & Computers.....................	3 to 20

Gains or losses from the ordinary sale or retirement of property, plant and equipment for regulated pipelines are credited or charged to accumulated depreciation; other gains or losses are recorded in net income (loss).

Oil and gas exploration and production activities are accounted for under the successful efforts method of accounting. Costs incurred in connection with the drilling and equipping of exploratory wells are capitalized as incurred. If proved reserves are not found, such costs are charged to expense. Other exploration costs, including lease rentals, are expensed as incurred. All costs related to development wells, including related production equipment and lease acquisition costs, are capitalized when incurred. Unproved properties are evaluated annually, or as conditions warrant, to determine any impairment in carrying value. Depreciation, depletion and amortization are provided under the units of production method on a field basis.

Proved properties, including developed and undeveloped, and costs associated with probable reserves, are assessed for impairment using estimated future cash flows on a field basis. Estimating future cash flows involves the use of complex judgments such as estimation of the proved and probable oil and gas reserve quantities, risk associated with the different categories of oil and gas reserves, timing of development and production, expected future commodity prices, capital expenditures and production costs.

Effective January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." This Statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. As required by the new standard, we recorded liabilities equal to the present value of expected future asset retirement obligations at January 1, 2003. The obligations relate to producing wells, offshore platforms, underground storage caverns and gas gathering well connections. At the end of the useful life of each respective asset, we are legally obligated to plug both producing wells and storage caverns and remove any related surface equipment, to dismantle offshore platforms, and to cap certain gathering pipelines at the wellhead connection and remove any related surface equipment. The liabilities are partially offset by increases in property, plant and equipment, net of accumulated depreciation, recorded as if the provisions of the Statement had been in effect at the date the obligation was incurred. As a result of the adoption of SFAS No. 143, we recorded a long-term liability of $33.4 million; property, plant and equipment, net of accumulated depreciation, of $24.8 million and a credit to earnings of $1.2 million (net of a $.1 million provision for income taxes) reflected as a cumulative effect of a change in accounting principle. We also recorded a $9.7 million regulatory asset for retirement costs of dismantling offshore platforms expected to be recovered through regulated rates. In connection with adoption of SFAS No. 143, we changed our method of accounting to include salvage value of equipment related to producing wells in the calculation of depreciation. The impact of this change is included in the amounts discussed above. We have not recorded liabilities for pipeline transmission assets, processing and refining assets, and gas gathering systems pipelines. A reasonable estimate of the fair value of the retirement obligations for these assets cannot be made as the remaining life of these assets is not currently determinable. If the Statement had been adopted at the beginning of 2002, the impact to our income from continuing operations and net income would have been immaterial. There would have been no impact on earnings per share.

Goodwill

Goodwill represents the excess of cost over fair value of assets of businesses acquired. Beginning January 1, 2002, the impairment of goodwill and other intangible assets is measured pursuant to the guidelines of SFAS No. 142, "Goodwill and Other Intangible Assets". Goodwill is evaluated for impairment by first comparing our management's estimate of the fair value of a reporting unit with its carrying value, including goodwill. If the carrying value exceeds its fair value, a computation of the implied fair value of the goodwill is compared with its related carrying value. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in the amount of the excess.

When a reporting unit is sold or classified as held for sale, any goodwill of that reporting unit is included in its carrying value for purposes of determining any impairment or gain/loss on sale. If a portion of a reporting unit with goodwill is sold or classified as held for sale and that asset group represents a business, a portion of the reporting unit's goodwill is allocated to and included in the carrying value of that asset group. Except for Bio-energy, Alaska Retail, Williams Energy Partners and the Travel Centers, none of the operations sold during 2003 or classified as held for sale at December 31, 2003 represented reporting units with goodwill or businesses within reporting units to which goodwill was required to be allocated.

Judgments and assumptions are inherent in our management's estimate of undiscounted future cash flows used to determine the estimate of the reporting unit's fair value. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the financial statements.

In accordance with SFAS No. 142, approximately $1 billion of goodwill acquired subsequent to June 30, 2001, in the acquisition of Barrett, was not amortized in 2001. Beginning January 1, 2002, all goodwill is no longer amortized, but is tested annually for impairment. Application of the nonamortization provisions of SFAS No. 142 did not materially impact the comparability of the Consolidated Statement of Operations. Exploration & Production's goodwill was approximately $1 billion at December 31, 2003 and 2002.

Treasury stock

Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as treasury stock. Gains and losses on the subsequent reissuance of shares are credited or charged to capital in excess of par value using the average-cost method.

Energy commodity risk management and trading activities and revenues

Prior to 2003, we, through Power and the natural gas liquids trading operations (reported within the Midstream segment), had energy commodity risk management and trading operations that entered into energy and energy-related contracts to provide price-risk management services to our third-party customers. These contracts involved power, natural gas, refined products, natural gas liquids and crude oil. Prior to the adoption of EITF 02-3, we valued all energy and energy-related contracts used in energy commodity risk management and trading activities at fair value in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." Energy contracts included the following:

- forward contracts,
- futures contracts,
- option contracts,
- swap agreements,
- certain physical commodity inventories, and
- short-and long-term purchase and sale commitments, which involve physical delivery of an energy commodity.

Energy-related contracts included the following:

- power tolling contracts,
- full requirements contracts,
- load serving contracts,
- storage contracts,
- transportation contracts, and
- transmission contracts.

In addition, we entered into interest rate swap agreements and credit default swaps to manage the interest rate and credit risk in our energy trading portfolio. Prior to 2003, we recorded these energy and energy-related contracts and credit default swap agreements, with the exception of physical trading commodity inventories, in current and noncurrent energy risk management and trading assets and energy risk management and trading liabilities in the Consolidated Balance Sheet. We based the classification of current versus noncurrent on the timing of expected future cash flows. In accordance with SFAS No. 133 and Issue No. 98-10, we recognized the net change in fair value of these contracts representing unrealized gains and losses in income currently. We also recorded the net change in fair value as revenues in the Consolidated Statement of Operations. Power and the natural gas liquids trading operations, reported their trading operations' physical sales transactions net of the related purchase costs, consistent with fair value accounting for such trading activities. The accounting for energy-related contracts required us to assess whether certain of these contracts were executory service arrangements or leases pursuant to SFAS No. 13, "Accounting for Leases." As a result, we assessed each of our energy-related contracts and made the determination based on the substance of each contract focusing on factors such as 1) physical and operational control of the related asset, 2) risks and rewards of owning, operating and maintaining the related asset and 3) other contractual terms. See Recent accounting standards section within this Note for recent developments regarding guidance determining whether an arrangement contains a lease.

As discussed in the Inventory valuation section of this note, the EITF reached a consensus on Issue No. 02-3 on October 25, 2002. This issue rescinded EITF Issue No. 98-10. As a result of the rescission, in 2003, we no longer account for 1) energy trading contracts that are derivatives as defined in SFAS No. 133 and 2) commodity trading inventories at fair value. The consensus was applicable for fiscal periods beginning after December 15, 2002, except for physical trading commodity inventories purchased after October 25, 2002. Issue No. 02-3 prohibited us from reporting physical trading commodity inventories purchased after October 25, 2002 at fair value. We applied the consensus effective January 1, 2003 and reported the initial application as a cumulative effect of a change in accounting principle. The effect of initially applying the consensus reduced net income by $762.5 million, net of a $471.4 million benefit for income taxes. The charge primarily consisted of the fair value of power tolling, load serving, transportation and storage contracts. These contracts did not meet the definition of a derivative and thus are no longer reported at fair value. After January 1, 2003, these contracts were accounted for under the accrual basis of accounting. The charge also included the amount by which the December 31, 2002 fair value of physical trading commodity inventories exceeded cost. We continued to carry derivatives at fair value in 2003. See further discussion on derivative assets and liabilities in the Derivative instruments and hedging activities, including interest rate swaps section within this Note.

Prior to 2003, we determined the fair value of energy and energy-related contracts based on the nature of the transaction and the market in which transactions were executed. We executed certain transactions in exchange-traded or over-the-counter markets for which quoted prices in active periods existed. We executed other transactions in markets or periods in which quoted prices were not available. Quoted market prices for varying periods in active markets were readily available for valuing forward contracts, futures contracts, swap agreements and purchase and sales transactions in the commodity markets in which Power and the natural gas liquids trading operations transacted. Market data in active periods was also available for interest rate transactions, which affected the trading portfolio. For contracts or transactions that extended into periods for which actively quoted prices were not available, Power and the natural gas liquids trading operations estimated energy commodity prices in the illiquid periods by incorporating information obtained from commodity prices in actively quoted markets, prices in less active markets, prices reflected in current transactions and market fundamental analysis. For contracts where quoted market prices were not available, primarily transportation, storage, full requirements, load serving, transmission and power tolling contracts (energy-related contracts), Power estimated fair value using proprietary models and other valuation techniques that reflected the best information available under the circumstances. In situations where Power had received current information from negotiation activities with potential buyers of these contracts, Power considered this information in the determination of the fair value of the contract. The valuation techniques used when estimating fair value for energy-related contracts incorporated the following:

- option pricing theory,
- statistical and simulation analysis,
- present value concepts incorporating risk from uncertainty of the timing and amount of estimated cash flows, and
- specific contractual terms.

In estimating fair value, Power also assumed liquidation of the positions in an orderly manner over a reasonable period of time in a transaction between a willing buyer and seller.

These valuation techniques for tolling contracts, full requirements contracts and other non-derivative energy-related contracts utilized factors such as the following:

- quoted energy commodity market prices,
- estimates of energy commodity market prices in the absence of quoted market prices,
- volatility factors underlying the positions,
- estimated correlation of energy commodity prices, contractual volumes, and estimated volumes under option and other arrangements,
- liquidity of the market in which the contract was transacted, and
- a risk-free market discount rate.

Fair value also reflected a risk premium that market participants would consider in their determination of fair value. Regardless of the method for which fair value was determined, we considered the risk of non-performance and credit considerations of the counterparty in estimating the fair value of all contracts. We adjusted the estimates of fair value as assumptions changed or as transactions became closer to settlement and enhanced estimates become available.

The fair value of our trading portfolio was continually subject to change due to changing market conditions and changing trading portfolio positions. In 2002, determining fair value for these contracts also involved complex assumptions including estimating natural gas and power market prices in illiquid periods and markets, estimating market volatility and liquidity and correlation of natural gas and power prices, evaluating risk arising from uncertainty inherent in estimating cash flows and estimates regarding counterparty performance and credit considerations. Changes in valuation methodologies or the underlying assumptions could result in significantly different fair values.

Derivative instruments and hedging activities, including interest rate swaps

In 2002, we presented Power and Midstream's derivative and non-derivative trading assets on the Consolidated Balance Sheet in energy commodity risk management and trading activities. All other derivatives were presented in current assets, other assets and deferred charges, accrued liabilities and other liabilities and deferred income in the Consolidated Balance Sheet as of December 31, 2002. After the adoption of EITF 02-3 on January 1, 2003, we recorded all derivatives in current and noncurrent derivative assets and current and noncurrent derivative liabilities. We based the classification of current versus noncurrent on the timing of expected future cash flows.

Derivative instruments held by us consist primarily of futures contracts, swap agreements, forward contracts and option contracts. We execute most of these transactions in exchange-traded or over-the-counter markets for which quoted prices in active periods exist. For contracts with lives exceeding the time period for which quoted prices were available, we determine fair value by estimating commodity prices during the illiquid periods. We estimate commodity prices during illiquid periods by incorporating information obtained from commodity prices in actively quoted markets, prices reflected in current transactions and market fundamental analysis.

In first-quarter 2002, we began managing a portion of our interest rate risk on an enterprise basis by the corporate parent. The more significant of these risks relates to Power's trading and non-trading portfolio. To facilitate the management of the risk, our entities enter into derivative instruments (usually swaps) with the corporate parent. The level, term and nature of derivative instruments entered into with external parties are determined by the corporate parent. Power enters into intercompany interest rate swaps with the corporate parent, the effect of which is included in Power's segment revenues and segment profit (loss) as shown in the reconciliation within the segment disclosures (see Note 19). The results of interest rate swaps with external counterparties are shown as interest rate swap loss in the Consolidated Statement of Operations below operating income (loss).

The accounting for changes in the fair value of all derivatives depends upon whether we have designated them in a hedging relationship and, further, on the type of hedging relationship. To qualify for designation in a hedging relationship, specific criteria have to be met and the appropriate documentation maintained. We establish hedging relationships pursuant to our risk management policies. We initially and regularly evaluate the hedging relationships to determine whether they were expected to be, and remain, highly effective hedges. If a derivative ceases to be a highly effective hedge, hedge accounting is discontinued prospectively, and future changes in the fair value of the derivative are recognized in earnings each period.

For derivatives designated as a hedge of a recognized asset or liability or an unrecognized firm commitment (fair value hedges), we recognize the changes in the fair value of the derivative as well as changes in the fair value of the hedged item attributable to the hedged risk each period in earnings. If we terminate a firm commitment designated as the hedged item in a fair value hedge or it otherwise no longer qualifies as the hedged item, we recognize any asset or liability previously recorded as part of the hedged item currently in earnings.

For derivatives designated as a hedge of a forecasted transaction or of the variability of cash flows related to a recognized asset or liability (cash flow hedges), the effective portion of the change in fair value of the derivative is reported in other comprehensive income and reclassified into earnings in the period in which the hedged item affects earnings. Amounts excluded from the effectiveness calculation and any ineffective portion of the change in fair value of the derivative are recognized currently in earnings. Gains or losses deferred in accumulated other comprehensive income associated with terminated derivatives, derivatives that cease to be highly effective hedges and cash flow hedges that have been otherwise discontinued remain in accumulated other comprehensive income until the hedged item affects earnings or it is probable that the hedged item will not occur by the end of the originally specified time period or within two months thereafter. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. When it is probable the forecasted transaction will not occur, any gain or loss deferred in accumulated other comprehensive income is recognized in earnings at that time.

For derivatives held for trading and non-trading purposes not designated as a hedge, we reported changes in fair value currently in earnings. As discussed in the Description of business section of this Note, in 2003, we are no longer significantly engaged in trading activities. We now primarily enter into derivative contracts to reduce risk associated with our assets and non-derivative energy-related contracts, such as tolling, full requirements, storage and transportation contracts. However, we still maintain certain derivatives entered into for trading purposes. In Issue No. 02-3, the EITF reached a consensus that gains and losses on derivative instruments within the scope of SFAS No. 133 should be shown net in the income statement if the derivative instruments are held for trading purposes. On July 31, 2003, the EITF reached a consensus on Issue No. 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes as Defined in Issue No. 02-3 Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." In this issue, the EITF concluded that determining whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported in the income statement on a gross or net basis is a matter of judgment that depended on the relevant facts and circumstances. Applying these two consensuses, we report unrealized gains and losses on all derivative contracts not designated as hedges on a net basis in the Consolidated Statement of Operations. We also report realized gains and losses on all derivative contracts not designated as hedges that settled financially on a net basis. We apply the indicators provided in Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" to determine the proper treatment for derivative and non-derivative contracts not designated as hedges that resulted in physical delivery. In accordance with Issue No. 99-19, we account for realized revenues and purchase costs for all contracts that result in physical delivery on a gross basis in the Consolidated Statement of Operations. EITF 02-3 and Issue No. 03-11 did not require restatement of prior year amounts.

In the second quarter of 2003, we elected the normal purchases and normal sales exception available under SFAS No. 133 on certain derivative contracts held by our Power segment. We reflected these contracts in current and noncurrent derivative assets and liabilities at their fair value on the date of the election less the portion of that fair value allocable to previous settlement periods.

On January 1, 2001, we recorded a cumulative effect of an accounting change associated with the adoption of SFAS No. 133, as amended, to record all derivatives at fair value. The cumulative effect of the accounting change was not material to net income (loss), but resulted in a $95 million reduction of other comprehensive income (net of income tax benefits of $59 million) related to derivatives which hedge the variable cash flows of certain forecasted energy commodity transactions.

Gas pipeline revenues

Revenues for sales of products are recognized in the period of delivery, and revenues from the transportation of gas are recognized in the period the service is provided. Gas Pipeline is subject to Federal Energy Regulatory Commission (FERC) regulations and, accordingly, certain revenues collected may be subject to possible refunds upon final orders in pending rate cases. Gas Pipeline records estimates of rate refund liabilities considering Gas Pipeline and other third-party regulatory proceedings, advice of counsel and estimated total exposure, as discounted and risk weighted, as well as collection and other risks.

Revenues, other than gas pipeline and energy commodity risk management and trading activities

Revenues generally are recorded when services are performed or products have been delivered.

Additionally, revenues from the domestic production of natural gas in properties for which Exploration & Production has an interest with other producers are recognized based on the actual volumes sold during the period. Any differences between volumes sold and entitlement volumes, based on Exploration & Production's net working interest, which are determined to be non-recoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are not significant.

Impairment of long-lived assets and investments

We evaluate the long-lived assets of identifiable business activities for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such assets may not be recoverable. Beginning January 1, 2002, the impairment evaluation of tangible long-lived assets is measured pursuant to the guidelines of SFAS No. 144. When an indicator of impairment has occurred, we compare our management's estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred. We apply a probability-weighted approach to consider the likelihood of different cash flow assumptions and possible outcomes including selling in the near term or holding for the remaining estimated useful life. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

For assets identified to be disposed of in the future and considered held for sale in accordance with SFAS No. 144, we compare the carrying value to the estimated fair value less the cost to sell to determine if recognition of an impairment is required. Until the assets are disposed of, the estimated fair value, which includes estimated cash flows from operations until the assumed date of sale, is redetermined when related events or circumstances change.

We evaluate our investments for impairment when events or changes in circumstances indicate, in our management's judgement, that the carrying value of such investments may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, we compare our estimate of fair value of the investment to the carrying value of the investment to determine whether an impairment has occurred. If the estimated fair value is less than the carrying value and we consider the decline in value to be other than temporary, the excess of the carrying value over the fair value is recognized in the financial statements as an impairment.

Judgments and assumptions are inherent in our management's estimate of undiscounted future cash flows used to determine recoverability of an asset and the estimate of an asset's fair value used to calculate the amount of impairment to recognize. Additionally, our management's judgment is used to determine the probability of sale with respect to assets considered for disposal pursuant to our announced strategy of selling assets as a significant source of liquidity. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the financial statements.

Capitalization of interest

We capitalize interest on major projects during construction. Interest is capitalized on borrowed funds and, where regulation by the FERC exists, on internally generated funds. The rates used by regulated companies are calculated in accordance with FERC rules. Rates used by unregulated companies are based on the average interest rate on debt. Interest capitalized on internally generated funds, as permitted by FERC rules, is included in non-operating other income (expense) -- net.

Employee stock-based awards

Employee stock-based awards are accounted for under Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees" and related interpretations. Fixed-plan common stock options generally do not result in compensation expense because the exercise price of the stock options equals the market price of the underlying stock on the date of grant. The plans are described more fully in Note 14. The following table illustrates the effect on net loss and loss per share if we had applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation."

	YEARS ENDED DECEMBER 31,		
	2003	2002	2001
	(DOLLARS IN MILLIONS)		
Net loss, as reported	$ (492.2)	$ (754.7)	$ (477.7)
Add: Stock-based employee compensation expense included in the Consolidated Statement of Operations, net of related tax effects	18.7	19.1	13.6
Deduct: Total stock based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(31.6)	(34.5)	(24.7)
Pro forma net loss	$ (505.1)	$ (770.1)	$ (488.8)
Loss per share:			
Basic -- as reported	$ (1.01)	$ (1.63)	$ (.96)
Basic -- pro forma	$ (1.03)	$ (1.66)	$ (.98)
Diluted -- as reported	$ (1.01)	$ (1.63)	$ (.95)
Diluted -- pro forma	$ (1.03)	$ (1.66)	$ (.98)

Pro forma amounts for 2003 include compensation expense from awards of our company stock made in 2003, 2002 and 2001. Also included in the 2003 pro forma expense is $2 million of incremental expense associated with a stock option exchange program (see Note 14). Pro forma amounts for 2002 include compensation expense from awards made in 2002 and 2001 and from certain awards made in 1999. Pro forma amounts for 2001 include compensation expense from awards made in 2001 and from certain awards made in 1999.

Since compensation expense from stock options is recognized over the future years' vesting period for pro forma disclosure purposes and additional awards are generally made each year, pro forma amounts may not be representative of future years' amounts.

Income taxes

We include the operations of our subsidiaries in our consolidated tax return. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of our assets and liabilities. Our management's judgment and income tax assumptions are used to determine the levels, if any, of valuation allowances associated with deferred tax assets.

Earnings (loss) per share

Basic earnings (loss) per share is based on the sum of the weighted average number of common shares outstanding and issuable restricted and vested deferred shares. Diluted earnings (loss) per share includes any dilutive effect of stock options, unvested deferred shares and, for applicable periods presented, convertible preferred stock and convertible debt, unless otherwise noted.

Foreign currency translation

Certain of our foreign subsidiaries and equity method investees use their local currency as their functional currency. These foreign currencies include the Canadian dollar, British pound and Euro. Assets and liabilities of certain foreign subsidiaries and equity investees are translated at the spot rate in effect at the applicable reporting date, and the combined statements of operations and our share of the results of operations of our equity affiliates are translated into the U.S. dollar at the average exchange rates in effect during the applicable period. The resulting cumulative translation adjustment is recorded as a separate component of other comprehensive income (loss).

Transactions denominated in currencies other than the functional currency are recorded based on exchange rates at the time such transactions arise. Subsequent changes in exchange rates result in transactions gains and losses which are reflected in the Consolidated Statement of Operations.

Issuance of equity of consolidated subsidiary

Sales of common stock by a consolidated subsidiary are accounted for as capital transactions with the adjustment to capital in excess of par value. No gain or loss is recognized on these transactions.

Securitizations and transfers of financial instruments

Through July 2002, we had agreements to sell, on an ongoing basis, certain of our trade accounts receivable through revolving securitization structures under which we retained servicing responsibilities as well as a subordinate interest in the transferred receivables. These agreements expired in July 2002 and were not renewed. We accounted for the securitization of trade accounts receivable in accordance with SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." As a result, the related receivables were removed from the Consolidated Balance Sheet and a retained interest was recorded for the amount of receivables sold in excess of cash received.

We determined the fair value of our retained interests based on the present value of future expected cash flows using our management's best estimate of various factors, including credit loss experience and discount rates commensurate with the risks involved. These assumptions were updated periodically based on actual results, thus the estimated credit loss and discount rates utilized were materially consistent with historical performance. The fair value of the servicing responsibility was estimated based on internal costs, which approximate market. Costs associated with the sale of receivables are included in nonoperating other income (expense) -- net in the Consolidated Statement of Operations.

RECENT ACCOUNTING STANDARDS

The FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." Under this Statement, a liability for a cost associated with an exit or disposal activity is recognized at fair value when the liability is incurred rather than at the date of an entity's commitment to an exit plan. The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002; hence, initial adoption of this Statement on January 1, 2003, did not have any impact on our results of operations or financial position.

The FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation -- Transition and Disclosure," which is effective for fiscal years ending after December 15, 2002. SFAS No. 148 amends SFAS No. 123 to permit two additional transition methods for a voluntary change to the fair value based method of accounting for stock-based employee compensation from the intrinsic method under APB No. 25. The prospective method of transition under SFAS No. 123 is an option to the entities that adopt the recognition provisions under this statement in a fiscal year beginning before December 15, 2003. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements concerning the method of accounting used for stock-based employee compensation and the effects of that method on reported results of operations. Under this statement, pro forma disclosures are required in a specific tabular format in the "Summary of Significant Accounting Policies." We have applied the disclosure requirements of this statement effective December 31, 2002. The adoption had no effect on our consolidated financial position or results of operations. We continue to account for our stock-based compensation plans under APB Opinion No. 25. See Employee stock-based awards. FASB has announced it will be issuing an Exposure Draft on equity-based compensation. In deliberations on this matter, the FASB has concluded that equity-based compensation awards to employees results in an expense to the employer that should be recognized in the income statement.

The FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." This Interpretation requires the fair value of guarantees issued or modified after December 31, 2002, be initially recognized by the guarantor at the inception of the guarantee, and expands the disclosure requirements for guarantees. Initial adoption of this Interpretation did not have any impact on our results of operations or financial position. The expanded disclosure requirements have been presented in the Notes to Consolidated Financial Statements.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities." The Interpretation defines a variable interest entity (VIE) as an entity in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. The investments or other interests that will absorb portions of the VIE's expected losses if they occur or receive portions of the VIE's expected residual returns if they occur are called variable interests. Variable interests may include, but are not limited to, equity interests, debt instruments, beneficial interests, derivative instruments and guarantees. The Interpretation requires an entity to consolidate a VIE if that entity will absorb a majority of the VIE's expected losses if they occur, receive a majority of the VIE's expected residual returns if they occur, or both. If no party will absorb a majority of the expected losses or expected residual returns, no party will consolidate the VIE. The Interpretation also requires disclosure of significant variable interests in unconsolidated VIE's. The Interpretation is effective for all new variable interest entities created or acquired after January 31, 2003. For variable interest entities created or acquired prior to February 1, 2003, the provisions of the Interpretation were initially to be effective for the first interim or annual period ending after June 15, 2003. However, in October 2003, the FASB delayed the required effective date of the Interpretation on those entities to the first period beginning after December 15, 2003. Additionally, in December 2003, the FASB issued a revision to the Interpretation to clarify certain provisions and to exempt certain entities from its requirements. The revised Interpretation will require full implementation in the first quarter of 2004. We adopted the original Interpretation in 2003 with no material effect to the consolidated financial statements. The effect of the adoption of the revised Interpretation is not expected to be material to the consolidated financial statements.

The FASB issued revised SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits." This Statement addresses disclosure requirements for pensions and other postretirement benefits. The provisions of this Statement retain the disclosure requirements of the previously issued SFAS No. 132 and expand the disclosure requirements to include information describing types of plan assets, investment strategy, measurement date, plan obligations and cash flows. Additionally, the Statement requires disclosure of the components of net periodic benefit cost recognized during interim periods. This Statement is effective for financial statements with fiscal years and interim periods ending after December 15, 2003, except for the disclosure of estimated future benefit payments, which is effective for fiscal years ending after June 15, 2004.

EITF Issue No. 01-8, "Determining Whether An Arrangement Contains a Lease," became effective on July 1, 2003, and provides guidance for determining whether certain contracts such as transportation, storage, load serving, and tolling agreements are executory service arrangements or leases pursuant to SFAS No. 13. A prospective transition is provided for whereby the consensus is to be applied to arrangements consummated or modified after July 1, 2003. Our review indicates that certain of Power's tolling agreements could be considered leases under the consensus if the tolling agreements are modified after July 1, 2003. If such tolling agreements are deemed to be capital leases, the net present value of the demand payments would be reported on the balance sheet consistent with debt as an obligation under capital lease, and as an asset in property, plant and equipment.

The SEC staff, in a letter to the EITF Chairman, raised the issue of classification of leased mineral rights, for companies subject to SFAS No. 19 "Financial Accounting and Reporting by Oil and Gas Producing Companies" that acquire leased mineral rights. Specifically, the SEC staff has stated its view that leased mineral rights meet the definition of an intangible asset under SFAS No. 141 "Business Combinations" and are thus subject to the disclosure requirements of SFAS No. 142 "Goodwill and Other Intangible Assets." At December 31, 2003 and 2002, our Exploration & Production segment had net leased mineral rights of $1.9 billion and $2.1 billion, respectively. The leased mineral rights would continue to be amortized over their remaining useful life, where appropriate. The effect of such a reclassification, if required, is not expected to affect our Statement of Operations or Statement of Cash Flows.

NOTE 2. DISCONTINUED OPERATIONS

During 2002, we began the process of selling certain assets and/or businesses to address liquidity issues. The businesses discussed below represent components that have been sold or approved for sale by our Board of Directors as of December 31, 2003. Therefore, their results of operations (including any impairments, gains or losses), financial position and cash flows have been reflected in the consolidated financial statements and notes as discontinued operations.

During second-quarter 2004, our Board of Directors approved a plan to negotiate and facilitate the sale of our three natural gas liquid extraction plants (straddle plants) in western Canada. We expect to complete the sale in the third quarter of 2004. These assets were previously written down to estimated fair value, resulting in a $36.8 million impairment in fourth-quarter 2002 and an additional $41.7 million impairment in fourth-quarter 2003. In 2004, the fair value of the assets increased substantially due primarily to renegotiation of certain customer contracts and a general improvement in the market for processing assets. These operations were part of the Midstream segment. Consequently, the results of operations of the straddle plants have been reclassified to discontinued operations in the consolidated financial statements and in the tables below. All prior periods reflect this classification.

SUMMARIZED RESULTS OF DISCONTINUED OPERATIONS

Summarized results of discontinued operations for the years ended December 31, 2003, 2002, and 2001 are as follows:

	2003	2002	2001
		(MILLIONS)	
Revenues	$ 2,620.9	$ 6,007.7	$ 7,006.5
Income from discontinued operations before income taxes	$ 167.6	$ 348.0	$ 231.0
(Impairments) and gain (loss) on sales-net	169.0	(567.8)	(184.8)
Losses associated with performance on WilTel guarantee obligations	-	-	(1,839.2)
Benefit (provision) for income taxes	(95.7)	62.2	674.8
Income (loss) from discontinued operations	$ 240.9	$ (157.6)	$ (1,118.2)

SUMMARIZED ASSETS AND LIABILITIES OF DISCONTINUED OPERATIONS

Summarized assets and liabilities of discontinued operations as of December 31, 2003 and 2002, are as follows:

	2003	2002
	(MILLIONS)	
Total current assets	$ 175.4	$ 757.6
Property, plant and equipment -- net	609.0	3,540.0
Other non-current assets	2.0	268.5
Total non-current assets	611.0	3,808.5
Total assets	$ 786.4	$4,566.1
Reflected on balance sheet as:		
Current assets	$ 441.3	$1,297.3
Non-current assets	345.1	3,268.8
Total assets	$ 786.4	$4,566.1
Long-term debt due within one year	$ 1.2	$ 70.6
Other current liabilities	81.5	461.3
Total current liabilities	82.7	531.9
Long-term debt	.3	829.3
Minority interests	--	340.0
Other non-current liabilities	12.7	113.5
Total non-current liabilities	13.0	1,282.8
Total liabilities	$ 95.7	$1,814.7
Reflected on balance sheet as:		
Current liabilities	$ 95.7	$ 550.2

Non-current liabilities	--	1,264.5
Total liabilities	$ 95.7	$1,814.7

HELD FOR SALE AT DECEMBER 31, 2003

Alaska refining, retail and pipeline operations

On November 17, 2003, we entered into agreements to sell our Alaska refinery, retail and pipeline assets for approximately $265 million in cash, subject to various closing adjustments. The transactions are expected to close in the first quarter of 2004 following the completion of various closing conditions.

Throughout the sales negotiation process, we regularly reassessed the estimated fair value of these assets based on information obtained from the sales negotiations using a probability-weighted approach. As a result, impairment charges of $8 million and $18.4 million were recorded during 2003 and 2002, respectively. These impairments are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

Gulf Liquids New River Project LLC

During second-quarter 2003, our Board of Directors approved a plan authorizing management to negotiate and facilitate a sale of the assets of Gulf Liquids New River Project LLC (Gulf Liquids). We recognized impairment charges totaling $108.7 million during 2003 to reduce the carrying cost of the long-lived assets to estimated fair value less costs to sell the assets. These charges are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. We estimated fair value based on a probability-weighted analysis of various scenarios including expected sales prices, salvage valuations and discounted cash-flows. We expect to complete the sale of these operations within one year of the Board's approval. These operations were part of our Midstream segment.

2003 COMPLETED TRANSACTIONS

Canadian liquids operations

During 2003, we completed the sales of certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at our Redwater, Alberta plant for total proceeds of $246 million in cash. We recognized pre-tax gains totaling $92.1 million in 2003 on the sales which are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These operations were part of our Midstream segment.

Soda ash operations

On September 9, 2003, we completed the sale of our soda ash mining facility located in Colorado. The December 31, 2002 carrying value reflected the then estimated fair value less cost to sell. During 2003, ongoing sale negotiations continued to provide new information regarding estimated fair value, and, as a result, we recognized additional impairment charges of $17.4 million in 2003. We also recognized a loss on the sale in 2003 of $4.2 million. These impairments, the loss on the sale and previous impairments of $133.5 million in 2002 and $170 million in 2001 are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. The soda ash operations were part of the previously reported International segment.

Williams Energy Partners

On June 17, 2003, we completed the sale of our 100 percent general partnership interest and 54.6 percent limited partner investment in Williams Energy Partners for $512 million in cash and assumption by the purchasers of $570 million in debt. In December 2003, we received additional cash proceeds of $20 million following the occurrence of a contingent event. We recognized a total pre-tax gain of $310.8 million on the sale during 2003, including the $20 million of additional proceeds, all of which is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. We deferred an additional $113 million associated with our indemnifications of the purchasers for a variety of matters, including obligations that may arise associated with existing environmental contamination relating to operations prior to April 2002 and identified prior to April 2008 (see Note 16).

Bio-energy facilities

On May 30, 2003, we completed the sale of our bio-energy operations for $59 million in cash. During 2003, we recognized an additional pre-tax loss on the sale of $5.4 million. We recorded impairment charges totaling $195.7 million, including $23 million related to goodwill, during 2002, to reduce the carrying cost to our estimate of fair value, less cost to sell, at that time. Both the additional loss and impairment charges are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

Natural gas properties

On May 30, 2003, we completed the sale of natural gas exploration and production properties in the Raton Basin in southern Colorado and the Hugoton Embayment in southwestern Kansas. This sale included all of our interests within these basins. We recognized a $39.7 million gain on the sale during 2003. The gain is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These properties were part of the Exploration & Production segment.

Texas Gas

On May 16, 2003, we completed the sale of Texas Gas Transmission Corporation for $795 million in cash and the assumption by the purchaser of $250 million in existing Texas Gas debt. We recorded a $109 million impairment charge in first-quarter 2003 reflecting the excess of the carrying cost of the long-lived assets over our estimate of fair value based on our assessment of the expected sales price pursuant to the purchase and sale agreement. The impairment charge is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. No significant gain or loss was recognized on the subsequent sale. Texas Gas was a segment within Gas Pipeline.

Midsouth Refinery and related assets

On March 4, 2003, we completed the sale of our refinery and other related operations located in Memphis, Tennessee for $455 million in cash. We had previously written these assets down by $240.8 million to their estimated fair value less cost to sell at December 31, 2002. We recognized a pre-tax gain on sale of $4.7 million in the first quarter of 2003. During the second quarter of 2003, we recognized a $24.7 million pre-tax gain on the sale of an earn-out agreement that we retained in the sale of the refinery. The 2002 impairment charge and subsequent gains are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

Williams travel centers

On February 27, 2003, we completed the sale of our travel centers for approximately $189 million in cash. We had previously written these assets down by $146.6 million in 2002 and $14.7 million in 2001 to their estimated fair value less cost to sell at December 31, 2002. These impairments are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. We did not recognize a significant gain or loss on the sale. These operations were part of the previously reported Petroleum Services segment.

2002 COMPLETED TRANSACTIONS

Central

On November 15, 2002, we completed the sale of our Central natural gas pipeline for $380 million in cash and the assumption by the purchaser of $175 million in debt. Impairment charges totaling $91.3 million during 2002 are reflected in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. Central was a segment within Gas Pipeline.

Mid-America and Seminole Pipelines

On August 1, 2002, we completed the sale of our 98 percent interest in Mid-America Pipeline and 98 percent of our 80 percent ownership interest in Seminole Pipeline for $1.2 billion. The sale generated net cash proceeds of $1.15 billion. The preceding table of summarized results of discontinued operations, (impairments) and gain (loss) on sales includes a pre-tax gain of $301.7 million during 2002 and an $11.4 million reduction of the gain during 2003. These assets were part of the Midstream segment.

Kern River

On March 27, 2002, we completed the sale of our Kern River pipeline for $450 million in cash and the assumption by the purchaser of $510 million in debt. As part of the agreement, $32.5 million of the purchase price was contingent upon Kern River receiving a certificate from the FERC to construct and operate a future expansion. We received the certificate in July 2002, and recognized the contingent payment plus interest as income from discontinued operations in third-quarter 2002. Included as a component of (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations is a pre-tax loss of $6.4 million for the year ended December 31, 2002. Kern River was a segment within Gas Pipeline.

WILTEL

Spinoff and related information

On March 30, 2001, our Board of Directors approved a tax-free spinoff of WilTel to our shareholders. On April 23, 2001, we distributed 398.5 million shares, or approximately 95 percent of our WilTel common stock, to holders of our common stock. Accordingly, the results of operations, financial position and cash flows for WilTel have been reflected in the accompanying consolidated financial statements and notes as discontinued operations.

In an effort to strengthen WilTel's capital structure, prior to the spinoff we took the following steps:

- We contributed an outstanding promissory note from WilTel of approximately $975 million.

- We contributed certain other assets, including the Williams Technology Center (Technology Center) and other ancillary assets under construction. We also committed to complete construction of the Technology Center. Later in 2001, we repurchased the Technology Center and three corporate aircraft from WilTel for $276 million. We then leased these assets back to WilTel.

- We provided indirect credit support for $1.4 billion of the WCG Note Trust Notes.

- We provided a guarantee of WilTel's obligations under a 1998 asset defeasance program (ADP) transaction in which WilTel entered into a lease agreement covering a portion of its fiber-optic network. WilTel had an option to purchase the covered network assets during the lease term at an amount approximating lessor's cost of $750 million.

2001 post spinoff and accounting

Prior to filing our 2001 Annual Report on Form 10-K, WilTel announced that it might seek to reorganize under the U.S. Bankruptcy Code. As a result, we determined that it was probable we would be unable to fully recover certain receivables and our investment in WilTel. We also concluded that it was probable that we would be required to perform under certain guarantees and payment obligations. Using the information available prior to March 7, 2002 and under the circumstances, we developed an estimated range of loss related to our total WilTel exposure. As part of this evaluation, we considered our position as an unsecured creditor, the fair value of the leased assets securing the Technology Center lease, likely recoveries from a successful reorganization process under Chapter 11 of the U.S. Bankruptcy Code, and the enterprise value of WilTel. We also received assistance from external legal counsel and an external financial and restructuring advisor. At that time, we believed that no loss within the range was more probable than another. Accordingly, we recorded the $2.05 billion minimum amount of the range of loss. This is reported in the 2001 Consolidated Statement of Operations as a $1.84 billion pre-tax charge to discontinued operations and a $213 million pre-tax charge to continuing operations.

The $1.84 billion pre-tax charge to discontinued operations includes portions of the following items:

- Indirect credit support for $1.4 billion of WCG Note Trust Notes and related interest.
- Guarantee of the ADP transaction.

The $213 million pre-tax charge to continuing operations includes portions of the following items:

- $106 million of receivables from services prior to the spinoff
- $269 million receivable for the Technology Center lease
- the remaining investment in WilTel common stock, which had previously been written down by $70.9 million earlier in 2001

2002 developments and accounting

In 2002, we acquired all of the WCG Note Trust Notes by exchanging $1.4 billion of our Senior Unsecured 9.25 percent Notes due March 2004. WilTel was indirectly obligated to reimburse us for any payments we were required to make in connection with the WCG Note Trust Notes.

On March 29, 2002, we funded the $754 million purchase price related to WilTel's March 8, 2002 exercise of its option to purchase the covered network assets under the ADP transaction. The payment entitled us to an unsecured note from WilTel for the same amount.

On April 22, 2002, WilTel filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. On October 15, 2002, WilTel consummated its reorganization plan. Under this plan:

- our common stock ownership in WilTel was cancelled,
- we recovered $180 million of claims against WilTel through the sale of those claims to WilTel's new parent organization, and
- we sold the Technology Center back to WilTel in exchange for two promissory notes due in seven and one-half years and four years and secured by a mortgage on the Technology Center.

During 2002, we recognized additional pre-tax charges of $268.7 million in continuing operations related to the recovery and settlement of our receivables and claims against WilTel.

Status at December 31, 2003

At December 31, 2003, we have a $110.8 million receivable from WilTel for the promissory notes relating to the sale of the Technology Center pursuant to the WilTel reorganization plan. The receivable is included in other assets and deferred charges.

We have provided guarantees in the event of nonpayment by WilTel on certain lease performance obligations of WilTel that extend through 2042 and have a maximum potential exposure of approximately $51 million at December 31, 2003. Our exposure declines systematically throughout the remaining term of WilTel's obligations. The carrying value of these guarantees is approximately $46 million at December 31, 2003 and is recorded as a non-current liability.

NOTE 3. INVESTING ACTIVITIES

INVESTING INCOME (LOSS)

Investing income (loss) for the years ended December 31, 2003, 2002 and 2001, is as follows:

	2003	2002	2001
		(MILLIONS)	
Equity earnings (losses)*	$ 20.3	$ 73.0	$ 22.7
Income (loss) from investments*	(25.3)	42.1	4.2
Impairments of cost based investments	(35.0)	(12.1)	(5.6)
Write-down of investment in WilTel stock (see Note 2)	--	--	(95.9)
Loss provision for WilTel receivables (see Note 2)	--	(268.7)	(188.0)
Interest income and other	113.1	52.5	90.0
Total	$ 73.1	$ (113.2)	$ (172.6)

* Items also included in segment profit.

Equity earnings for the year ended December 31, 2002, includes a benefit of $27.4 million for a contractual construction completion fee received by one of our equity affiliates whose operations are accounted for under the equity method of accounting. This equity affiliate served as the general contractor on the Gulfstream pipeline project for Gulfstream Natural Gas System (Gulfstream), an interstate natural gas pipeline subject to FERC regulations and an equity affiliate of ours. The fee paid by Gulfstream was for the early completion during second-quarter 2002 of the construction of Gulfstream's pipeline. It was capitalized by Gulfstream as property, plant and equipment and is included in Gulfstream's rate base to be recovered in future revenues.

Income (loss) from investments for the year ended December 31, 2003, includes:

- a $43.1 million impairment of our investment in equity and debt securities of Longhorn Partners Pipeline L.P., which is included in the Other segment;

- a $14.1 million impairment of our equity interest in Aux Sable, which is included in the Power segment;

- a $13.5 million gain on the sale of stock in eSpeed Inc., which is included in the Power segment; and

- an $11.1 million gain on sale of our equity interest in West Texas LPG Pipeline, L.P. which is included in the Midstream segment.

Income (loss) from investments for the year ended December 31, 2002, includes:

- a $58.5 million gain on sale of our investment in AB Mazeikiu Nafta, a Lithuanian oil refinery, pipeline and terminal complex, which is included in the Other segment;

- a $12.3 million write-off of Gas Pipeline's investment in a pipeline project which was cancelled in 2002;

- a $10.4 million net write-down pursuant to the sale of our equity interest in Alliance Pipeline, a Canadian and U.S. gas pipeline, which is included in the Gas Pipeline segment; and

- an $8.7 million gain on sale of our general partner equity interest in Northern Border Partners, L.P., which is included in the Gas Pipeline segment.

Income (loss) from investments for the year ended December 31, 2001, includes:

- a $27.5 million gain on the sale of our limited partnership interest in Northern Border Partners, L.P., which is included in the Gas Pipeline segment; and

- $23.3 million of write-downs of certain investments which are included in the Power segment.

Impairments of cost based investments for the year ended December 31, 2003, includes:

- a $13.5 million impairment of investment in ReserveCo, a company holding phosphate reserves, and

- a $13.2 million impairment of investment in Algar Telecom S.A.

The 2002 and 2001 impairments of cost based investments relate primarily to various international investments.

Interest income for the year ended December 31, 2003, includes approximately $34 million of interest income at Power as the result of certain recent FERC proceedings.

INVESTMENTS

Investments at December 31, 2003 and 2002, are as follows:

	2003	2002
	(MILLIONS)	
Equity method:		
Gulfstream Natural Gas System, LLC -- 50%	$ 730.8	$ 734.4
Discovery Pipeline -- 50%	194.6	75.3
Longhorn Partners Pipeline, L.P. -- 32.7%	85.1	89.3
ACCROVEN -- 49.3%	67.1	60.4
Alliance Aux Sable -- 14.6%	42.8	54.8
Petrolera Entre Lomas S.A. -- 40.8%	41.5	35.8
Other	71.8	140.1
	1,233.7	1,190.1
Cost method:		
Algar Telecom S.A. -- common and preferred stock	15.3	52.8
Various international funds	48.9	53.9
Indonesian toll road	23.7	23.7
Other	24.8	33.5
	112.7	163.9
Advances to Longhorn Partners Pipeline, L.P.	117.2	100.9
Other	--	13.7
	$ 1,463.6	$ 1,468.6

In December 2003, our Midstream subsidiary made an additional $127 million investment in Discovery Pipeline which was subsequently used by Discovery Pipeline to repay maturing debt. All owners contributed amounts equal to their ownership percentage so our 50 percent ownership in Discovery remained unchanged. Also during 2003, Midstream sold its investments in four pipelines that had a combined book value of approximately $63 million at December 31, 2002.

During February 2004, we were a party to a recapitalization plan completed by Longhorn Partners Pipeline, L.P. (Longhorn). As a result of this plan, we sold a portion of our equity investment in Longhorn for $11.4 million, received $58 million in repayment of a portion of our advances to Longhorn and converted the remaining advances, including accrued interest, into preferred equity interests in Longhorn. These preferred equity interests are subordinate to the preferred interests held by the new investors. No gain or loss was recognized on this transaction.

Dividends and distributions received from companies carried on the equity basis were $21 million, $81 million and $51 million in 2003, 2002 and 2001, respectively. The $27.4 million Gulfstream construction completion fee described previously is included in the 2002 distributions.

GUARANTEES ON BEHALF OF INVESTEES

We have guaranteed commercial letters of credit totaling $17 million on behalf of ACCROVEN. These expire in January 2005, have no carrying value and are fully collateralized with cash.

In connection with the construction of a joint venture pipeline project, we guaranteed, through a put agreement, certain portions of the joint venture's project financing in the event of nonpayment by the joint venture. Our potential liability under this guarantee ranges from zero percent to 100 percent of the outstanding project financing, depending on our ability and the other project members' ability to meet certain performance criteria. As of December 31, 2003, the total outstanding project financing is $31.7 million. Our maximum potential liability is the full amount of the financing, but based on the current status of the project, it is likely that any obligation would be limited to 50 percent of the outstanding financing. As additional borrowings are made under the project financing facility, our potential exposure will increase. This guarantee expires in March 2005, and we have not accrued any amounts at December 31, 2003.

We have provided guarantees on behalf of certain partnerships in which we have an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. These guarantees continue until we withdraw from the partnerships. No amounts have been accrued at December 31, 2003.

NOTE 4. ASSET SALES, IMPAIRMENTS AND OTHER ACCRUALS

Significant gains or losses from asset sales, impairments and other accruals included in other (income) expense - net within segment costs and expenses for the years ended December 31, 2003, 2002 and 2001, are as follows:

	(INCOME) EXPENSE		
	2003	2002	2001
		(MILLIONS)	
POWER			
Gain on sale of full requirements contract	$ (188.0)	$ --	$ --
Commodity Futures Trading Commission settlement	20.0	--	--
California rate refund and other accrual adjustments	19.5	--	--
Impairment of goodwill	45.0	61.1	--
Impairment of generation facilities	44.1	44.7	--
Loss accruals and impairment of other power related assets	--	82.6	--
Guarantee loss accruals and write-offs	--	56.2	--
Impairment of plant for terminated expansion	--	--	13.3
GAS PIPELINE			
Write-off of software development costs due to cancelled implementation	25.6	--	--
Loss accrual for litigation and claims	--	--	18.3
EXPLORATION & PRODUCTION			
Net gain on sales of certain natural gas properties	(96.7)	(141.7)	--
MIDSTREAM GAS & LIQUIDS			
Gain on sale of the wholesale propane business	(16.2)	--	--
Impairment of Canadian olefin assets	--	78.2	--
Impairment of south Texas assets	--	--	13.8
OTHER			
Gain on sale of certain convenience stores	--	--	(75.3)
Impairment of end-to-end mobile computing systems business	--	--	12.1

POWER

In June 2002, we announced our intent to exit the Power business. As a result, Power pursued efforts to sell all or portions of our power, natural gas, and crude and refined products portfolios in the latter half of 2002 and in 2003. Based on bids received in these sales efforts, we impaired certain assets and projects in 2002. During 2003, we continued our focus on exiting the Power business and, as a result, impaired certain assets.

California Rate Refund and Other Accrual Adjustments. In addition to the $19.5 million charge included in other (income) expense -- net within segment costs and expenses for 2003, a $13.8 million charge is recorded within costs and operating expenses. These two amounts, totaling $33.3 million, are for California rate refund liability and other accrual adjustments and relate to power marketing activities in California during 2000 and 2001. See Note 16 for further discussion.

Goodwill. The fair value of the Power reporting unit used to calculate the goodwill impairment loss in 2002 was based on the estimated fair value of the trading portfolio inclusive of the fair value of contracts with affiliates. In 2002, the trading portfolio was reflected at fair value in the financial statements and the affiliate contracts were not. The fair value of the affiliate contracts was estimated using a discounted cash flow model with natural gas pricing assumptions based on current market information.

During 2003, we continued to focus on exiting the Power business. Because of this and current market conditions in which this business operates, we evaluated Power's remaining goodwill for impairment. In estimating the fair value of the Power reporting unit, we considered our derivative portfolio which is carried at fair value on the balance sheet and our non-derivative portfolio which is no longer carried at fair value on the balance sheet. Because of the significant negative fair value of certain of our non-derivative contracts, we may be unable to realize our carrying value of this reporting unit. As a result, we recognized a $45 million impairment of the remaining goodwill within Power during 2003.

Generation Facilities. The 2003 impairment relates to the Hazelton generation facility. Fair value was estimated using future cash flows based on current market information and discounted at a risk adjusted rate. The 2002 impairment was related to the Worthington generation facility. Fair value was estimated based on expected proceeds from the sale of the facility, which closed in first-quarter 2003.

Loss Accruals and Impairment of Other Power Related Assets. The 2002 loss accruals and impairments of other power related assets were recorded pursuant to reducing activities associated with the distributive power generation business.

Guarantee Loss Accruals and Write-Offs. The 2002 guarantee loss accruals and write-offs within Power of $56.2 million includes accruals for commitments for certain assets that were previously planned to be used in power projects, write-offs associated with a terminated power plant project and a $13.2 million reversal of loss accruals related to the wind-down of our mezzanine lending business.

MIDSTREAM GAS & LIQUIDS

Canadian Olefin Assets. The 2002 impairment is associated with an olefin fractionation facility and reflects a reduction of carrying cost to management's estimate of fair market value, determined primarily from information available from efforts to sell these assets.

NOTE 5. PROVISION (BENEFIT) FOR INCOME TAXES

The provision (benefit) for income taxes from continuing operations includes:

	2003	2002	2001
		(MILLIONS)	
Current:			
Federal	$ (8.8)	$ (126.7)	$ 167.9
State	(17.6)	27.5	9.7
Foreign	8.8	21.4	7.7
	(17.6)	(77.8)	185.3
Deferred:			
Federal	29.1	(150.6)	265.6
State	51.3	(56.6)	37.0
Foreign	(15.1)	7.8	19.7
	65.3	(199.4)	322.3
Total provision (benefit)	$ 47.7	$ (277.2)	$ 507.6

Reconciliations from the provision (benefit) for income taxes from continuing operations at the federal statutory rate to the provision (benefit) for income taxes are as follows:

	2003	2002	2001
		(MILLIONS)	
Provision (benefit) at statutory rate	$ 26.6	$ (306.0)	$ 401.8
Increases (reductions) in taxes resulting from:			
State income taxes (net of federal benefit)	5.0	(19.0)	30.4
Foreign operations - net	3.5	81.6	12.6
Capital losses	(39.6)	(121.2)	44.5
Non-deductible impairment of goodwill	15.8	21.7	--
Income tax (credits) recapture	--	26.8	--
Other - net	36.4	38.9	18.3
Provision (benefit) for income taxes	$ 47.7	$ (277.2)	$ 507.6

Significant components of deferred tax liabilities and assets as of December 31, 2003 and 2002, are as follows:

	2003	2002
	(MILLIONS)	
Deferred tax liabilities:		
Property, plant and equipment	$ 2,118.8	$ 2,183.1
Derivatives - net	149.9	642.7
Investments	514.8	568.0
Other	195.8	168.9
Total deferred tax liabilities	2,979.3	3,562.7
Deferred tax assets:		
Minimum tax credits	151.5	151.7
Accrued liabilities	208.7	314.5
Receivables	52.5	68.2
Federal carryovers	115.7	216.2
Foreign carryovers	46.2	72.9
Other	125.7	111.3
Total deferred tax assets	700.3	934.8
Valuation allowance	67.8	156.5
Net deferred tax assets	632.5	778.3
Overall net deferred tax liabilities	$ 2,346.8	$ 2,784.4

Valuation allowances at December 31, 2003 serve to reduce the recognized tax benefit associated with foreign asset impairments and foreign carryovers to an amount that will, more likely than not, be realized. Valuation allowances at December 31, 2002 serve to reduce the recognized tax benefit associated with federal capital loss carryovers, foreign asset impairments and foreign carryovers to an amount that will, more likely than not, be realized. The valuation allowance decreased $89 million and $23 million in 2003 and 2002, respectively.

Utilization of foreign operating loss carryovers reduced the provision for income taxes during 2003 by $19 million.

Undistributed earnings of certain consolidated foreign subsidiaries at December 31, 2003, amounted to approximately $45 million. No provision for deferred U.S. income taxes has been made for these subsidiaries because we intend to permanently reinvest such earnings in those foreign operations.

The impact of foreign operations on the effective tax rate increased during 2002 due to the recognition of U.S. tax on foreign dividend distributions and recording of a financial impairment on certain foreign assets for which a valuation allowance was established.

Federal net operating loss carryovers, charitable contribution carryovers, and capital loss carryovers of $204 million, $58 million and $68 million, respectively, at the end of 2003 are expected to be utilized prior to expiration in 2007 through 2022.

Cash refunds for income taxes (net of payments) were $88 million in 2003. Cash payments for income taxes (net of refunds) were $36 million and $87 million in 2002 and 2001, respectively.

During the course of audits of our business by domestic and foreign tax authorities, we frequently face challenges regarding the amount of taxes due. These challenges include questions regarding the timing and amount of deductions and the allocation of income among various tax jurisdictions. In evaluating the liability associated with our various filing positions, we record a liability for probable tax contingencies. In association with this liability, we record an estimate of related interest as a component of our current tax provision. The impact of this accrual is included within Other - net in our reconciliation of the tax provision to the federal statutory rate.

NOTE 6. EARNINGS (LOSS) PER SHARE

Basic and diluted earnings (loss) per common share for the years ended December 31, 2003, 2002 and 2001, are as follows:

	2003	2002	2001
	(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS; SHARES IN THOUSANDS)		
Income (loss) from continuing operations	$ 28.2	$ (597.1)	$ 640.5
Convertible preferred stock dividends (see Note 13)	29.5	90.1	-
Income (loss) from continuing operations available to common stockholders for basic and diluted earnings per share	$ (1.3)	$ (687.2)	$ 640.5
Basic weighted-average shares	518,137	516,793	496,935
Effect of dilutive securities:			
Stock options	-	-	3,632
Diluted weighted-average shares	518,137	516,793	500,567
Earnings (loss) per share from continuing operations:			
Basic	$ -	$ (1.33)	$ 1.29
Diluted	$ -	$ (1.33)	$ 1.28

For the year ended December 31, 2003, approximately 3.6 million weighted-average stock options, approximately 6.4 million weighted average shares related to the assumed conversion of 9.875 percent cumulative convertible preferred stock, approximately 2.5 million weighted-average unvested deferred shares and approximately 16.5 million weighted-average shares related to the assumed conversion of convertible debentures, as well as the related interest, that otherwise would have been included, have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive. The preferred stock was redeemed in June 2003.

For the year ended December 31, 2002, approximately 666 thousand weighted-average stock options, approximately 11.3 million weighted-average shares related to the assumed conversion of the 9.875 percent cumulative convertible preferred stock and approximately 3.6 million weighted-average unvested deferred shares, that otherwise would have been included, have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive.

Additionally, approximately 15.0 million, 38.7 million and 15.3 million options to purchase shares of common stock with weighted-average exercise prices of $22.77, $19.90 and $36.12, respectively, were outstanding on December 31, 2003, 2002 and 2001, respectively, but have been excluded from the computation of diluted earnings per share. Inclusion of these shares would have been antidilutive, as the exercise prices of the options exceeded the average market prices of the common shares for the respective years.

NOTE 7. EMPLOYEE BENEFIT PLANS

The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits for the years indicated. It also presents a reconciliation of the funded status of these benefits to the amount recorded in the Consolidated Balance Sheet at December 31 of each year indicated. The annual measurement date for our plans is December 31. Prior year amounts have been restated to exclude those benefit plans where we will no longer serve as sponsor related to those operations reported as discontinued operations (see Note 1). Changes in the obligations or assets of continuing plans associated with the transfer of such obligations or assets in a sale or planned sale reflected as discontinued operations have been reflected as divestitures in the following tables.

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2003	2002	2003	2002
	(MILLIONS)			
Change in benefit obligation:				
Benefit obligations at beginning of year	$ 788.9	$ 870.2	$ 410.5	$ 489.0
Service cost	25.5	32.5	6.2	7.1
Interest cost	52.7	59.3	24.1	31.8
Plan participants' contributions	--	--	3.3	3.9
Curtailment	--	(.8)	--	--
Settlement benefits paid	(6.1)	(18.7)	--	--
Benefits paid	(87.1)	(116.0)	(24.6)	(26.3)
Divestiture	(.8)	(3.3)	(118.3)	(27.0)
Special termination benefit cost	--	29.5	--	1.5
Actuarial (gain) loss	2.8	(63.8)	61.2	(69.5)
Benefit obligation at end of year	775.9	788.9	362.4	410.5
Change in plan assets:				
Fair value of plan assets at beginning of year	592.9	725.0	193.9	247.6
Actual return on plan assets	155.8	(94.7)	36.1	(34.9)
Divestiture	--	--	(70.2)	(20.2)
Employer contributions	50.8	97.3	14.2	23.8
Plan participants' contributions	--	--	3.3	3.9
Benefits paid	(87.1)	(116.0)	(24.6)	(26.3)
Settlement benefits paid	(6.1)	(18.7)	--	--
Fair value of plan assets at end of year	706.3	592.9	152.7	193.9
Funded status	(69.6)	(196.0)	(209.7)	(216.6)
Unrecognized net actuarial loss	195.5	309.5	44.5	14.3
Unrecognized prior service cost (credit)	(4.6)	(7.2)	1.5	(1.5)
Unrecognized transition obligation	--	--	23.6	28.2
Prepaid (accrued) benefit cost	$ 121.3	$ 106.3	$ (140.1)	$ (175.6)
Amounts recognized in the Consolidated Balance Sheet consist of:				
Prepaid benefit cost	$ 164.4	$ 169.1	$ --	$ --
Accrued benefit cost	(53.7)	(91.6)	(140.1)	(175.6)
Accumulated other comprehensive income (before tax)	10.6	28.8	--	--
Prepaid (accrued) benefit cost	$ 121.3	$ 106.3	$ (140.1)	$ (175.6)

The accumulated benefit obligation for pension benefit plans was $720.2 million and $680.5 million at December 31, 2003 and 2002, respectively.

Information for pension plans with projected benefit obligation and accumulated benefit obligation in excess of plan assets as of December 31, 2003 and 2002 is as follows:

	DECEMBER 31,	
	2003	2002
Projected benefit obligation	$ 335.0	$ 368.8
Accumulated benefit obligation	279.2	260.3
Fair value of plan assets	225.5	169.9

Net pension and other postretirement benefit expense for the years ended December 31, 2003, 2002 and 2001, consists of the following:

	PENSION BENEFITS		
	2003	2002	2001
		(MILLIONS)	
Components of net periodic pension expense:			
Service cost	$ 25.5	$ 32.5	$ 30.8
Interest cost	52.7	59.3	60.9
Expected return on plan assets	(54.2)	(65.3)	(80.0)
Amortization of transition asset	--	--	(1.0)
Amortization of prior service credit	(2.5)	(1.6)	(1.4)
Recognized net actuarial loss	13.7	4.0	.8
Regulatory asset amortization (deferral)	3.9	(1.2)	1.2
Settlement/curtailment expense	.6	4.8	--
Special termination benefit cost	--	29.5	--
Net periodic pension expense	$ 39.7	$ 62.0	$ 11.3

	OTHER POSTRETIREMENT BENEFITS		
	2003	2002	2001
		(MILLIONS)	
Components of net periodic postretirement benefit expense (credit):			
Service cost	$ 6.2	$ 7.1	$ 6.9
Interest cost	24.1	31.8	29.5
Expected return on plan assets	(13.0)	(18.9)	(22.6)
Amortization of transition obligation	2.7	4.1	4.1
Amortization of prior service cost	.6	.2	.1
Recognized net actuarial gain	--	--	(2.6)
Regulatory asset amortization	8.6	3.7	14.7
Settlement/curtailment expense (credit)	(41.9)	13.5	--
Special termination benefit cost	--	1.5	--
Net periodic postretirement benefit expense (credit)	$ (12.7)	$ 43.0	$ 30.1

The $(41.9) million and $13.5 million settlement/curtailment expense (credit) included in net periodic postretirement benefit expense in 2003 and 2002, respectively, is included in income (loss) from discontinued operations in the Consolidated Statement of Operations due to the settlement/curtailment directly resulting from the sale of the operations included within discontinued operations.

The weighted-average assumptions utilized to determine benefit obligations as of December 31, 2003 and 2002 are as follows:

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2003	2002	2003	2002
Discount rate	6.25%	7%	6.25%	7%
Rate of compensation increase	5	5	N/A	N/A

The weighted-average assumptions utilized to determine net pension and other postretirement benefit expense for the years ended December 31, 2003, 2002 and 2001, are as follows:

	PENSION BENEFITS			OTHER POSTRETIREMENT BENEFITS		
	2003	2002	2001	2003	2002	2001

Discount rate....................................	7%	7.5%	7.5%	7%	7%	7.5%
Expected return on plan assets..................	8.5	8.5	10	8.5	8.5	10
Expected return on plan assets (net of effective tax rate).......................................	N/A	N/A	N/A	7	7	8.2
Rate of compensation increase...................	5	5	5	N/A	N/A	N/A

The expected rate of return was determined by our Investment Committee by combining a review of the historical returns realized within the portfolio, the investment strategy included in the Plans' Investment Policy Statements, and the capital market projections provided by our independent investment consultants for the asset classifications in which the portfolio is invested and the target weightings of each asset classification.

The annual assumed rate of increase in the health care cost trend rate for 2004 is 11.8 percent, and systematically decreases to 5 percent by 2015.

The nonpension postretirement benefit plans which we sponsor provide for retiree contributions and contain other cost-sharing features such as deductibles and coinsurance. The accounting for these plans anticipates future cost-sharing that is consistent with our expressed intent to increase the retiree contribution rate generally in line with health care cost increases.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act introduces a prescription drug benefit under Medicare (Medicare Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Our health care plan for retirees includes prescription drug coverage. Management is evaluating the impact of the Act on the future obligations of the plan. In accordance with FASB Staff Position No. FAS 106-1, the provisions of the Act are not reflected in any measures of benefit obligations or other postretirement benefit expense in the financial statements or accompanying notes. Authoritative guidance on the accounting for a federal subsidy is pending and that guidance, when issued, could require us to change previously reported information.

The health care cost trend rate assumption has a significant effect on the amounts reported. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	POINT INCREASE	POINT DECREASE
	(MILLIONS)	
Effect on total of service and interest cost components...	$ 5.1	$ (4.1)
Effect on postretirement benefit obligation..............	50.9	(46.2)

The amount of postretirement benefit costs deferred as a net regulatory asset at December 31, 2003 and 2002, is $24 million and $57.5 million, respectively, and is expected to be recovered through rates over approximately 8 years.

Our pension plans' weighted-average asset allocations at December 31, 2003 and 2002, by asset category are as follows:

	PLAN ASSETS AT DECEMBER 31, 2003	2002
Equity securities......................................	82%	78%
Debt securities..	13	16
Other..	5	6
	100%	100%

Included in equity securities are investments in commingled funds that invest entirely in equity securities and comprise 38 percent of the pension plans' weighted-average assets at December 31, 2003 and 2002. Other assets are comprised primarily of cash and cash equivalents.

Our investment strategy for the assets within the pension plans is to maximize investment returns with prudent levels of risk to meet current and projected financial requirements of the pension plans. These risks are evaluated, in part, from an asset-only standpoint as to investment allocation, investment style and manager selection. Additional risk perspectives are reviewed considering the allocation of assets and the structure of the plan liabilities and the combined effects on the plans. Our investment policy for the pension plan assets includes a target asset allocation. The target for equity securities is 84 percent and debt securities and other is 16 percent at December 31, 2003.

Our other postretirement benefits plan weighted-average asset allocations at December 31, 2003 and 2002, by asset category are as follows:

	PLAN ASSETS AT DECEMBER 31, 2003	2002
Equity securities	74%	69%
Debt securities	14	19
Other	12	12
	100%	100%

Included in equity securities are investments in commingled funds that invest entirely in equity securities and comprise 22 percent and 17 percent of the other postretirement benefit plans' weighted-average assets at December 31, 2003 and 2002, respectively. Other assets are comprised primarily of cash and cash equivalents, and insurance contracts assets.

Our investment strategy for the assets within the other postretirement benefit plans is to maximize investment returns with prudent levels of risk in a tax efficient manner to meet current and projected financial requirements of the other postretirement benefit plans. These risks are evaluated, in part, from an asset-only standpoint as to investment allocation, investment style and manager selection. Additional risk perspectives are reviewed considering the allocation of assets and the structure of the plan liabilities and the combined effects on the plans. Our investment policy for the other postretirement benefit plan assets includes a target asset allocation. The target for equity securities is 80 percent and debt securities and other is 20 percent at December 31, 2003.

We expect to contribute approximately $60 million to our pension plans and approximately $15 million to our other postretirement benefit plans in 2004.

We maintain defined-contribution plans. Costs related to continuing operations of $18 million, $39 million and $24 million were recognized for these plans in 2003, 2002 and 2001, respectively. In 2002, these costs included the cost related to additional contributions to an employee stock ownership plan resulting from the retirement of related external debt.

NOTE 8. INVENTORIES

Inventories at December 31, 2003 and 2002, are as follows:

	2003	2002
	(MILLIONS)	
Raw materials:		
Crude oil	$ 2.1	$ 3.8
Finished goods:		
Refined products	8.0	47.7
Natural gas liquids	40.4	102.8
	48.4	150.5
Materials and supplies	59.9	86.0
Natural gas in underground storage	132.5	125.4
	$ 242.9	$ 365.7

Effective January 1, 2003, we adopted EITF 02-3 (see Note 1). As a result, we reduced the recorded value of natural gas in underground storage by $37.0 million, refined products by $2.9 million and natural gas liquids by $1.0 million. Prior to the adoption of EITF 02-3, we reported inventories related to energy risk management and trading activities at fair value. Subsequent to the adoption, these inventories are reported using the average-cost method.

As of December 31, 2003 less than one percent of inventories were stated at fair value compared with 52 percent at December 31, 2002. Inventories, primarily related to energy risk management and trading activities, stated at fair value at December 31, 2002, included refined products of $23.1 million, natural gas in underground storage of $76.2 million, and natural gas liquids of $90.7 million. Inventories determined using the LIFO cost method were approximately ten percent and seven percent of inventories at December 31, 2003 and 2002, respectively. The remaining inventories were primarily determined using the average-cost method.

Lower-of-cost or market reductions of approximately $1.1 million and $18.2 million were recognized in 2003 and 2002, respectively, related to certain power-related inventories primarily included in materials and supplies.

NOTE 9. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31, 2003 and 2002, is as follows:

	2003	2002
	(MILLIONS)	
Cost:		
Power	$ 190.7	$ 420.9
Gas Pipeline	7,949.1	7,527.5
Exploration & Production	3,235.7	3,174.1
Midstream Gas & Liquids	4,126.7	3,920.2
Other	250.2	319.2
	15,752.4	15,361.9
Accumulated depreciation, depletion and amortization	(4,018.4)	(3,663.7)
	$11,734.0	$11,698.2

Depreciation, depletion and amortization expense for property, plant and equipment was $655.6 million in 2003, $644.8 million in 2002 and $510.0 million in 2001.

Gross property, plant and equipment includes approximately $676 million at December 31, 2003 and $984 million at December 31, 2002 of construction in progress which is not yet subject to depreciation. In addition, property of Exploration & Production includes approximately $675 million at December 31, 2003 and $774 million at December 31, 2002 of capitalized costs from the Barrett acquisition related to properties with probable reserves not yet subject to depletion.

Commitments for construction and acquisition of property, plant and equipment are approximately $60 million at December 31, 2003.

Net property, plant and equipment includes approximately $1.2 billion at December 31, 2003 and 2002, related to amounts in excess of the original cost of the regulated facilities within Gas Pipeline as a result of our prior acquisitions. This amount is being amortized over the estimated remaining useful lives of these assets at the date of acquisition. Current FERC policy does not permit recovery through rates for amounts in excess of original cost of construction.

We adopted SFAS No. 143, "Accounting for Asset Retirement Obligations" on January 1, 2003 (see Note 1). As a result, we recorded a liability of $33.4 million representing the present value of expected future asset retirement obligations at January 1, 2003. The asset retirement obligation at December 31, 2003 is $38.7 million (see Note 1).

NOTE 10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Under our cash-management system, certain subsidiaries' cash accounts reflect credit balances to the extent checks written have not been presented for payment. Accounts payable includes approximately $27 million of these credit balances at December 31, 2003 and $57 million at December 31, 2002.

Accrued liabilities at December 31, 2003 and 2002, are as follows:

	2003	2002
	(MILLIONS)	
Interest	$ 261.2	$ 301.2
Employee costs	153.6	178.8
Taxes other than income taxes	101.2	99.7
Net lease obligation	65.3	58.5
Guarantees and payment obligations related to WilTel	46.1	47.7
Deposits received from customers relating to energy risk management and trading and hedging activities	25.8	141.2
Income taxes	6.2	63.3
Accrued liabilities related to the RMT note payable	--	237.0
Other	285.0	277.1
	$ 944.4	$1,404.5

NOTE 11. DEBT, LEASES AND BANKING ARRANGEMENTS

NOTES PAYABLE AND LONG-TERM DEBT

Notes payable and long-term debt at December 31, 2003 and 2002, are as follows:

	WEIGHTED-AVERAGE INTEREST RATE(1)	DECEMBER 31, 2003	DECEMBER 31, 2002
		(MILLIONS)	
Secured notes payable	6.57%	$ 3.3	$ 996.3
Long-term debt:			
Secured long-term debt			
Revolving credit loans		$ --	$ 81.0
Debentures		--	28.7
Notes, 6.62%-9.45%, payable through 2016	8.0%	243.7	256.8
Notes, adjustable rate, payable through 2016	4.4%	602.5	2.3
Other, payable 2003	--	--	20.9
Unsecured long-term debt			
Debentures, 5.5%-10.25%, payable through 2033	7.0%	1,645.2	1,449.0
Notes, 6.125%-9.25%, payable through 2032(2)	7.7%	9,404.3	9,349.9
Notes, adjustable rate	--	--	669.9
Other, payable through 2005	4.3%	79.3	158.1
Capital leases	--	--	139.9
Total long-term debt, including current		11,975.0	12,156.5
Current portion of long-term debt		(935.2)	(1,080.8)
Total long-term debt		$ 11,039.8	$ 11,075.7

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(1) At December 31, 2003

(2) Includes $1.1 billion of 6.5% notes payable 2007, subject to remarketing in 2004, discussed below.

Notes payable at December 31, 2002, included a $921.8 million secured note (the RMT note payable), which was repaid in May 2003 with proceeds from asset sales and from a new $500 million long-term debt obligation (described below under "Issuances and Retirements").

Long-term debt includes $1.1 billion of 6.5 percent notes, payable in 2007, that are subject to remarketing in 2004. These FELINE PACS include equity forward contracts which require the holder to purchase shares of our common stock in 2005. If the 2004 remarketing is unsuccessful and a second remarketing in February 2005 is unsuccessful, we could exercise our right to foreclose on the notes in order to satisfy the obligation of the holders of the equity forward contracts requiring the holder to purchase our common stock (see Note 13). This would be a non-cash transaction.

In September 2003, our Board of Directors authorized us to retire or otherwise prepay up to $1.8 billion of debt, including $1.4 billion designated for our senior, unsecured 9.25 percent notes due March 15, 2004. On October 8, 2003, we announced a cash tender offer for any and all of our $1.4 billion senior, unsecured 9.25 percent notes as well as cash tender offers and consent solicitations for approximately $241 million of other outstanding notes and debentures. As of the November 6, 2003, tender offer expiration date, we had accepted $721 million of the senior, unsecured 9.25 percent notes for purchase. Additionally, we received tenders of notes and deliveries of related consents from holders of $230 million of the other notes and debentures. In conjunction with the tendered notes and related consents, we paid premiums of approximately $58 million. The premiums, as well as related fees and expenses, together totaling $66.8 million, were recorded in fourth-quarter 2003 as a pre-tax charge to earnings.

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, 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.

Revolving credit and letter of credit facilities

On June 6, 2003, we entered into a two-year $800 million revolving and letter of credit facility, primarily for the purpose of issuing letters of credit. Northwest Pipeline and Transco also have access to all unborrowed amounts under the facility. The facility must be secured by cash and/or acceptable government securities with a market value of at least 105 percent of the then outstanding aggregate amount available for drawing under all letters of credit, plus the aggregate amount of all loans then outstanding. The restricted cash and investments used as collateral are classified on our balance sheet as current or non-current based on the expected ultimate termination date of the underlying debt or letters of credit. The new credit facility replaced a $1.1 billion credit line entered into in July 2002 that was comprised of a $700 million revolving credit facility and a $400 million letter of credit facility secured by substantially all of our Midstream assets. The lenders released these assets as collateral upon termination of the old credit facilities, and they were not pledged in support of the new facility. The interest rate on the new facility is variable at the London InterBank Offered Rate (LIBOR) plus .75 percent, or 1.87 percent at December 31, 2003. As of December 31, 2003, letters of credit totaling $353 million have been issued by the participating financial institutions under this facility and remain outstanding. No revolving credit loans were outstanding. At December 31, 2003, the amount of restricted investments securing this facility was $381 million, which collateralized the facility at approximately 108 percent.

Issuances and retirements

On May 28, 2003, we issued $300 million of 5.5 percent junior subordinated convertible debentures due 2033. These notes, which are callable after seven years, are convertible at the option of the holder into our common stock at a conversion price of approximately $10.89 per share. The proceeds were used to redeem all of the outstanding 9.875 percent cumulative-convertible preferred shares (see Note 13).

On May 30, 2003, our Exploration & Production subsidiary entered into a $500 million secured note due May 30, 2007, at a floating interest rate of LIBOR plus 3.75 percent (totaling 4.92 percent at December 31, 2003). This loan refinances a portion of the RMT note discussed above. Certain of our Exploration & Production interests in the U.S. Rocky Mountains had secured the RMT note payable and now serve as security on the current loan. Significant covenants on the borrower, RMT and its parent Williams Production Holdings LLC (Holdings), include:

- interest coverage ratio computed on a consolidated RMT basis of greater than 3 to 1;
- ratio of the present value of future cash flows of proved reserves, discounted at ten percent, based on the most recent engineering report to total senior secured debt, computed on a consolidated RMT basis, of greater than 1.75 to 1;
- limitation on restricted payments; and
- limitation on intercompany indebtedness.

On February 25, 2004, this loan facility was amended. The maturity date was extended to May 30, 2008, and the interest rate was lowered to LIBOR plus 2.5 percent.

On June 10, 2003, we issued $800 million of 8.625 percent senior unsecured notes due 2010. The notes were issued under our $3 billion shelf registration statement. Significant covenants include:

- limitation on certain payments, including a limitation on the payment of quarterly dividends to no greater than $.02 per common share;
- limitation on asset sales, unless the consideration is at least equal to fair market value and at least 75 percent of the consideration received is in the form of cash or cash equivalents;
- limitation on the use of proceeds from permitted asset sales;
- limitation on transactions with affiliates; and
- limitation on additional indebtedness and issuance of preferred stock unless the Fixed Charge Coverage Ratio for our most recently ended four full fiscal quarters is at least 2 to 1, determined on a proforma basis.

While we do not expect to exceed the fixed charge covenant ratio until the end of 2005, the covenant includes a provision that allows us to refinance our existing revolver and letter of credit facility. These restrictions may be lifted if certain conditions, including our attaining an investment grade rating from both Moody's Investors Service and Standard and Poor's are met.

A summary of significant issuances and retirements of long-term debt, including capital leases, as well as the items listed above, for the year ended December 31, 2003, is as follows:

ISSUE/TERMS	DUE DATE	PRINCIPAL AMOUNT
		(MILLIONS)
Issuances of long-term debt in 2003:		
8.125% senior notes (Northwest Pipeline)	2010	$ 175.0
RMT term B loan (Exploration & Production)	2007	500.0
5.5% junior subordinated convertible debentures	2033	300.0
8.625% senior unsecured notes	2010	800.0
1.97% Midstream Venezuela Project Financing -- SACE	2016	105.0
6.62% Midstream Venezuela Project Financing -- OPIC	2016	125.0
Retirements/prepayments of long-term debt in 2003:		
Preferred interests	2003-2006	$ 302.5
Various capital leases	2005	139.8
Various notes, 6.125%-9.45%	2003-2004	247.4
Various notes, adjustable rate	2003-2004	531.2
Various debentures	2003	7.5
Debt tender offers/consent solicitations accepted for purchase	2003-2022	951.4

Terms of certain of our subsidiaries' borrowing arrangements with lenders limit the transfer of funds to the corporate parent. At December 31, 2003, approximately $105 million of net assets of consolidated subsidiaries was restricted. Of this amount, $91 million is reported as restricted cash on our Consolidated Balance Sheet. In addition, certain equity method investees' borrowing arrangements and foreign government regulations limit the amount of dividends or distributions to the corporate parent. Restricted net assets of equity method investees was approximately $86 million at December 31, 2003.

Aggregate minimum maturities of long-term debt for each of the next five years are as follows:

	(MILLIONS)
2004	$ 932.3
2005	246.8
2006	971.7
2007	2,019.6
2008	384.9

As noted above, the FELINE PACS are subject to remarketing in 2004. If the 2004 remarketing is unsuccessful, a second remarketing will occur in February of 2005. If this attempt at remarketing is unsuccessful, we could exercise our right to foreclose on the notes in order to satisfy the obligation of the holders of the equity forward contracts requiring the holder to purchase our common stock (see Note 13). This would be a non-cash transaction. Otherwise, the notes are not subject to early retirement.

Cash payments for interest (net of amounts capitalized) and other fees recorded as interest expense were as follows: 2003 -- $1.3 billion; 2002 -- $856 million; and 2001 -- $548 million.

LEASES-LESSEE

Future minimum annual rentals under noncancelable operating leases as of December 31, 2003, are payable as follows:

	(MILLIONS)
2004	$ 41.8
2005	36.3
2006	25.8
2007	20.1
2008	19.4
Thereafter	54.9
Total	$198.3

Total rent expense was $110 million in 2003, $93 million in 2002, and $89 million in 2001. In 2003, sublease income from third parties was $16.5 million.

In July 2002, we amended the terms of an operating lease with a special-purpose entity owned by third parties through which we leased offshore oil and gas pipelines and an onshore gas processing plant. The amended terms caused the lease to be reclassified as a capital lease. The capital lease obligation, which was $139.9 million at December 31, 2002, was paid off in second-quarter 2003.

NOTE 12. PREFERRED INTERESTS IN CONSOLIDATED SUBSIDIARIES

Prior to 2003, we transferred certain of our assets into newly created consolidated entities and then sold a non-controlling preferred interest in those entities to outside investors. The outside investors in three of the entities were unconsolidated special purpose entities formed solely for the purpose of purchasing the preferred ownership interest in the respective entity. The special purpose entities were capitalized with no less than three-percent equity from an independent third party. The outside investor in the fourth entity was not a special purpose entity. In each case, the outside investor was entitled to priority distributions from the consolidated entity. The assets and liabilities of these entities are included in the Consolidated Balance Sheet, with the obligations to the outside investors reflected as debt. In 2002 and 2003, we paid the remaining obligations to the outside investors in these entities, as further described below.

SNOW GOOSE ASSOCIATES, L.L.C.

In December 2000, we formed two separate legal entities, Snow Goose Associates, L.L.C. (Snow Goose) and Arctic Fox Assets, L.L.C. (Arctic Fox) for the purpose of generating funds to invest in certain Canadian energy-related assets. An outside investor contributed $560 million in exchange for the non-controlling preferred interest in Snow Goose. The investor in Snow Goose was entitled to quarterly priority distributions, representing an adjustable rate structure. The initial priority return period was scheduled to expire in December 2005.

During first-quarter 2002, the terms of the priority return were amended. Significant terms of the amendment included elimination of covenants regarding our credit ratings, modifications of certain Canadian interest coverage covenants and a requirement to amortize the outside investor's preferred interest with equal principal payments due each quarter and the final payment in April 2003. In addition, we provided a financial guarantee of the Arctic Fox note payable to Snow Goose which, in turn, is the source of the priority returns. Based on the terms of the amendment, the remaining balance due of $224 million was classified as long-term debt due within one year on our Consolidated Balance Sheet at December 31, 2002. Priority returns prior to this amendment are included in preferred returns and minority interest in income of consolidated subsidiaries on the Consolidated Statement of Operations. Subsequent priority return payments are included in interest accrued on the Consolidated Statement of Operations.

In April 2003, we purchased the remaining outside investors' interest in Snow Goose.

PICEANCE PRODUCTION HOLDINGS LLC

In December 2001, we formed Piceance Production Holdings LLC (Piceance) and Rulison Production Company LLC (Rulison) in a series of transactions that resulted in the sale of a non-controlling preferred interest in Piceance to an outside investor for $100 million. We used the proceeds of the sale for general corporate purposes. The assets of Piceance included fixed-price overriding royalty interests in certain oil and gas properties owned by a subsidiary of ours as well as a $135 million note from Rulison. The outside investor was entitled to quarterly priority distributions beginning in January 2002, based upon an adjustable rate structure in addition to participation in a portion of the operating results of Piceance. At December 31, 2002, the obligation to the outside investor was $78.5 million and in May 2003, we purchased the remaining outside investors' interest in Piceance.

CASTLE ASSOCIATES L.P.

In December 1998, we formed Castle Associates L.P. (Castle) through a series of transactions that resulted in the sale of a non-controlling preferred interest in Castle to an outside investor for $200 million. We used the proceeds of the sale for general corporate purposes. The outside investor was entitled to quarterly priority distributions based upon an adjustable rate structure, in addition to a portion of the participation in the operating results of Castle. We purchased the outside investors' interest in December 2002.

WILLIAMS RISK HOLDINGS L.L.C.

During 1998, we formed Williams Risk Holdings L.L.C. (Holdings) in a series of transactions that resulted in the sale of a non-controlling preferred interest in Holdings to an outside investor for $135 million. We used the proceeds from the sale for general corporate purposes. The outside investor in Holdings was not a special purpose entity. The outside investor was entitled to monthly preferred distributions based upon an adjustable rate structure, in addition to participation in a portion of the operating results of Holdings. The initial priority return structure of Holdings was scheduled to expire in September 2003. In July 2002, following the downgrade of our senior unsecured rating we purchased the outside investor's ownership interest.

NOTE 13. STOCKHOLDERS' EQUITY

Concurrent with the sale of Kern River to MidAmerican Energy Holdings Company (MEHC) on March 27, 2002, we issued approximately 1.5 million shares of 9.875 percent cumulative convertible preferred stock to MEHC for $275 million. The terms of the preferred stock allowed the holder to convert, at any time, one share of preferred stock into 10 shares of our common stock at $18.75 per share. The preferred shares carried no voting rights and had a liquidation preference equal to the stated value of $187.50 per share plus any dividends accumulated and unpaid. Dividends on the preferred stock were payable quarterly. At the time the preferred stock was issued, the conversion price was less than the market price of our common stock and thus deemed beneficial to the purchaser. The benefit was recorded as a noncash dividend of $69.4 million, which was a reduction to our retained earnings with an offsetting amount recorded as an increase to capital in excess of par value.

On June 10, 2003, we redeemed all of the outstanding 9.875 percent cumulative-convertible preferred shares for approximately $289 million, plus $5.3 million for accrued dividends. The $13.8 million payments in excess of carrying value of the shares was also recorded as a dividend. These shares were repurchased with proceeds from a private placement of 5.5 percent junior subordinated convertible debentures due 2033 (see Note 11).

In January 2002, we issued $1.1 billion of 6.5 percent notes payable in 2007 which are subject to remarketing in 2004. Each note was bundled with an equity forward contract (together, the FELINE PACS units) and sold in a public offering for $25 per unit. The equity forward contract requires the holder of each note to purchase one share of our common stock for $25 three years from issuance of the contract, provided that the average price of our common stock does not exceed $41.25 per share for the 20 trading day period prior to settlement. If the average price over that period exceeds $41.25 per share, the number of shares issued in exchange for $25 will be equal to one share multiplied by the quotient of $41.25 divided by the average price over that period. For example, if the average price at settlement is $45 per share, the holder will be required to purchase .9166 of a share for $25. The holder of the equity forward contract can settle the contract early in the event we are involved in a merger in which at least 30 percent of the proceeds received by our shareholders is cash. In this event, the holder will be entitled to pay the purchase price and receive the kind and amount of securities they would have received had they settled the equity forward contract immediately prior to the acquisition. In addition to the 6.5 percent interest payment on the notes, we also make a 2.5 percent annual contract adjustment payment for the term of the equity forward contract. The present value of the total of the contract adjustment payments at the date the FELINE PACS were issued was $76.7 million and was recorded as a liability and a reduction to capital in excess of par at that time. A periodic charge is recognized in income to increase the value of the related liability as the date of the common stock issuance approaches.

We maintain a Stockholder Rights Plan under which each outstanding share of our common stock has one-third of a preferred stock purchase right attached. Under certain conditions, each right may be exercised to purchase, at an exercise price of $140 (subject to adjustment), one two-hundredth of a share of Series A Junior Participating Preferred Stock. The rights may be exercised only if an Acquiring Person acquires (or obtains the right to acquire) 15 percent or more of our common stock; or commences an offer for 15 percent or more of our common stock; or the Board of Directors determines an Adverse Person has become the owner of a substantial amount of our common stock. The rights, which until exercised do not have voting rights, expire in 2006 and may be redeemed at a price of $.01 per right prior to their expiration, or within a specified period of time after the occurrence of certain events. In the event a person becomes the owner of more than 15 percent of our common stock or the Board of Directors determines that a person is an Adverse Person, each holder of a right (except an Acquiring Person or an Adverse Person) shall have the right to receive, upon exercise, our common stock having a value equal to two times the exercise price of the right. In the event we are engaged in a merger, business combination or 50 percent or more of our assets, cash flow or earnings power is sold or transferred, each holder of a right (except an Acquiring Person or an Adverse Person) shall have the right to receive, upon exercise, common stock of the acquiring company having a value equal to two times the exercise price of the right.

NOTE 14. STOCK-BASED COMPENSATION

PLAN INFORMATION

On May 16, 2002, our stockholders approved The Williams Companies, Inc. 2002 Incentive Plan (the "Plan"). The Plan provides for common-stock-based awards to both employees and non-management directors. Upon approval by the stockholders, all prior stock plans were terminated resulting in no further grants being made from those plans. However, options outstanding in those prior plans remain in those plans with their respective terms and provisions.

The Plan permits the granting of various types of awards including, but not limited to, stock options, restricted stock and deferred stock. Awards may be granted for no consideration other than prior and future services or based on certain financial performance targets being achieved. At December 31, 2003, 56.2 million shares of our common stock were reserved for issuance pursuant to existing and future stock awards, of which 28.3 million shares were available for future grants (14.8 million at December 31, 2002).

LOANS

Several of our prior stock plans allowed us to loan money to participants to exercise stock options using stock certificates as collateral. Effective November 14, 2001, we no longer issue loans under the stock option loan programs. Loan holders were offered a one-time opportunity in January 2002 to refinance outstanding loans at a market rate of interest commensurate with the borrower's credit standing. The refinancing was in the form of a full recourse note, with interest payable annually in cash and a loan maturity date of December 31, 2005. We continue to hold the collateral shares and may review the borrower's financial position at any time. The variable rate of interest on the loans was determined at the signing of the promissory note to be 1.75 percent plus the current three-month London Interbank Offered Rate (LIBOR). The rate is subject to change every three months beginning with the first three-month anniversary of the note. The amount of loans outstanding at December 31, 2003 and 2002, totaled approximately $28 million (net of a $5 million allowance) and $30.3 million (net of a $5 million allowance), respectively.

DEFERRED SHARES

We granted deferred shares of approximately 158,000 in 2003, 2,738,000 in 2002 and 1,423,000 in 2001. Deferred shares are valued at the date of award, and the weighted-average grant date fair value of the shares granted was $4.68 in 2003, $12.26 in 2002 and $40.84 in 2001. We recognized approximately $30 million, $31 million and $22 million of expense for deferred shares, net of the reduction of expense from forfeited shares, in 2003, 2002 and 2001, respectively. Expense related to deferred shares granted is recognized in the performance year or over the vesting period, depending on the terms of the awards. The reduction of expense related to the deferred shares forfeited is recognized in the year of the forfeiture. We issued approximately 1,329,000 in 2003, 499,000 in 2002 and 260,000 in 2001, of the deferred shares previously granted.

OPTIONS

The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant. Stock options generally become exercisable after three years from the date of grant and generally expire ten years after grant.

On May 15, 2003, our shareholders approved a stock option exchange program. Under this program, eligible employees were given a one-time opportunity to exchange certain outstanding options for a proportionately lesser number of options at an exercise price to be determined at the grant date of the new options. Surrendered options were cancelled June 26, 2003, and replacement options were granted on December 29, 2003. We did not recognize any expense pursuant to the stock option exchange. However, for purposes of pro forma disclosures, we recognized additional expense related to these new options. The remaining expense on the cancelled options will be amortized through year-end 2004.

The following summary reflects stock option activity for our common stock and related information for 2003, 2002 and 2001:

	2003		2002		2001	
	OPTIONS	WEIGHTED-AVERAGE EXERCISE PRICE	OPTIONS	WEIGHTED-AVERAGE EXERCISE PRICE	OPTIONS	WEIGHTED-AVERAGE EXERCISE PRICE
	(MILLIONS)		(MILLIONS)		(MILLIONS)	
Outstanding -- beginning of year....	38.8	$ 19.85	25.6	$ 28.23	23.1	$ 28.63
Granted............................	4.1*	9.76	15.8	6.64	4.8	37.45
Exercised..........................	(.2)	5.86	(.5)	11.77	(3.3)	18.47
Barrett option conversions..........	--	--	--	--	2.0	21.57
Adjustment for WilTel spinoff(1)..........................	--	--	--	--	2.1	--
Canceled...........................	(17.0)**	25.60	(2.1)	26.31	(3.1)	32.35
Outstanding -- end of year..........	25.7	$ 14.63	38.8	$ 19.85	25.6	$ 28.23
Exercisable -- end of year..........	12.3	$ 24.23	21.7	$ 27.42	20.0	$ 26.41

* Includes 3.9 million shares that were granted December 29, 2003, under the stock option exchange program, described above.

** Includes 10.4 million shares that were cancelled on June 26, 2003 under the stock option exchange program, described above.

(1) Effective with the spinoff of WilTel on April 23, 2001, the number and exercise price of unexercised stock options were adjusted to preserve the intrinsic value of the stock options that existed prior to the spinoff.

The following summary provides information about options for our common stock that are outstanding and exercisable at December 31, 2003:

	STOCK OPTIONS OUTSTANDING			STOCK OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	OPTIONS	WEIGHTED-AVERAGE EXERCISE PRICE	WEIGHTED-AVERAGE REMAINING CONTRACTUAL LIFE	OPTIONS	WEIGHTED-AVERAGE EXERCISE PRICE
	(MILLIONS)			(MILLIONS)	
$1.35 to $5.40.................	10.0	$ 2.82	8.7 years	1.2	$ 4.28
$6.96 to $9.70.................	.8	8.68	1.1 years	.8	8.68
$10.00 to $12.22...............	4.5	10.21	5.2 years	.7	11.40
$12.59 to $31.56...............	5.8	20.39	3.4 years	5.2	20.86
$33.51 to $42.52...............	4.6	37.74	3.8 years	4.4	37.87
Total........................	25.7	$ 14.63	5.8 years	12.3	$ 24.23

The estimated fair value at date of grant of options for our common stock granted in 2003, 2002 and 2001, using the Black-Scholes option pricing model, is as follows:

	2003*	2002	2001
Weighted-average grant date fair value of options for our common stock granted during the year	$ 2.95	$ 2.77	$ 10.93
Assumptions:			
Dividend yield	1%	1%	1.9%
Volatility	50%	56%	35%
Risk-free interest rate	3.1%	3.6%	4.8%
Expected life (years)	5.0	5.0	5.0

* The 2003 weighted average fair value and assumptions do not reflect options that were granted December 29, 2003, as part of the stock option exchange program which is described above. The fair value of these options is $1.58, which is the difference in the fair value of the new options granted and the fair value of the exchanged options. The assumptions used in the fair value calculation of the new options granted were: 1) dividend yield of .40 percent; 2) volatility of 50 percent; 3) weighted average expected remaining life of 3.4 years; and 4) weighted average risk free interest rate of 1.99 percent.

Pro forma net income (loss) and earnings per share, assuming we had applied the fair-value method of SFAS No. 123, "Accounting for Stock-Based Compensation" in measuring compensation cost beginning with 1997 employee stock-based awards is disclosed under Employee stock-based awards in Note 1.

NOTE 15. FINANCIAL INSTRUMENTS, DERIVATIVES, GUARANTEES AND CONCENTRATION OF CREDIT RISK

FINANCIAL INSTRUMENTS FAIR VALUE

Fair-value methods

We used the following methods and assumptions in estimating our fair-value disclosures for financial instruments:

Cash and Cash Equivalents and Restricted Cash: The carrying amounts reported in the balance sheet approximate fair value due to the short-term maturity of these instruments.

Notes and Other Non-current Receivables, Margin Deposits and Deposits Received from Customers Relating to Energy Trading and Hedging Activities: The carrying amounts reported in the balance sheet approximate fair value as these instruments have interest rates approximating market or maturities of less than three years.

Restricted Investments and Marketable Equity Securities: The restricted investments consist of short-term U.S. Treasury securities. Fair value is determined using indicative year-end traded prices.

Advances to Affiliates: The 2003 carrying amounts reported in the balance sheet approximate fair value as these instruments were written down to estimated fair value based on terms of a recapitalization plan (see Note 3). The 2002 carrying amounts, reported in the balance sheet in Investments approximate fair value as these instruments have interest rates approximating market.

Notes Payable: Fair value of the RMT note payable in 2002 was determined using the expertise of outside investment banking firms. The carrying amounts of other notes payable approximate fair value due to the short-term maturity of these instruments.

Long-Term Debt: The fair value of our publicly traded long-term debt is valued using indicative year-end traded bond market prices. Private debt is valued based on the prices of similar securities with similar terms and credit ratings. At December 31, 2003 and 2002, 77 percent and 76 percent, respectively, of our long-term debt was publicly traded. We used the expertise of outside investment banking firms to assist with the estimate of the fair value of long-term debt.

Energy Derivatives: Energy derivatives include:

- futures contracts,
- forward purchase and sale contracts,
- swap agreements,
- option contracts,
- interest-rate swap agreements and futures contracts, and
- credit default swaps.

Fair value of energy derivatives is determined based on the nature of the transaction and the market in which transactions are executed. Most of these transactions are executed in exchange-traded or over-the-counter markets for which quoted prices in active periods exist. For contracts with lives exceeding the time period for which quoted prices are available, we determined fair value by estimating commodity prices during the illiquid periods. We estimated commodity prices during illiquid periods by incorporating information obtained from commodity prices in actively quoted markets, prices reflected in current transactions and market fundamental analysis.

Foreign Currency Derivatives: Fair value is determined by discounting estimated future cash flows using forward foreign exchange rates derived from the year-end forward exchange curve. Fair value was calculated by the financial institution that is counterparty to the agreement.

Interest-Rate Swaps: Fair value is determined by discounting estimated future cash flows using forward-interest rates derived from the year-end yield curve. The financial institutions that are the counterparties to the swaps calculated the fair value.

Carrying Amounts and Fair Values of Our Financial Instruments

ASSET (LIABILITY)	2003 CARRYING AMOUNT	2003 FAIR VALUE	2002 CARRYING AMOUNT	2002 FAIR VALUE
	(MILLIONS)			
Cash and cash equivalents	$ 2,315.7	$ 2,315.7	$ 1,650.4	$ 1,650.4
Restricted cash (current and noncurrent)	206.9	206.9	290.9	290.9
Notes and other noncurrent receivables	140.0	140.0	164.9	164.9
Investments:				
Cost based investments	112.7	(a)	163.9	(a)
Restricted investments (current and noncurrent)	381.3	381.3	--	--
Marketable equity securities	--	--	13. 7	13.7
Advances to affiliates	117.2	117.2	100.9	100.9
Notes payable	(3.3)	(3.3)	(996.3)	(1,063.1)
Long-term debt, including current portion	(11,975.0)	(12,281.5)	(12,016.7)	(8,505.5)
Margin deposits	553.9	553.9	804.8	804.8
Deposits received from customers relating to energy risk management and trading and hedging activities	(25.8)	(25.8)	(141.2)	(141.2)
Guarantees	46.8	(b)	65.7	(b)
Energy derivatives:				
Energy trading and non-trading derivatives	845.9	845.9	465.9	465.9
Energy commodity cash flow and fair-value hedges	(296.4)	(296.4)	49.3	49.3
Foreign currency derivatives	(55.2)	(55.2)	24.0	24.0
Interest-rate swaps	(20.2)	(20.2)	(27.9)	(27.9)

(a) These investments are primarily in non-publicly traded companies for which it is not practicable to estimate fair value.

(b) It is not practicable to estimate the fair value of these financial instruments because of their unusual nature and unique characteristics.

ENERGY DERIVATIVES

Energy trading and non-trading derivatives

We have energy trading and non-trading derivatives that have not been designated as or do not qualify as SFAS No. 133 hedges. As such, the net change in their fair value is recognized in earnings. Our Power segment has trading derivatives that provide risk management services to our third-party customers and non-trading derivatives that hedge or could possibly hedge our long-term structured contract positions on an economic basis. In addition, our Exploration & Production segment enters into natural gas basis swap agreements and the Alaska operations (within discontinued operations) enters into crude oil and refined product contracts.

We also hold significant non-derivative energy-related contracts in our Power trading and non-trading portfolios. These have not been included in the financial instruments table above because they do not qualify as financial instruments. See Note 1 regarding Energy commodity risk management and trading activities and revenues for further discussion of the non-derivative energy-related contracts.

POWER SEGMENT

Futures Contracts: Futures contracts are commitments to either purchase or sell a commodity at a future date for a specified price and are generally settled in cash, but may be settled through delivery of the underlying commodity. Exchange-traded or over-the-counter markets providing quoted prices in active periods are available. Where quoted prices are not available, other market indicators exist for the futures contracts we enter into. The fair value of these contracts is based on quoted prices.

Swap Agreements and Forward Purchase and Sale Contracts: Swap agreements require us to make payments to (or receive payments from) counterparties based upon the differential between a fixed and variable price or variable prices of energy commodities for different locations. Forward contracts which involve physical delivery of energy commodities contain both fixed and variable pricing terms. Swap agreements and forward contracts are valued based on prices of the underlying energy commodities over the contract life and contractual or notional volumes with the resulting expected future cash flows discounted to a present value using a risk-free market interest rate.

Options: Physical and financial option contracts give the buyer the right to exercise the option and receive the difference between a predetermined strike price and a market price at the date of exercise. These contracts are valued based on option pricing models considering prices of the underlying energy commodities over the contract life, volatility of the commodity prices, contractual volumes, estimated volumes under option and other arrangements and a risk-free market interest rate.

Interest-Rate and Credit Derivatives: Interest-rate swap and futures agreements, including those with the parent, are used to manage the interest rate risk in Power's energy trading and non-trading portfolio. Under swap agreements, Power pays a fixed rate and receives a variable rate on the notional amount of the agreements. Financial futures contracts are commitments to either purchase or sell a financial instrument, such as a Eurodollar deposit, U.S. Treasury bond or U.S. Treasury note, at a future date for a specified price. These are generally settled in cash, but may be settled through delivery of the underlying instrument. The fair value of these contracts is determined by discounting estimated future cash flows using forward interest rates derived from interest rate yield curves. Credit default swaps are used to manage counterparty credit exposure in the energy trading and non-trading portfolio. Under these agreements, Power pays a fixed rate premium for a notional amount of risk coverage associated with certain credit events. The covered credit events are bankruptcy, obligation acceleration, failure to pay and restructuring. The fair value of these agreements is based on current pricing received from the counterparties.

The valuation of all the contracts discussed above also considers factors such as the liquidity of the market in which the contract is transacted, uncertainty regarding the ability to liquidate the position considering market factors applicable at the date of such valuation and risk of non-performance and credit considerations of the counterparty. For contracts or transactions that extend into periods for which actively quoted prices are not available, we estimate energy commodity prices in the illiquid periods by incorporating information obtained from commodity prices in actively quoted markets, prices reflected in current transactions and market fundamental analysis.

EXPLORATION & PRODUCTION SEGMENT

Our operations associated with the production of natural gas enter into basis swap agreements fixing the price differential between the Rocky Mountain natural gas prices and Gulf Coast natural gas prices as part of their overall natural gas price risk management program to reduce risk of declining natural gas prices in basins with limited pipeline capacity to other markets. Certain of these basis swaps do not qualify for hedge accounting treatment under SFAS No. 133; hence, the net change in fair value of these derivatives representing unrealized gains and losses is recognized in earnings currently as revenues in the Consolidated Statement of Operations.

DISCONTINUED OPERATIONS

During 2002 and early 2003, our operations associated with crude oil refining and refined products marketing in the Midsouth entered into derivative transactions (primarily forward contracts, futures contracts, swap agreements and option contracts) which were not designated as hedges. The forward contracts were for the procurement of crude oil and refined products supply for operational purposes, while the other derivatives manage certain risks associated with market fluctuations in crude oil and refined product prices related to refined products marketing. The net change in fair value of these derivatives, representing unrealized gains and losses, was recognized in earnings currently as revenues or costs and operating expenses in the Consolidated Statement of Operations. As a result of the completion of the sale of the Midsouth refinery during first-quarter 2003, these derivatives were discontinued.

Energy commodity cash flow hedges

We are also exposed to market risk from changes in energy commodity prices within other areas of our operations. We utilize derivatives to manage our exposure to the variability in expected future cash flows attributable to commodity price risk associated with forecasted purchases and sales of natural gas, refined products and crude oil. These derivatives have been designated as cash flow hedges.

We produce, buy and sell natural gas and crude oil at different locations throughout the United States. To reduce exposure to a decrease in revenues or an increase in costs from fluctuations in natural gas and crude oil market prices, we enter into natural gas and crude oil futures contracts and swap agreements to fix the price of anticipated sales and purchases of natural gas and sales of crude oil. During 2003, we discontinued hedge accounting for anticipated sales of crude oil due to the sale of those producing properties.

Our refinery operations purchase crude oil for processing and sell the refined products. These operations are exposed to increasing costs of crude oil and/or decreasing refined product sales prices due to changes in market prices. We enter into crude oil and refined products futures contracts and swap agreements to lock in the prices of anticipated purchases of crude oil and sales of refined products. During 2002, these derivatives were accounted for as cash flow hedges. Hedge accounting was discontinued during 2002 for forecasted transactions no longer probable of occurring because of the anticipated sales of the refineries (see Note 2).

Our electric generation facilities utilize natural gas in the production of electricity. To reduce the exposure to increasing costs of natural gas due to changes in market prices, we enter into natural gas futures contracts and swap agreements to fix the prices of anticipated purchases of natural gas. In addition, during 2002 we entered into fixed-price forward physical contracts to fix the prices of anticipated sales of electric production. During 2002, we discontinued hedge accounting for one of the electric generation facilities due to the sale of the facility in 2003.

Derivative gains or losses from these cash flow hedges are deferred in other comprehensive income and reclassified into earnings in the same period or periods during which the hedged forecasted purchases or sales affect earnings. To match the underlying transaction being hedged, derivative gains or losses associated with anticipated purchases are recognized in costs and operating expenses and amounts associated with anticipated sales are recognized in revenues in the Consolidated Statement of Operations. Approximately $.6 million of gains from hedge ineffectiveness are included in costs and operating expenses in the Consolidated Statement of Operations during 2003. Approximately $.5 million of losses and $.7 million of gains from hedge ineffectiveness are included in revenues and costs and operating expenses, respectively, in the Consolidated Statement of Operations during 2002. We discontinued hedge accounting in 2003 and 2002 for certain contracts when it became probable that the related forecasted transactions would not occur. As a result, we reclassified net losses of $5 million and net gains of $43 million from accumulated other comprehensive income and into earnings in the Consolidated Statement of Operations in 2003 and 2002, respectively. For 2003 and 2002, there were no derivative gains or losses excluded from the assessment of hedge effectiveness. As of December 31, 2003, we had hedged future cash flows associated with anticipated energy commodity purchases and sales for up to 12 years. Based on recorded values at December 31, 2003, approximately $104 million of net losses (net of income tax benefits of $65 million) will be reclassified into earnings within the next year. These losses will offset net gains that will be realized in earnings from previous favorable market movements associated with underlying hedged transactions.

Energy commodity fair-value hedges

Our refineries carry inventories of crude oil and refined products. During 2002, we entered into crude oil and refined products futures contracts and swap agreements to reduce the market exposure of these inventories from changing energy commodity prices. These derivatives were designated as fair-value hedges. Derivative gains and losses from these fair-value hedges were recognized in earnings currently along with the change in fair value of the hedged item attributable to the risk being hedged. Gains and losses related to hedges of inventory were recognized in costs and operating expenses in the Consolidated Statement of Operations. Approximately $8 million of net gains from hedge ineffectiveness was recognized in costs and operating expenses in the Consolidated Statement of Operations during 2002. There were no derivative gains or losses excluded from the assessment of hedge effectiveness. During third-quarter 2002, we discontinued the use of fair value hedges related to refined products and crude oil in early 2003 due to the sale of the Midsouth refinery.

FOREIGN CURRENCY DERIVATIVES

We have an intercompany Canadian-dollar-denominated note receivable that is exposed to foreign-currency risk. To protect against variability in the cash flows from the repayment of the note receivable associated with changes in foreign currency exchange rates, we entered into a forward contract to fix the U.S. dollar principal cash flows from this note. This derivative was designated as a cash flow hedge and was expected to be highly effective over the period of the hedge. Hedge accounting was discontinued effective October 1, 2002 because the hedge is no longer expected to be highly effective. All gains or losses subsequent to October 1, 2002, are recognized currently in other income (expense) -- net below operating income. Gains and losses from the change in fair value of the derivatives prior to October 1, 2002, were deferred in other comprehensive income (loss) and reclassified to other income (expense) -- net below operating income as the Canadian-dollar-denominated note receivable impacted earnings as it was translated into U.S. dollars. The $2.4 million of net losses (net of income tax benefits of $1.5 million) deferred in other comprehensive income (loss) at December 31, 2002, was reclassified into earnings during 2003. In 2002, there were no derivative gains or losses recorded in the Consolidated Statement of Operations from hedge ineffectiveness or from amounts excluded from the assessment of hedge effectiveness, and no foreign currency hedges were discontinued as a result of it becoming probable that the forecasted transaction would not occur.

INTEREST-RATE SWAPS

We managed our interest rate risk on an enterprise basis through the corporate parent. A significant component of this risk relates to our Power segment's trading and non-trading portfolios. To facilitate the management of the risk, Power may enter into derivative instruments (usually swaps) with the corporate parent. The corporate parent determines the level, term and nature of derivative instruments entered into with external parties. These external derivative instruments do not qualify for hedge accounting per SFAS No. 133; therefore, changes in their fair value are reflected in earnings, the effect of which is shown as interest rate swap loss in the Consolidated Statement of Operations below operating income.

GUARANTEES

In addition to the guarantees and payment obligations discussed elsewhere in these footnotes (see Notes 2, 3, 11 and 16), we have issued guarantees and other similar arrangements with off-balance sheet risk as discussed below.

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 exceed the minimum purchase price.

SALE OF RECEIVABLES

Through July 25, 2002 we sold certain trade accounts receivable to special purpose entities (SPEs) in a securitization structure. We acted as the servicing agent for the sold receivables and received a servicing fee approximating the fair value of such services. During 2002 and 2001, we received cash proceeds from the SPEs of approximately $4.5 billion and $12.5 billion, respectively. The sales of these receivables resulted in charges to results of operations of approximately $3 million and $16 million in 2002 and 2001, respectively.

CONCENTRATION OF CREDIT RISK

Cash equivalents and restricted investments

Our cash equivalents consist of high-quality securities placed with various major financial institutions with credit ratings at or above BBB by Standard & Poor's or Baa1 by Moody's Investors Service. Restricted investments consist of short-term U.S. Treasury Securities.

Accounts and notes receivable

The following table summarizes concentration of receivables, net of allowances, by product or service at December 31, 2003 and 2002:

	2003	2002
	(MILLIONS)	
Receivables by product or service:		
Sale or transportation of natural gas and related products	$ 793.9	$ 910.0
Power sales and related services	704.9	1,009.1
Sale or transportation of petroleum products	29.2	276.9
Income taxes receivable	17.5	152.0
Other	67.7	39.1
Total	$1,613.2	$2,387.1

Natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the eastern and northwestern United States, Rocky Mountains, Gulf Coast, Venezuela and Canada. Power customers include the California Independent System Operator (ISO), the California Department of Water Resources, other power marketers and utilities located throughout the majority of the United States. Petroleum products customers include wholesale, commercial, industrial and independent dealers located primarily in the Mid-Continent region. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly.

As of December 31, 2003, approximately $177 million of certain power receivables net of related allowances from the ISO and the California Power Exchange have not been paid (compared to $230 million at December 31, 2002). We believe that we have appropriately reflected the collection and credit risk associated with receivables and derivative assets in our Consolidated Balance Sheet and Statement of Operations at December 31, 2003. In 2002, we borrowed approximately $79 million which was collateralized by certain of these receivables.

Derivative assets and liabilities

We have a risk of loss as a result of counterparties not performing pursuant to the terms of their contractual obligations. Risk of loss can result from credit considerations and the regulatory environment of the counterparty. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances.

The concentration of counterparties within the energy and energy trading industry impacts our overall exposure to credit risk in that these counterparties are similarly influenced by changes in the economy and regulatory issues. Additional collateral support could include the following:

- letters of credit,
- payment under margin agreements,
- guarantees of payment by credit worthy parties, and
- transfers of ownership interests in natural gas reserves or power generation assets.

We also enter into netting agreements to mitigate counterparty performance and credit risk.

The gross credit exposure from our derivative contracts as of December 31, 2003 is summarized below.

COUNTERPARTY TYPE	INVESTMENT GRADE(a)	TOTAL
	(MILLIONS)	
Gas and electric utilities	$ 988.2	$ 1,045.9
Energy marketers and traders	1,317.2	3,118.5
Financial Institutions	918.5	918.5
Other	609.8	619.3
	$ 3,833.7	5,702.2
Credit reserves		(39.8)
Gross credit exposure from derivatives(b)		$ 5,662.4

We assess our credit exposure on a net basis. The net credit exposure from our derivatives as of December 31, 2003 is summarized below.

COUNTERPARTY TYPE	INVESTMENT GRADE(a)	TOTAL
	(MILLIONS)	
Gas and electric utilities	$ 606.1	$ 629.4
Energy marketers and traders	52.1	376.3
Financial Institutions	160.4	160.4
Other	--	.2
	$ 818.6	1,166.3
Credit reserves		(39.8)
Net credit exposure from derivatives(b)		$ 1,126.5

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(a) We determine investment grade primarily using publicly available credit ratings. We included counterparties with a minimum Standard & Poor's 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, parent company guarantees, and property interests, as investment grade.

(b) One counterparty within the California power market represents more than ten percent of the derivative assets and is included in investment grade. Standard & Poor's and Moody's Investors Service do not currently rate this counterparty. We included this counterparty in the investment grade column based upon contractual credit requirements in the event of assignment or substitution of a new obligation for the existing one.

Revenues

In 2003, there were no customers that exceeded 10 percent of our revenues. In 2002, eight of Power's customers exceeded 10 percent of our revenues with sales from each customer of $516.9 million, $505.5 million, $482.5 million, $474.8 million, $408.7 million, $379.2 million, $377.5 million and $358.9 million, respectively. The revenues from these customers in 2002 are net of cost of sales with the same customer consistent with fair-value accounting (see Note 1). The sum of these net revenues exceeds our total revenues because there are additional customers with whom we have negative net revenues (due to the costs from these customers exceeding the revenues) which offset this sum. In 2001, three of Power's customers exceeded 10 percent of our revenues with sales of $937.7 million, $597.9 million and $501 million, respectively.

Certain of our counterparties have experienced significant declines in their financial stability and creditworthiness, which may adversely impact their ability to perform under contracts. Revenues from two counterparties, which have credit ratings below investment grade, constitute approximately 12 percent of Power's gross revenues. Our exposure to these counterparties may be mitigated by the existence of netting arrangements.

NOTE 16. CONTINGENT LIABILITIES AND COMMITMENTS

RATE AND REGULATORY MATTERS AND RELATED LITIGATION

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result of rulings in certain of these proceedings, a portion of the revenues of these subsidiaries has been collected subject to refund. The natural gas pipeline subsidiaries have accrued approximately $11 million for potential refund as of December 31, 2003.

ISSUES RESULTING FROM CALIFORNIA ENERGY CRISIS

Power subsidiaries are 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 have been challenged in various proceedings including those before the FERC. These challenges include refund proceedings, California Independent System Operator (ISO) fines, 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 a settlement with the State of California and others that has resolved each of these issues as to the State. However, certain of these issues remain open as to the FERC and other non-settling parties.

Refund proceedings

We and other suppliers of electricity in the California market are the subject of refund proceedings before the FERC. In December 2000, the FERC issued an order initiating the proceeding, which ultimately (by order dated June 19, 2001) established a refund methodology and set a refund period of October 2, 2000 to June 19, 2001. As a result of a hearing to determine refund liability for the market participants, a FERC Administrative Law Judge issued findings on December 12, 2002, that estimated our refund obligation to the ISO at $192 million, excluding emissions costs and interest. The judge estimated that our refund obligation to the California Power Exchange (PX) was $21.5 million, excluding interest. However, the judge estimated that the ISO owes us $246.8 million, excluding interest, and that the PX owes us $31.7 million, excluding interest, and $2.9 million in charge backs. The estimates did not include $17 million in emissions costs that the judge found we are entitled to use as an offset to the refund liability, and the judge's refund estimates are not based on final mitigated market clearing prices. On March 26, 2003, the FERC acted to largely adopt the judge's order with a change to the gas methodology used to set the clearing price. As a result, Power recorded a first-quarter 2003 charge for refund obligations of $37 million. Net interest income related to amounts due from the counterparties is approximately $19 million through December 31, 2003. On October 16, 2003, the FERC issued an additional refund order granting rehearing in part and denying rehearing in part. This order is not expected to have a material effect on the refund calculation for us. However, pursuant to the October 16 Order, the ISO has been ordered to calculate refunds for the market. This study is expected to be complete in early summer, 2004. Although we have entered into a global settlement with the State of California and various other parties that resolves the refund issues among the settling parties for the period of January 17, 2001 to June 19, 2001, we have potential refund exposure to non-settling parties (e.g., various California electric utilities). Therefore, we continue to participate in the FERC refund case and related proceedings. Challenges to virtually every aspect of the refund proceeding, including the refund period, are now pending at the Ninth Circuit Court of Appeals. No schedule has yet been established for hearing the appeals.

On February 25, 2004, we announced a settlement agreement with California utilities, Southern California Edison and Pacific Gas & Electric (PG&E), to resolve our refund liability to the utilities as well as all other known disputes related to the California energy crisis of 2000 and 2001. While only these two utilities are parties to the settlement with us, the settlement provides funding for refunds to all buyers in equal kind in the FERC refund period. Should any buyer opt out of the settlement, the refund amount in the settlement would be reduced and we would continue to litigate with that buyer regarding the refund issue and amount. To be effective, this settlement must be approved by the FERC, the California Public Utilities Commission, and the U.S. Bankruptcy Court for PG&E. Approval by the FERC will also resolve FERC investigations into physical and economic withholding. We recorded a charge of approximately $33 million in the fourth quarter of 2003 associated with the terms of this settlement.

In a separate but related proceeding, certain entities have also asked the FERC to revoke our authority to sell power from California-based generating units at market-based rates, to limit us to cost-based rates for future sales from such units and to order refunds of excessive rates, with interest, retroactive to May 1, 2000, and possibly earlier.

ISO fines

On July 3, 2002, the ISO announced fines against several energy producers including us, for failure to deliver electricity during the period December 2000 through May 2001. The ISO fined us $25.5 million during this period, which was offset against our claims for payment from the ISO. These amounts will be adjusted as part of the refund proceeding described above. We believe the vast majority of fines are not justified and have challenged them pursuant to the FERC-approved dispute resolution process contained in the ISO tariff.

Summer 2002 90-day contracts

On May 2, 2002, PacifiCorp filed a complaint with the FERC against Power seeking relief from rates contained in three separate confirmation agreements between PacifiCorp and Power (known as the Summer 2002 90-Day Contracts). PacifiCorp filed similar complaints against three other suppliers. PacifiCorp alleged that the rates contained in the contracts are unjust and unreasonable. On June 26, 2003, the FERC affirmed the Administrative Law Judge's initial decision dismissing the complaints. PacifiCorp has appealed the FERC's order after the FERC denied rehearing of its order on November 10, 2003.

Investigations of alleged market manipulation

As a result of various allegations and FERC Orders, the FERC initiated investigations of manipulation of the California gas and power markets in 2002. As they related to us, these investigations included economic and physical withholding, so-called "Enron Gaming Practices" and gas index manipulation.

On February 13, 2002, the FERC issued an Order Directing Staff Investigation commencing a proceeding titled Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices prior to the California parties (who include the California Attorney General, the Electricity Oversight Board, the Public Utilities Commission and two investor-owned utilities) filing of their report. Through the investigation, the FERC intends to determine whether "any entity, including Enron Corporation (Enron) (through any of its affiliates or subsidiaries), manipulated short-term prices for electric energy or natural gas in the West or otherwise exercised undue influence over wholesale electric prices in the West since January 1, 2000, resulting in potentially unjust and unreasonable rates in long-term power sales contracts subsequently entered into by sellers in the West." On May 8, 2002, we received data requests from the FERC related to a disclosure by Enron of certain trading practices in which it may have been engaged in the California market. On May 21, and May 22, 2002, the FERC supplemented the request inquiring as to "wash" or "round-trip" transactions. We responded on May 22, 2002, May 31, 2002, and June 5, 2002, to the data requests. On June 4, 2002, the FERC issued an order to us to show cause why our market-based rate authority should not be revoked as the FERC found that certain of our responses related to the Enron trading practices constituted a failure to cooperate with the staff's investigation. We subsequently supplemented our responses to address the show cause order. On July 26, 2002, we received a letter from the FERC informing us that it had reviewed all of our supplemental responses and concluded that we responded to the initial May 8, 2002 request.

As also discussed below in REPORTING OF NATURAL GAS-RELATED INFORMATION TO TRADE PUBLICATIONS, on November 8, 2002, we received a subpoena from a federal grand jury in Northern California seeking documents related to our involvement in California markets. We are in the process of completing our response to the subpoena. This subpoena is a part of the broad United States Department of Justice (DOJ) investigation regarding gas and power trading.

Pursuant to an order from the Ninth Circuit, the FERC permitted certain California parties to conduct additional discovery into market manipulation by sellers in the California markets. The California parties sought this discovery in order to potentially expand the scope of the refunds. On March 3, 2003, the California parties submitted evidence from this discovery on market manipulation ("March 3rd Report"). We and other sellers submitted comments regarding the additional evidence on March 20, 2003.

On March 26, 2003, the FERC issued a Staff Report addressing: (1) Enron trading practices, (2) an allegation in a June 2, 2002 New York Times article that we had attempted to corner the gas market, and (3) the allegations of gas price index manipulation which are discussed in more detail below in REPORTING OF NATURAL GAS-RELATED INFORMATION TO TRADE PUBLICATIONS. The Staff Report cleared us on the issue of cornering the market and contemplated or established further proceedings on the other two issues as to us and numerous other market participants. On June 25, 2003, the FERC issued a series of orders in response to the California parties' March 3rd Report and the Staff Report. These orders resulted in further investigations regarding potential allegations of physical withholding, economic withholding, and a show cause order alleging that various companies engaged in Enron trading practices. On August 29, 2003, we entered into a settlement with the FERC trial staff of all Enron trading practices for approximately $45,000. The settlement was approved by the FERC on January 22, 2004. The investigations of physical and economic withholding are also continuing. Each of these FERC investigations of alleged market manipulation will be resolved pursuant to the February 25 settlement that is discussed above in Refund proceedings.

Long-term contracts

In February 2001, during the height of the California Energy Crisis, we entered into a long-term power contract with the State of California to assist in stabilizing its market. This contract was later challenged by the State of California. This challenge resulted in settlement discussions being held between the State and us on the contract issue as well as other state initiated proceedings and allegations on market manipulation. A settlement was reached that resulted in us entering into a settlement agreement with the State of California and other non-Federal parties that includes renegotiated long-term energy contracts. These contracts are made up of block energy sales, dispatchable products and a gas contract. The settlement does not extend to criminal matters or matters of willful fraud, but also resolved civil complaints brought by the California Attorney General against us and the State of California's refund claims that are discussed above. In addition, the settlement resolved ongoing investigations by the States of California, Oregon and Washington. The settlement was reduced to writing and executed on November 11, 2002. The settlement closed on December 31, 2002, after FERC issued an order granting our motion for partial dismissal from the refund proceedings. The dismissal affects our refund obligations to the settling parties, but not to other parties, such as investor-owned utilities. Pursuant to the settlement, the California Public Utilities Commission (CPUC) and California Electricity Oversight Board (CEOB) filed a motion on January 13, 2003 to withdraw their complaints against us regarding the original block energy sales contract. On June 26, 2003, the FERC granted the CPUC and CEOB joint motion to withdraw their respective complaints against us. Certain private class action and other civil plaintiffs who have initiated class action litigation against us and others in California based on allegations against us with respect to the California energy crisis also executed the settlement. Final approval by the court is needed to make the settlement effective as to plaintiffs and to terminate the class actions as to us. On October 24, 2003, the court granted a motion for preliminary approval of the settlement. The final approval hearing is currently scheduled for June 4, 2004. Upon approval, the majority of civil litigation involving Williams and California markets will be resolved. Some litigation by non-California plaintiffs, or relating to reporting of natural gas information to trade publications, as discussed below, will continue. As of December 31, 2003, pursuant to the terms of the settlement, we have transferred ownership of six LM6000 gas powered electric turbines, have made two payments totaling $72 million to the California Attorney General, and have funded a $15 million fee and expense fund associated with civil actions that are subject to the settlement. An additional $75 million remains to be paid to the California Attorney General (or his designee) over the next six years, with the final payment of $15 million due on January 1, 2010.

MARKETING AFFILIATE INVESTIGATION

By order dated March 17, 2003, the FERC approved a settlement between the FERC staff and us, Transco, and Power which resolved the FERC staff's allegations during a formal, nonpublic investigation that Power personnel had access to Transco data bases and other information, and that Transco had failed to accurately post certain information on its electronic bulletin board. Pursuant to the terms of the settlement agreement, Transco will pay a civil penalty in the amount of $20 million in five equal installments. The first payment was made on May 16, 2003, and the subsequent payments are due on or before the first, second, third and fourth anniversaries of the first payment. Transco recorded a charge to income and established a liability of $17 million in 2002 representing the net present value of the future payments. Transco notified its Firm Sales (FS) customers of its intention to terminate the FS service effective April 1, 2005 under the terms of any applicable contracts and FERC certificates authorizing such services. As part of the settlement, Power has agreed, subject to certain exceptions, that it will not enter into new transportation agreements that would increase the transportation capacity it holds on certain affiliated interstate gas pipelines, including Transco. Finally, Transco and certain affiliates have agreed to the terms of a compliance plan designed to ensure future compliance with the provisions of the settlement agreement and the FERC's rules governing the relationship of Transco and Power.

INVESTIGATION OF "ROUND-TRIP" TRADING AND RESERVES FOR ENERGY TRADING ACTIVITIES

On May 31, 2002, we received a request from the Enforcement Division of the Securities and Exchange Commission (SEC) to voluntarily produce documents and information regarding "round-trip" trades for gas or power from January 1, 2000, to the present in the United States. On June 24, 2002, the SEC made an additional request for information including a request that we address the amount of our credit, prudency and/or other reserves associated, with our energy trading activities and the methods used to determine or calculate these reserves. The June 24, 2002, request also requested our volumes, revenues, and earnings from our energy trading activities in the Western U.S. market. We have responded to the SEC's requests and have received no further related requests from them to date.

REPORTING OF NATURAL GAS-RELATED INFORMATION TO TRADE PUBLICATIONS

We disclosed on October 25, 2002, that certain of our natural gas traders had reported inaccurate information to a trade publication that published gas price indices. As noted above, on November 8, 2002, we received a subpoena from a federal grand jury in Northern California seeking documents related to our involvement in California markets, including our reporting to trade publications for both gas and power transactions. We are in the process of completing our response to the subpoena. The DOJ's investigation into this matter is continuing. In addition, the Commodity Futures Trading Commission (CFTC) has conducted an investigation of us regarding this issue. On July 29, 2003, we reached a settlement with the CFTC where in exchange for $20 million, the CFTC closed its investigation and we did not admit or deny allegations that we had engaged in false reporting or attempted manipulation. Civil suits based on allegations of manipulating the gas indices have been brought against us and others in federal and state court in California and in Federal court in New York.

MOBILE BAY EXPANSION

On December 3, 2002, an administrative law judge at the FERC issued an initial decision in Transco's general rate case which, among other things, rejects the recovery of the costs of Transco's Mobile Bay expansion project from its shippers on a "rolled-in" basis and finds that incremental pricing for the Mobile Bay expansion project is just and reasonable. The initial decision does not address the issue of the effective date for the change to incremental pricing, although Transco's rates reflecting recovery of the Mobile Bay expansion project costs on a "rolled-in" basis have been in effect since September 1, 2001. The administrative law judge's initial decision is subject to review by the FERC. Power holds long-term transportation capacity on the Mobile Bay expansion project. If the FERC adopts the decision of the administrative law judge on the pricing of the Mobile Bay expansion project and also requires that the decision be implemented effective September 1, 2001, Power could be subject to surcharges of approximately $41 million, excluding interest, through December 31, 2003, in addition to increased costs going forward.

ENRON BANKRUPTCY

We have outstanding claims against Enron Corp. and various of its subsidiaries (collectively "Enron") related to Enron's bankruptcy filed in December 2001. In March 2002, we sold $100 million of our claims against Enron to a third party for $24.5 million. On December 23, 2003, Enron filed objections to these claims. Under the sales agreement, the purchaser of the claims may demand repayment of the purchase price, plus interest assessed at 7.5 percent per annum, for that portion of the claims still subject to objections 90 days following the initial objection.

ENVIRONMENTAL MATTERS

Continuing operations

Since 1989, Transco has had studies under way 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 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 U.S. Environmental Protection Agency (EPA) and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other programs 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 December 31, 2003, Transco had accrued liabilities of $28 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances.

We also accrue environmental remediation costs for our natural gas gathering and processing facilities, primarily related to soil and groundwater contamination. At December 31, 2003, we had accrued liabilities totaling approximately $11 million for these costs.

Actual costs incurred for these matters will depend on the actual number of contaminated sites identified, the amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors.

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.

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 December 31, 2003, we had accrued liabilities of approximately $9 million for such excess costs.

WILLIAMS ENERGY PARTNERS

As part of our June 17, 2003 sale of Williams Energy Partners (see Note 2), we indemnified the purchaser for:

(1) environmental cleanup costs resulting from certain conditions, primarily soil and groundwater contamination, at specified locations, to the extent such costs exceed a specified amount and

(2) currently unidentified environmental contamination relating to operations prior to April 2002 and identified prior to April 2008.

At December 31, 2003, we had accrued liabilities totaling approximately $9 million for these costs. In addition, we deferred a portion of the gain associated with our indemnifications, including environmental indemnifications, of the purchaser under the sales agreement. At December 31, 2003, we had a remaining deferred gain relating to this sale of approximately $96 million.

On July 2, 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from our pipelines, pipeline systems, and pipeline facilities used in the movement of oil or petroleum products, during the period from July 1, 1998 through July 2, 2001. In November 2001, we furnished our response. This matter has not become an enforcement proceeding. On March 11, 2004, the Department of Justice (DOJ) invited the new owner of the pipeline to enter into negotiations regarding alleged violations of the Clean Water Act and to sign a tolling agreement. No penalty has been assessed by the EPA; however, the DOJ stated in its letter that the maximum possible penalties were approximately $22 million for the alleged violations. It is anticipated that by providing additional clarification and through negotiations with the EPA and DOJ, that any proposed penalty will be reduced. We have indemnity obligations to the new owner related to this matter.

OTHER

At December 31, 2003, we had accrued environmental liabilities totaling approximately $17 million related to our:

- Alaska refining, retail and pipeline operations and the Canadian straddle plants currently classified as held for sale;
- potential indemnification obligations to purchasers of our former retail petroleum and refining operations;
- former propane marketing operations, petroleum products and natural gas pipelines, natural gas liquids fractionation;
- a discontinued petroleum refining facility; and
- exploration and production and mining operations.

These costs include (1) certain conditions at specified locations related primarily to soil and groundwater contamination and (2) any penalty assessed on Williams Refining & Marketing, LLC (Williams Refining) associated with noncompliance with EPA's benzene waste "NESHAP" regulations. In 2002, Williams Refining submitted to the EPA a self-disclosure letter indicating noncompliance with those regulations. This unintentional noncompliance had occurred due to a regulatory interpretation that resulted in under-counting the total annual benzene level at Williams Refinery's Memphis refinery. Also in 2002, the EPA conducted an all-media audit of the Memphis refinery. The EPA anticipates releasing a report of its audit findings in 2004. The EPA will likely assess a penalty on Williams Refining due to the benzene waste NESHAP issue, but the amount of any such penalty is not known. In connection with the sale of the Memphis refinery in March 2003, we indemnified the purchaser for any such penalty.

Certain of our subsidiaries have been identified as potentially responsible parties (PRP) 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.

OTHER LEGAL MATTERS

Royalty indemnifications

In connection with agreements 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 which the producers may be required to pay as a result of such settlements. Transco, through its agent, Power, 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 which have no carrying value. Producers have received 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.

As a result of these settlements, Transco has been sued by certain producers seeking indemnification from Transco. Transco is currently a defendant in one lawsuit in which a producer has asserted damages, including interest calculated through December 31, 2003, of approximately $10 million. On July 11, 2003, at the conclusion of the trial, the judge ruled in Transco's favor and subsequently entered a formal judgment. The plaintiff is seeking an appeal. On November 25, 2003, Transco and another producer settled a separate lawsuit in which the producer had asserted damages, including interest, of approximately $8 million.

Western gas resources

On October 24, 2003, we settled the claims by Western Gas Resources, Inc. and its subsidiary that our merger with Barrett Resources Corporation triggered a preferential right to purchase and a right to operate certain Barrett coal bed methane development properties in the Powder River Basin in Wyoming. As a result, terms in a long-term gathering agreement with Western were amended and a subsidiary of Western received operating rights to approximately one-half of the properties jointly owned with us.

Will Price (formerly Quinque)

On June 8, 2001, fourteen of our entities were named as defendants in a nationwide class action lawsuit which had been pending against other defendants, generally pipeline and gathering companies, for more than one year. The plaintiffs allege that the defendants, including us, 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. After the court denied class action certification and while motions to dismiss for lack of personal jurisdiction were pending, the court granted the plaintiffs' motion to amend their petition on July 29, 2003. The fourth amended petition, which was filed on July 29, 2003, deletes all of our defendants except two Midstream subsidiaries. All defendants intend to continue their opposition to class certification.

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 sale of Kern River and Texas Gas, 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. The amounts accrued for these indemnifications are insignificant. Grynberg has 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. On April 9, 1999, the DOJ announced that it was declining to intervene in any of the Grynberg qui tam cases, including the action filed in federal court in Colorado against us. On October 21, 1999, the Panel on Multi-District Litigation transferred all of the Grynberg qui tam cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. Grynberg's measurement claims remain pending against us and the other defendants; the court previously dismissed Grynberg's royalty valuation claims.

On August 6, 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 Williams Production RMT Company with a complaint in the state court in Denver, Colorado. The complaint alleges that the defendants have used mismeasurement techniques that distort the BTU 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 defendants inappropriately took deductions from the gross value of their natural gas and made other royalty valuation errors. Theories for relief include breach of contract, breach of implied covenant of good faith and fair dealing, anticipatory repudiation, declaratory relief, equitable accounting, civil theft, deceptive trade practices, negligent misrepresentation, deceit based on fraud, conversion, breach of fiduciary duty, and violations of the state racketeering statute. 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 $1.4 million dollars. Our motion to stay the proceedings in this case based on the pendency of the False Claims Act litigation discussed in the preceding paragraph was granted on January 15, 2003.

Securities class actions

Numerous shareholder class action suits have been filed against us in the United States District Court for the Northern District of Oklahoma. The majority of the suits allege that we and co-defendants, WilTel and certain corporate officers, have acted jointly and separately to inflate the stock price of both companies. Other suits allege similar causes of action related to a public offering in early January 2002, known as the FELINE PACS offering. These cases were filed against us, certain corporate officers, all members of our Board of Directors and all of the offerings' underwriters. These cases have all been consolidated and an order has been issued requiring separate amended consolidated complaints by our equity holders and WilTel equity holders. The amended complaint of the WilTel securities holders was filed on September 27, 2002, and the amended complaint of our securities holders was filed on October 7, 2002. This amendment added numerous claims related to Power. In addition, four class action complaints have been filed against us, the members of our Board of Directors and members of our Benefits and Investment Committees under the Employee Retirement Income Security Act (ERISA) by participants in our 401(k) plan. A motion to consolidate these suits has been approved. On July 14, 2003, the Court dismissed us and our Board from the ERISA suits, but not the members of the Benefits and Investment Committees to whom we might have an indemnity obligation. The Department of Labor is also independently investigating our employee benefit plans. On December 15, 2003, the court substantially denied the defendants' motion to dismiss in the shareholder suits. Derivative shareholder suits have been filed in state court in Oklahoma, all based on similar allegations. On August 1, 2002, a motion to consolidate and a motion to stay these Oklahoma suits pending action by the federal court in the shareholder suits was approved.

Oklahoma securities investigation

On April 26, 2002, the Oklahoma Department of Securities issued an order initiating an investigation of us and WilTel regarding issues associated with the spin-off of WilTel and regarding the WilTel bankruptcy. We have no pending inquiries in this investigation, but are committed to cooperate fully in the investigation.

Shell offshore litigation

On November 30, 2001, Shell Offshore, Inc. filed a complaint at the FERC against Williams Gas Processing -- Gulf Coast Company, L.P. (WGP), Williams Gulf Coast Gathering Company (WGCGC), Williams Field Services Company (WFS) and Transco, alleging concerted actions by the affiliates frustrating the FERC's regulation of Transco. The alleged actions are related to offers of gathering service by WFS and its subsidiaries on the deregulated North Padre Island offshore gathering system. On September 5, 2002, the FERC issued an order reasserting jurisdiction over that portion of the North Padre Island facilities previously transferred to WFS. The FERC also determined an unbundled gathering rate for service on these facilities which is to be collected by Transco. Transco, WGP, WGCGC and WFS believe their actions were reasonable and lawful and each have filed petitions for review of the FERC's orders with the U.S. Court of Appeals for the District of Columbia.

TAPS Quality Bank

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. Primary issues being litigated include the appropriate valuation of the naphtha, heavy distillate, vacuum gas oil and residual product cuts within the TAPS Quality Bank as well as the appropriate retroactive effects of the determinations. WAPI's interest in these proceedings is material as the matter involves claims by crude producers and the State of Alaska for retroactive payments plus interest of up to $180 million. Because of the complexity of the issues involved, however, the outcome cannot be predicted with certainty nor can the likely result be quantified. Certain periodic discussions have been held and continue among some of the litigants. Because of the number of parties involved and the diversity of positions, no comprehensive terms have been identified that could be considered probable to achieve final settlement among all parties. The FERC and RCA presiding administrative law judges are expected to render their joint and/or individual initial decision(s) sometime during the second quarter of 2004.

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. At December 31, 2003, 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 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 coverage, recovery from customers or other indemnification arrangements, will not have a materially adverse effect upon our future financial position.

COMMITMENTS

Power has entered into certain contracts giving it the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are currently in operation throughout the continental United States. At December 31, 2003, Power's estimated committed payments under these contracts range from approximately $391 million to $422 million annually through 2017 and decline over the remaining five years to $57 million in 2022. Total committed payments under these contracts over the next 19 years are approximately $6.7 billion.

NOTE 17. RELATED PARTY TRANSACTIONS

LEHMAN BROTHERS HOLDINGS, INC.

Lehman Brothers Inc. is a related party as a result of a director that serves on our Board of Directors and Lehman Brothers Holdings, Inc.'s Board of Directors. In third-quarter 2002, RMT, a wholly owned subsidiary, entered into a $900 million short-term Credit Agreement dated July 31, 2002, with certain lenders including a subsidiary of Lehman Brothers Inc. This debt obligation was paid in second-quarter 2003 (see Note 11). Included in interest accrued on the Consolidated Statement of Operations for 2003 and 2002, are $199.4 million and $154.1 million, respectively, of interest expense, including amortization of deferred set up fees related to the RMT note. As of December 31, 2003, the amount due to Lehman Brothers, Inc., related primarily to advisory fees was $1.8 million. At December 31, 2002, the amount payable related to the RMT note and related interest was approximately $1 billion. In addition, we paid $37.2 million, $39.6 million and $27 million to Lehman Brothers Inc. in 2003, 2002, and 2001, respectively, primarily for underwriting fees related to debt and equity issuances as well as strategic advisory and restructuring success fees.

AMERICAN ELECTRIC POWER COMPANY, INC.

American Electric Power Company, Inc. (AEP) is a related party as a result of a director that serves on both our Board of Directors and AEP's Board of Directors. Our Power segment engaged in forward and physical power and gas trading activities with AEP. Net revenues from AEP were $264.6 million in 2002. There were no trading activities with AEP in 2003. Amounts due to AEP were $106.4 million as of December 31, 2002. Amounts receivable from AEP were $215.1 million as of December 31, 2002. During 2002, AEP disputed a settlement amount related to the liquidation of a trading position with Power. Arbitration was initiated and in 2003 AEP paid Power $90 million to resolve the dispute.

EXXONMOBIL CORPORATION

ExxonMobil Corporation is a related party as a result of a director that serves on both our Board of Directors and ExxonMobil Corporation's Board of Directors. Transactions with ExxonMobil Corporation result primarily from the purchase and sale of crude oil, refined products and natural gas liquids in support of crude oil, refined products and natural gas liquids trading activities and strategies as well as revenues generated from gathering and processing activities. Aggregate revenues from this customer, including those reported on a net basis in 2002 and 2001, were $121.8 million, $217.6 million and $38.9 million in 2003, 2002 and 2001, respectively. Aggregate purchases from this customer were $30.4 million, $15.6 million and $6.4 million in 2003, 2002 and 2001, respectively. Amounts due from ExxonMobil were $40.0 million and $22.1 million as of December 31, 2003 and 2002, respectively. Amounts due to ExxonMobil were $8.7 million and $66.9 million as of December 31, 2003 and 2002, respectively.

NOTE 18. ACCUMULATED OTHER COMPREHENSIVE INCOME

The table below presents changes in the components of accumulated other comprehensive income.

	INCOME (LOSS)				
	CASH FLOW HEDGES	UNREALIZED APPRECIATION (DEPRECIATION) ON SECURITIES	FOREIGN CURRENCY TRANSLATION	MINIMUM PENSION LIABILITY	TOTAL
			(MILLIONS)		
Balance at December 31, 2000	$ --	$ 72.7	$ (44.5)	$ --	$ 28.2
2001 CHANGE:					
Cumulative effect of change in accounting for derivative instruments (net of $58.9 million income tax)	(94.5)	--	--	--	(94.5)
Pre-income tax amount	896.8	(69.7)	(39.9)	(3.6)	783.6
Income tax benefit (provision)	(343.3)	27.5	-	1.4	(314.4)
Minority interest in other comprehensive loss	--	5.4	2.8	--	8.2
Net realized gains in net income (net of $.1 income tax and $1.8 minority interest)	--	1.5	-	--	1.5
Net reclassification into earnings of derivative instrument-gains (net of a $55.7 million income tax)	(88.8)	--	-	--	(88.8)
	370.2	(35.3)	(37.1)	(2.2)	295.6
Adjustment due to spinoff of WilTel	--	(36.5)	57.8	--	21.3
Balance at December 31, 2001	370.2	.9	(23.8)	(2.2)	345.1
2002 CHANGE:					
Pre-income tax amount	(170.7)	5.3	(.1)	(27.3)	(192.8)
Income tax benefit (provision)	65.0	(1.9)	--	10.4	73.5
Minority interest in other comprehensive loss	.4	--	--	--	.4
Net realized loss in net loss (net of $.7 income tax)	--	1.2	--	--	1.2
Net reclassification into earnings of derivative instrument gains (net of a $119.2 million income tax)	(193.6)	--	--	--	(193.6)
	(298.9)	4.6	(.1)	(16.9)	(311.3)
Balance at December 31, 2002	71.3	5.5	(23.9)	(19.1)	33.8
2003 CHANGE:					
Pre-income tax amount	(408.8)	2.6	77.0	18.2	(311.0)
Income tax benefit (provision)	156.3	(1.0)		(6.9)	148.4
Net reclassification into earnings of derivative instrument losses (net of a $9.7 million income tax benefit)	15.6	--	--	--	15.6
Realized gains on securities reclassified into earnings (net of $5.3 income tax)	--	(9.0)	--	--	(9.0)
Reclassification into earnings due to sale of Bio-energy facilities	--	--	--	1.2	1.2
	(236.9)	(7.4)	77.0	12.5	(154.8)
Balance at December 31, 2003	$ (165.6)	$ (1.9)	$ 53.1	$ (6.6)	$ (121.0)

The 2001 adjustment due to the spin-off of WilTel includes unrealized appreciation (depreciation) on securities and foreign currency translation balances that relate to WilTel (see Note 2).

AVAILABLE FOR SALE SECURITIES

At December 31, 2003, we held U.S. Treasury securities with a fair value of $381.3 million. These securities mature within three to six months. Gross unrealized losses of $3 million on these securities are included in Accumulated Other Comprehensive Income at December 31, 2003.

During 2003 we received proceeds totaling $370.5 million from the sale and maturity of available for sale securities. We realized gross gains and losses of $14.4 million and $0.1 million, respectively, from these transactions.

At December 31, 2002, we held marketable equity securities for which gross unrealized gains of $8.7 million were included in Accumulated Other Comprehensive Income.

NOTE 19. SEGMENT DISCLOSURES

SEGMENTS AND RECLASSIFICATION OF OPERATIONS

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. The segment formerly named Energy Marketing & Trading is now named Power. The Petroleum Services segment is now reported within Other as the result of a significant portion of its assets being reflected as discontinued operations. Segment amounts have been restated to reflect this change. Other primarily consists of corporate operations and certain continuing operations previously reported within the International and Petroleum Services segments.

Segment amounts for 2002 and 2001 reflect the reclassification of the Petroleum Services segment to Other.

Since May 1995, an entity within our Midstream segment has operated production area facilities owned by entities within our Gas Pipeline segment. These regulated gas gathering assets have been operated pursuant to the terms of an operating agreement. Effective June 1, 2004, and due in part to FERC Order 2004, the operating agreement was terminated and management and decision-making control transferred to the Gas Pipeline segment. Consequently, the results of operations were similarly reclassified. All prior periods reflect these classifications.

Effective September 21, 2004, and due in large part to FERC Order 2004, management and decision-making control of our equity method investment in the Aux Sable gas processing plant and related business was transferred from our Midstream segment to our Power segment. Consequently, the results of operations were similarly reclassified. All prior periods reflect these classifications.

SEGMENTS -- PERFORMANCE MEASUREMENT

We currently evaluate performance based on segment profit (loss) from operations, which includes revenues from external and internal customers, operating costs and expenses, depreciation, depletion and amortization, equity earnings (losses) and income (loss) from investments including gains/losses on impairments related to investments accounted for under the equity method. The accounting policies of the segments are the same as those described in Note 1, Summary of significant accounting policies. Intersegment sales are generally accounted for at current market prices as if the sales were to unaffiliated third parties.

Power has entered into intercompany interest rate swaps with the corporate parent, the effect of which is included in Power's segment revenues and segment profit (loss) as shown in the reconciliation within the following tables. The results of interest rate swaps with external counterparties are shown as interest rate swap income (loss) in the Consolidated Statement of Operations below operating income.

The majority of energy commodity hedging by certain of our business units is done through intercompany derivatives with Power which, in turn, enters into offsetting derivative contracts with unrelated third parties. Power bears the counterparty performance risks associated with unrelated third parties.

The following geographic area data includes revenues from external customers based on product shipment origin and long-lived assets based upon physical location.

	UNITED STATES	OTHER	TOTAL
		(MILLIONS)	
Revenues from external customers:			
2003	$ 15,749.5	$ 895.2	$ 16,644.7
2002	3,167.3	226.6	3,393.9
2001	4,738.4	161.1	4,899.5
Long-lived assets:			
2003	$ 11,982.0	$ 776.9	$ 12,758.9
2002	11,996.7	772.2	12,768.9

The increase in revenues in 2003 is due primarily to the adoption of EITF 02-3 in 2003, which requires that revenues and costs of sale from non-derivative contracts and certain physically settled derivative contracts be reported on a gross basis. Prior to the adoption, these revenues were presented net of costs. As permitted by EITF 02-3, prior year amounts have not been restated. Results for 2003 include approximately $117 million of revenue related to the correction of the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001.

Long-lived assets are comprised of property, plant and equipment, goodwill and other intangible assets.

	POWER	GAS PIPELINE	EXPLORATION & PRODUCTION	MIDSTREAM GAS & LIQUIDS	OTHER	ELIMINATIONS	TOTAL
				(MILLIONS)			
2003							
Segment revenues:							
External	$ 12,570.5	$ 1,344.3	$ (36.3)	$ 2,733.9	$ 32.3	$ --	$ 16,644.7
Internal	622.1	24.0	816.0	44.6	39.7	(1,546.4)	--
Total segment revenues	13,192.6	1,368.3	779.7	2,778.5	72.0	(1,546.4)	16,644.7
Less intercompany interest rate swap loss	(2.9)	--	--	--	--	2.9	--
Total revenues	$ 13,195.5	$ 1,368.3	$ 779.7	$ 2,778.5	$ 72.0	$(1,549.3)	$ 16,644.7
Segment profit (loss)	$ 135.1	$ 555.5	$ 401.4	$ 328.7	$ (50.5)	$ --	$ 1,370.2
Less:							
Equity earnings (losses)	(4.9)	15.8	8.9	(.8)	1.3	--	20.3
Income (loss) from investments	(2.4)	0.1	--	20.1	(43.1)	--	(25.3)
Intercompany interest rate swap loss	(2.9)	--	--	--	--	--	(2.9)
Segment operating income (loss)	$ 145.3	$ 539.6	$ 392.5	$ 309.4	$ (8.7)	$ --	1,378.1
General corporate expenses							(87.0)
Consolidated operating income							$ 1,291.1
Other financial information:							
Additions to long-lived assets	$ 1.0	$ 517.4	$ 241.5	$ 255.0	$ 2.5	$ --	$ 1,017.4
Depreciation, depletion & amortization	$ 31.5	$ 274.6	$ 173.9	$ 157.7	$ 19.7	$ --	$ 657.4
2002							
Segment revenues:							
External	$ 909.6	$ 1,244.1	$ 62.6	$ 1,110.7	$ 66.9	$ --	$ 3,393.9
Internal	(994.8)*	57.1	797.8	32.4	57.2	50.3	--
Total segment revenues	(85.2)	1,301.2	860.4	1,143.1	124.1	50.3	3,393.9
Less intercompany interest rate swap loss	(141.4)	--	--	--	--	141.4	--
Total revenues	$ 56.2	$ 1,301.2	$ 860.4	$ 1,143.1	$ 124.1	$ (91.1)	$ 3,393.9
Segment profit (loss)	$ (626.2)	$ 535.8	$ 508.6	$ 196.9	$ 14.1	$ --	$ 629.2
Less:							
Equity earnings (losses)	(11.1)	88.4	3.7	19.0	(27.0)	--	73.0
Income (loss) from investments	(2.0)	(13.9)	--	--	58.0	--	42.1
Intercompany interest rate swap loss	(141.4)	--	--	--	--	--	(141.4)
Segment operating income (loss)	$ (471.7)	$ 461.3	$ 504.9	$ 177.9	$ (16.9)	$ --	655.5
General corporate expenses							(142.8)
Consolidated operating income							$ 512.7
Other financial information:							
Additions to long-lived assets	$ 135.8	$ 705.0	$ 382.8	$ 616.4	$ 51.7	$ --	$ 1,891.7
Depreciation, depletion & amortization	$ 33.1	$ 253.0	$ 184.6	$ 149.9	$ 28.2	$ --	$ 648.8
2001							
Segment revenues:							
External	$ 2,249.6	$ 1,204.5	$ 121.6	$ 1,075.5	$ 248.3	$ --	$ 4,899.5
Internal	(544.0)*	38.6	482.3	79.7	71.0	(127.6)	--
Total revenues and segment revenues	$ 1,705.6	$ 1,243.1	$ 603.9	$ 1,155.2	$ 319.3	$ (127.6)	$ 4,899.5
Segment profit	$ 1,265.1	$ 463.8	$ 231.8	$ 173.9	$ 37.5	$ --	$ 2,172.1

Less:							
Equity earnings (losses).........	(6.2)	46.3	14.6	(9.1)	(22.9)	--	22.7
Income (loss) from investments...	(23.3)	27.5	--	--	--	--	4.2
Segment operating income...........	$ 1,294.6	$ 390.0	$ 217.2	$ 183.0	$ 60.4	$ --	2,145.2
General corporate expenses.........							(124.3)
Consolidated operating income......							$ 2,020.9
Other financial information:							
Additions to long-lived assets.....	$ 209.2	$ 559.2	$ 3,561.1	$ 560.7	$ 53.5	$ --	$ 4,943.7
Depreciation, depletion & amortization.....................	$ 20.0	$ 247.8	$ 97.1	$ 123.9	$ 26.6	$ --	$ 515.4

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* Prior to January 1, 2003, Power intercompany cost of sales, which are netted in revenues consistent with fair-value accounting, exceed intercompany revenues. Beginning January 1, 2003, Power intercompany cost of sales are no longer netted in revenues due to the adoption of EITF Issue No. 02-3 (see Note 1). Segment revenues and profit for Power include net realized and unrealized mark-to market gains of $401 million from derivative contracts accounted for on a fair value basis for the year ended December 31, 2003.

	TOTAL ASSETS		EQUITY METHOD INVESTMENTS	
	DECEMBER 31, 2003	DECEMBER 31, 2002	DECEMBER 31, 2003	DECEMBER 31, 2002
	(MILLIONS)			
Power(1)	$ 8,732.9	$ 12,587.7	$ 42.8	$ 54.8
Gas Pipeline	7,314.3	7,290.2	774.4	778.4
Exploration & Production	5,347.4	5,595.1	41.5	35.8
Midstream Gas & Liquids	3,990.3	3,922.0	289.9	227.2
Other	6,928.7	7,664.3	85.1	93.9
Eliminations	(6,078.2)	(6,636.9)	--	--
	26,235.4	30,422.4	1,233.7	1,190.1
Net assets of discontinued operations	786.4	4,566.1	--	--
Total assets	$ 27,021.8	$ 34,988.5	$ 1,233.7	$ 1,190.1

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(1) The decrease in Power's total assets is largely due to the decrease in energy risk management and trading assets as a result of the adoption of EITF 02-3 (see Note 1).

20. EVENTS (UNAUDITED) SUBSEQUENT TO THE DATE OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM'S REPORT

NOTES PAYABLE AND LONG-TERM DEBT

In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of a specified series of our outstanding notes and debentures. As of the June 8, 2004, tender offer expiration date, we had accepted for purchase tenders of notes and debentures with an aggregate principal amount of approximately $1.17 billion. In May 2004, we also repurchased approximately $255 million of various notes with maturity dates ranging from 2006 to 2011. In conjunction with these tendered notes and debentures and related consents, and early retirements, we paid premiums of approximately $79 million.

Revolving credit and letter of credit facilities

In April 2004, we entered into two unsecured bank revolving credit facilities totaling $500 million. These facilities provide for both borrowings and issuing letters of credit, but are used primarily for issuing letters of credit. We are required to pay to the bank fixed fees at a weighted-average rate of 3.64 percent on the total committed amount of the facilities. In addition, we pay interest on any borrowings at a fluctuating rate comprised of either a base rate or LIBOR. We were able to obtain the unsecured credit facilities because the funding bank syndicated its associated credit risk into the institutional investor market via a 144A offering, which allows for the resale of certain restricted securities to qualified institutional buyers. Upon the occurrence of certain credit events, letters of credit outstanding under the agreement become cash collateralized creating a borrowing under the facilities. Concurrently the bank can deliver the facilities to the institutional investors, whereby the investors replace the bank as lender under the facilities. Upon such occurrence, we will pay:

- a fixed facility fee at a weighted average rate of 3.19 percent to the investors,
- interest on borrowings under the $400 million facility equal to a fixed rate of 3.57 percent, and
- interest on borrowings under the $100 million facility at a fluctuating LIBOR interest rate.

To facilitate the syndication of these facilities, the bank established trusts funded by the institutional investors. The assets of the trusts serve as collateral to reimburse the bank for our borrowings in the event the facilities are delivered to the investors. Thus, we have no asset securitization or collateral requirements under the new facilities. During second-quarter 2004, use of these new facilities replaced existing facilities and released approximately $500 million of restricted cash, restricted investments and margin deposits which secured our previous $800 million revolving and letter of credit facility. Significant covenants under these new facilities include the following:

- limitations on certain payments, including a limitation on the payment of quarterly dividends to no greater than $.05 per common share;
- limitations on asset sales;
- limitations on the use of proceeds from permitted asset sales;
- limitations on transactions with affiliates; and
- limitations on the incurrence of additional indebtedness and issuance of disqualified stock, unless the fixed charge coverage ratio for our most recently ended four full fiscal quarters is at least 2 to 1, determined on a proforma basis.

On May 3, 2004, we entered into a new three-year, $1 billion secured revolving credit facility which is available for borrowings and letters of credit. In August, 2004, we expanded the credit facility by an additional $275 million. Northwest Pipeline Corporation (Northwest) and Transcontinental Gas Pipeline Corporation (Transco) have access to $400 million each under the facility. The new facility is secured by certain Midstream assets, including substantially all of our southwest Wyoming, Wamsutter, San Juan Conventional, Manzanares and Torre Alta systems. Additionally, the facility is guaranteed by WGP. Interest is calculated based on a choice of two methods: a fluctuating rate equal to the facilitating bank's base rate plus an applicable margin or a periodic fixed rate equal to LIBOR plus an applicable margin. We are also required to pay a commitment fee based on the unused portion of the facility, currently .375 percent. The applicable margins and commitment fee are based on the relevant borrower's senior unsecured long-term debt ratings. Significant financial covenants under the credit agreement include:

- ratio of debt to capitalization no greater than (i) 75 percent for the period June 30, 2004 through December 31, 2004, (ii) 70 percent for the period after December 31, 2004 through December 31, 2005, and (iii) 65 percent for the remaining term of the agreement;
- ratio of debt to capitalization no greater than 55 percent for Northwest and Transco; and
- ratio of EBITDA to Interest, on a rolling four quarter basis (or, in the first year, building up to a rolling four quarter basis), no less than (i) 1.5 for the periods ending September 30, 2004 through March 31, 2005, (ii) 2.0 for any period after March 31, 2005 through December 31, 2005, and (iii) 2.5 for the remaining term of the agreement.

Upon entering into the new $1 billion secured revolving credit facility on May 3, 2004, we terminated the $800 million revolving and letter of credit facility which we entered into in June 2003.

In August 2004, we made cash tender offers and consent solicitations for all of our 8.625 percent senior notes due 2010. Approximately $792.8 million, or approximately 99 percent, aggregate principal amount of notes were accepted for purchase. In conjunction with this purchase, we paid premiums of approximately $135 million.

On September 17, 2004, we initiated an offer to exchange up to 43.9 million FELINE PACS units for one share of our common stock plus $1.47 in cash for each unit. The offer expired October 18, 2004 and resulted in approximately 33.1 million of the 44 million issued and outstanding units being tendered and accepted for exchange. The exchange offer reduced our overall debt by approximately $827 million and increased our common stock outstanding by 33.1 million shares. The effect of the exchange, including a pre-tax charge for related expenses of approximately $25 million, will be reflected in the fourth quarter.

ENVIRONMENTAL MATTERS

As part of our June 17, 2003 sale of Williams Energy Partners (see Note 2), we indemnified the purchaser for:

(1) environmental cleanup costs resulting from certain conditions, primarily soil and groundwater contamination, at specified locations, to the extent such costs exceed a specified amount and

(2) currently unidentified environmental contamination relating to operations prior to April 2002 and identified prior to April 2008.

On May 26, 2004, the parties reached an agreement for buyout of certain indemnities in the form of a structured cash settlement totaling $117.5 million. Yearly payments will be made through 2007. The agreement releases Williams from all environmental indemnity obligations under the June 2003 Sale of Williams Energy Partners and two related agreements. Williams is now indemnified by the purchaser for third party environmental claims made against Williams for claims covered under the June 2003 purchase and sale agreement (PSA) and related agreements as well as all environmental occurrences before the closing date of the PSA. The agreement also transferred most third party litigation matters related to Williams Energy Partners' assets to the purchaser.

ASSET SALES

On July 28, 2004, we closed the sale of the Canadian straddle plants for approximately $544 million in U.S. funds, including amounts paid to our subsidiaries for amounts previously due from the straddle plants. We expect to recognize a pre-tax gain of approximately $190 million on the sale in third-quarter 2004.

OTHER LEGAL MATTERS

As discussed in Note 16, 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. Primary issues being litigated include the appropriate valuation of the naptha, heavy distillate, vacuum gas oil and residual product cuts within the TAPS Quality Bank as well as the appropriate retroactive effects of the determinations.

The FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions during the third quarter of 2004. The initial decisions set forth methodologies for determining the valuations of the product cuts under review and also approved the retroactive application of the approved methodologies for the heavy distillate and residual product cuts. Based on our computation and assessment of ultimate ruling terms that would be considered probable, we recorded an accrual of approximately $134 million in the third quarter of 2004. Because the application of certain aspects of the initial decisions are subject to interpretation, we have calculated the reasonably possible impact of the decisions, if fully adopted by the FERC and RCA, to result in additional exposure to us of approximately $32 million more than we have accrued at September 30, 2004. We will be filing a brief on exceptions to the initial decisions to both the FERC and RCA on November 16, 2004, and reply briefs are due on February 1, 2005. Decisions from the Commissions will then be issued likely before the end of 2005. It is unlikely that we will be required to make any payments with respect to this matter until sometime after the Commission decisions.

Winterthur International Insurance Company (Winterthur) issued policies to Gulf Liquids providing financial assurance related to construction contracts among Gulf Liquids, Gulsby Engineering, Inc. and Gulsby-Bay. After disputes arose regarding obligations under the construction contracts, Winterthur disputed coverage resulting in arbitration between Winterthur and Gulf Liquids. In July 2004, the arbitration panel awarded Gulf Liquids $93.6 million, offset by $18 million previously paid to Gulf Liquids, plus interest of $7.7 million, for a total award to Gulf Liquids of approximately $83.3 million. Winterthur has filed a Petition to Vacate the Arbitration Award in the New York State court. On November 1, 2004, Winterthur remitted approximately $85 million to us in the settlement of certain disputes regarding obligations under construction contracts. As a result of the payment, we will recognize pre-tax income of approximately $95 to $100 million within Income from discontinued operations in the fourth quarter.

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA
(UNAUDITED)

Summarized quarterly financial data are as follows (millions, except per-share amounts). Certain amounts have been restated or reclassified as described in Note 1 of Notes to Consolidated Financial Statements.

	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
2003				
Revenues	$ 4,776.1	$ 3,612.3	$ 4,743.4	$ 3,512.9
Costs and operating expenses	4,423.6	3,024.8	4,387.6	3,153.7
Income (loss) from continuing operations	(43.1)	113.7	20.0	(62.4)
Net income (loss)	(814.5)	269.7	106.3	(53.7)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	(.10)	.18	.04	(.12)
Net income (loss)	(1.59)	.48	.21	(.10)
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	(.10)	.17	.04	(.12)
Net income (loss)	(1.59)	.46	.20	(.10)
2002				
Revenues	$ 1,140.1	$ 596.1	$ 643.8	$ 1,013.9
Costs and operating expenses	468.5	473.5	466.3	526.0
Income (loss) from continuing operations	42.4	(338.9)	(179.6)	(121.0)
Net income (loss)	107.7	(349.1)	(294.1)	(219.2)
Basic and diluted earnings (loss) per common share:				
Loss from continuing operations	(.06)	(.66)	(.36)	(.25)
Net income (loss)	.07	(.68)	(.58)	(.44)

The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to changes in the average number of common shares outstanding and rounding.

Net loss for fourth-quarter 2003 includes the following items which are pre-tax:

- $45.0 million impairment of goodwill at Power (see Note 4),

- $44.1 million impairment of the Hazelton generation facility at Power (see Note 4),

- $33.3 million California rate refund and other accrual adjustments at Power (see Note 4),

- $19.9 million in unrealized gains on certain derivative contracts that had previously not been recognized in 2003, including approximately $10 million of revenue related to the accounting treatment applied to certain derivative contracts terminated in prior periods at Power (see Note 1),

- $16.2 million gain on sale of the wholesale propane business at Midstream (see Note 4),

- $66.8 million of costs for the early retirement of debt (see Note 10),

- $31.5 million income from discontinued operations (see Note 2), and

- $18.9 million loss from discontinued operations for impairments and net gains on sales (see Note 2).

Net income for third-quarter 2003 includes the following items which are pre-tax:

- $13.0 million gain on sale of a full requirements contract at Power (see Note 4),
- $126.8 million positive valuation adjustment on a terminated derivative contract at Power,
- $13.5 million gain on sale of marketable equity securities at Power (see Note 3),
- $11.0 million gain on sale of equity interest in West Texas LPG Pipeline, L.P. investment at Midstream (see Note 3),
- $16.7 million income from discontinued operations (see Note 2), and
- $72.3 million gain from discontinued operations for impairments and net gains on sales (see Note 2).

Net income for second-quarter 2003 includes the following items which are pre-tax:

- $20 million Commodity Futures Trading Commission settlement at Power (see Note 4),
- $175 million gain on sale of a full requirements contract at Power (see Note 4),
- $25.5 million write-off of software development costs at Gas Pipelines (see Note 4),
- $80.7 million correction, attributable to prior periods relating to the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001 at Power (see Note 1),
- $12.4 million of revenue attributable to prior periods relating to the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001 and recorded prior to the $80.7 million correction in second-quarter at Power (see Note 1),
- $94.1 million gain on the sale of certain natural gas properties at Exploration & Production (see Note 4),
- $42.4 million impairment of an investment in equity and debt securities of Longhorn Partners Pipeline L.P. at Other (see Note 4),
- $14.5 million in accelerated amortization of costs related to the termination of the revolving credit agreement,
- $13.5 million impairment of cost based investment in ReserveCo, a company holding phosphate reserves (see Note 3),
- $22.6 million income from discontinued operations (see Note 2), and
- $232.9 million gain from discontinued operations for impairments and net gains on sales (see Note 2).

Net loss for first-quarter 2003 includes the following items which are pre-tax:

- $13.7 million of revenue attributable to prior periods relating to the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001 and recorded prior to the $80.7 million correction in second-quarter at Power (see Note 1),
- $12.0 million impairment of a cost based investment in Algar Telecom S.A. at Other (see Note 3),
- $761.3 million cumulative effect of change in accounting principles related to the adoption of EITF Issue No. 02-3 and SFAS No. 143 (see Note 1),
- $96.8 million income from discontinued operations (see Note 2), and
- $117.3 million loss from discontinued operations for impairments and net losses on sales (see Note 2).

Net loss for fourth-quarter 2002 includes the following items which are pre-tax:

- $85.0 million net revenue impact related to the settlement and valuation of Power contracts with the State of California,
- $44.7 million impairment of the Worthington generation facility at Power (see Note 4),
- $50.8 million loss accruals and impairments of other power related assets at Power (see Note 4),
- $17.0 million charge associated with a FERC settlement at Gas Pipeline (see Note 16),
- $78.2 million impairment of Canadian assets at Midstream (see Note 4),
- $89.4 million income from discontinued operations (see Note 2), and
- $227.2 million loss from discontinued operations for impairments and net losses on sales (see Note 2).

Net loss for third-quarter 2002 includes the following items which are pre-tax:

- $10.5 million loss accruals related to commitments for certain assets previously planned to be used in power projects at Power (see Note 4),
- $11.6 million net write-down pursuant to the sale of our equity interest in a Canadian and U.S. gas pipeline, at Gas Pipeline (see Note 3),
- $143.9 million gain related to the sale of certain natural gas production properties at Exploration & Production (see Note 4),
- $58.5 million gain on sale of our investment in a Lithuanian oil refinery, pipeline and terminal complex, included at Other (see Note 3),
- $22.9 million charge, included in continuing operations, related to estimated losses from an assessment of the recoverability of WilTel related receivables (see Note 2),
- $57.2 million income from discontinued operations (see Note 2), and
- $231.4 million loss from discontinued operations for impairments and net losses on sales (see Note 2).

Net loss for second-quarter 2002 includes the following items which are pre-tax:

- $57.5 million impairment of goodwill at Power due to deteriorating market conditions in the merchant energy sector (see Note 4),

- $58.9 million of loss accruals related to commitments for certain assets previously planned to be used in power projects and write-offs associated with a terminated power plant project at Power (see Note 4),

- $31.8 million impairment of other power related assets at Power (see Note 4),

- $12.3 million write-down of Gas Pipeline's investment in a pipeline project which was cancelled in 2002 (see Note 3),

- $27.4 million benefit which reflects a contractual construction completion fee received by one of our equity affiliates at Gas Pipeline whose operations are accounted for under the equity method of accounting (see Note 3),

- $15.0 million charge, included in continuing operations, related to estimated losses from an assessment of the recoverability of WilTel related receivables (see Note 2),

- $28.8 million of expense was recorded for our early retirement option,

- $56.9 million income from discontinued operations (see Note 2), and

- $71.1 million loss from discontinued operations for impairments and net losses on sales (see Note 2).

Net income for first-quarter 2002 includes the following items which are pre-tax:

- $232.0 million charge, included in continuing operations, related to estimated losses from an assessment of the recoverability of WilTel related receivables (see Note 2),

- $144.5 million income from discontinued operations (see Note 2), and

- $38.1 million loss from discontinued operations for impairments and net losses on sales (see Note 2).

THE WILLIAMS COMPANIES, INC.

SUPPLEMENTAL OIL AND GAS DISCLOSURES
(UNAUDITED)

The following information pertains to our oil and gas producing activities and is presented in accordance with SFAS No. 69, "Disclosures About Oil and Gas Producing Activities." The information is required to be disclosed by geographic region. We have significant oil and gas producing activities primarily in the Rocky Mountain and Mid-continent areas of the United States. Additionally, we have oil and gas producing activities in Argentina and Venezuela. However, proved reserves and revenues related to these activities are approximately 7.3 percent and 4.2 percent, respectively, of our total international and domestic oil and gas producing activities. The following information relates only to the oil and gas activities in the United States and includes the activities of those properties that qualified for reporting as discontinued operations in the Consolidated Statement of Operations.

CAPITALIZED COSTS

	AS OF DECEMBER 31, 2003	AS OF DECEMBER 31, 2002
	(MILLIONS)	
Proved properties	$ 2,464.4	$ 2,544.8
Unproved properties	682.5	784.5
	3,146.9	3,329.3
Accumulated depreciation, depletion, and amortization, and valuation provisions	(511.1)	(417.7)
Net capitalized costs	$ 2,635.8	$ 2,911.6

- Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. These amounts for 2003 and 2002 do not include approximately $1 billion of goodwill related to the purchase of Barrett Resources Corp. (Barrett) in 2001.

- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves; development wells and related equipment and facilities (including uncompleted development well costs); successful exploratory wells and related equipment and facilities (and uncompleted exploratory well costs) and support equipment.

- Unproved properties consist primarily of acreage related to probable reserves acquired through the Barrett acquisition in addition to a small portion of unproved exploratory acreage.

COSTS INCURRED

	FOR THE YEAR ENDED DECEMBER 31, 2003	2002	2001
		(MILLIONS)	
Acquisition	$ 11.3	$ --	$ 2,557.0
Exploration	7.1	15.5	35.6
Development	186.8	374.3	198.9
	$ 205.2	$ 389.8	$ 2,791.5

- Costs incurred include capitalized and expensed items.

- Acquisition costs include costs incurred to purchase, lease, or otherwise acquire a property, the majority of the 2001 costs relates to the Barrett acquisition during 2001.

- Exploration costs include the costs of geological and geophysical activity, dry holes, drilling and equipping exploratory wells, and the cost of retaining undeveloped leaseholds.

- Development costs include costs incurred to gain access to and prepare development well locations for drilling and to drill and equip development wells.

RESULTS OF OPERATIONS

	FOR THE YEAR ENDED DECEMBER 31, 2003	2002*	2001*
		(MILLIONS)	
Revenues:			
Oil and gas revenues	$ 611.9	$ 683.0	$ 408.4
Other revenues	168.8	189.0	171.2
Total revenues	780.7	872.0	579.6
Costs:			
Production costs	138.3	119.5	79.3
General & administrative	54.4	62.9	40.1
Exploration expenses	7.1	13.9	10.1
Depreciation, depletion & amortization	170.2	191.0	94.0
Property impairments	--	8.4	7.2
Gains on sales of interests in oil and gas properties	(134.8)	(141.7)	--
Other expenses	102.1	109.2	138.7
Total costs	337.3	363.2	369.4
Results of operations	443.4	508.8	210.2
Equity earnings	--	--	8.5
Provision for income taxes	(169.6)	(186.9)	(80.4)
Exploration and production net income	$ 273.8	$ 321.9	$ 138.3

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* Certain amounts have been reclassified to conform to current presentation.

- Results of operations for producing activities consist of all related domestic activities within the Exploration & Production reporting unit, including those operations that qualified for presentation as discontinued operations within our Consolidated Statement of Operations. Included above are the pretax results of operations and gains on sales of assets, reported as discontinued operations, of $60.2 million in 2003, $11.9 million in 2002 and $2.3 million in 2001.

- Oil and gas revenues consist primarily of natural gas production sold to the Power subsidiary and includes the impact of intercompany hedges.

- Other revenues and other expenses consist of activities within the Exploration & Production segment that are not a direct part of the producing activities. These non-producing activities include acquisition and disposition of other working interest and royalty interest gas and the movement of gas from the wellhead to the tailgate of the respective plants for sale to the Power subsidiary or third party purchasers. In addition, other revenues include recognition of income from transactions which transferred certain non-operating benefits to a third party.

- Production costs consist of costs incurred to operate and maintain wells and related equipment and facilities used in the production of petroleum liquids and natural gas. These costs also include production related taxes other than income taxes, and administrative expenses related to the production activity. Excluded are depreciation, depletion and amortization of capitalized acquisition, exploration and development costs.

- Exploration expenses include unsuccessful exploratory dry hole costs, leasehold impairment, geological and geophysical expenses and the cost of retaining undeveloped leaseholds.

- Depreciation, depletion and amortization includes depreciation of support equipment.

PROVED RESERVES

	2003	2002	2001
		(BCFE)	
Proved reserves at beginning of period	2,834	3,178	1,202
Revisions	(5)	(87)	(69)
Purchases	38	--	1,949
Extensions and discoveries	412	385	239
Production	(186)	(211)	(131)
Sale of minerals in place	(390)	(431)	(12)
Proved reserves at end of period	2,703	2,834	3,178
Proved developed reserves at end of period	1,165	1,368	1,599

- The SEC defines proved oil and gas reserves (Rule 4-10(a) of Regulation S-X) as the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Our proved reserves consist of two categories, proved developed reserves and proved undeveloped reserves. Proved developed reserves are currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or borehole stimulation treatments. Proved undeveloped reserves are those reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Proved reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled or where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

- Natural gas reserves are computed at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit. Crude oil reserves are insignificant and have been included in the proved reserves on a basis of billion cubic feet equivalents (Bcfe).

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

The following is based on the estimated quantities of proved reserves and the year-end prices and costs. The average year end natural gas prices used in the following estimates were $5.28, $3.85, and $2.31 per mmcfe at December 31, 2003, 2002 and 2001, respectively. Future income tax expenses have been computed considering available carryforwards and credits and the appropriate statutory tax rates. The discount rate of 10 percent is as prescribed by SFAS No. 69. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development and production costs. Of the $1,303 million of future development costs, $192 million, $277 million and $186 million are estimated to be spent in 2004, 2005 and 2006, respectively.

Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and timing of development expenditures. Such reserve estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	AT DECEMBER 31, 2003	2002
	(MILLIONS)	
Future cash inflows	$ 14,268	$ 10,904
Less:		
Future production costs	2,434	2,828
Future development costs	1,303	1,215
Future income tax provisions	3,858	2,346
Future net cash flows	6,673	4,515
Less 10 percent annual discount for estimated timing of cash flows	3,324	2,243
Standardized measure of discounted future net cash flows	$ 3,349	$ 2,272

SOURCES OF CHANGE IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	2003	2002	2001
	(MILLIONS)		
Standardized measure of discounted future net cash flows beginning of period	$ 2,272	$ 1,432	$ 2,720
Changes during the year:			
Sales of oil and gas produced, net of operating costs	(567)	(322)	(270)
Net change in prices and production costs	2,001	1,602	(3,945)
Extensions, discoveries and improved recovery, less estimated future costs	901	546	153
Development costs incurred during year	187	374	199
Changes in estimated future development costs	(159)	(326)	(41)
Purchase of reserves in place, less estimated future costs	78	--	1,069
Sales of reserves in place, less estimated future costs	(855)	(611)	(8)
Revisions of previous quantity estimates	(11)	(123)	(43)
Accretion of discount	341	203	426
Net change in income taxes	(773)	(537)	1,077
Other	(66)	34	95
Net changes	1,077	840	(1,288)
Standardized measure of discounted future net cash flows end of period	$ 3,349	$ 2,272	$ 1,432

THE WILLIAMS COMPANIES, INC.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

	BEGINNING BALANCE	ADDITIONS: CHARGED TO COSTS AND EXPENSES	ADDITIONS: OTHER	DEDUCTIONS	ENDING BALANCE
Year ended December 31, 2003:					
Allowance for doubtful accounts -- Accounts and notes receivables(a)	$ 111.8	$ 7.3	$ 7.9(j)	$ 14.8(c)	$ 112.2
Price-risk management credit reserves(a)	250.4	2.6(f)	--	213.2(i)	39.8
Refining and processing plant major maintenance accrual(b)	2.7	1.4	--	--	4.1
Year ended December 31, 2002:					
Allowance for doubtful accounts -- Accounts and notes receivables(a)	251.8	22.4	--	162.4(c)	111.8
Other noncurrent assets(a)	103.2	256.0	1,720.0(e)	2,079.2(c)	--
Price-risk management credit reserves(a)	648.2	(397.8)(f)	--	--	250.4
Refining and processing plant major maintenance accrual(b)	1.2	1.5	--	--	2.7
Year ended December 31, 2001:					
Allowance for doubtful accounts -- Accounts and notes receivables(a)	6.9	98.4	145.6(g)	(.9)(c)	251.8
Other noncurrent assets(a)	--	103.2	--	--	103.2
Price-risk management credit reserves(a)	60.9	728.5(f)	(141.2)(h)	--	648.2
Refining and processing plant major maintenance accrual(b)	6.0	1.2	--	6.0(d)	1.2

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(a) Deducted from related assets.

(b) Included in liabilities.

(c) Represents balances written off, net of recoveries and reclassifications.

(d) Represents payments made.

(e) Reflects a reclassification of amounts included in the liability for Guarantees and payment obligations related to WilTel at December 31, 2002 (see Note 2 of Notes to Consolidated Financial Statements).

(f) Included in revenue.

(g) Reflects a reclassification of the reserve related to Enron from Price-risk management credit reserves to Allowance for doubtful accounts -- Accounts and notes receivable and amounts related to acquisitions of businesses.

(h) Reflects a reclassification of the reserve related to Enron from Price-risk management credit reserves to Allowance for doubtful accounts -- Accounts and notes receivable.

(i) Reflects cumulative effect of change in accounting principle related to EITF 02-3 (see Note 1 of Notes to Consolidated Financial Statements).

(j) Reflects allowances for accounts receivable charged to costs and expenses for a discontinued operation whose receivables were not held for sale.

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EXHIBIT 99.3

THE WILLIAMS COMPANIES, INC.
CONSOLIDATED STATEMENT OF OPERATIONS
(UNAUDITED)

(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS)	THREE MONTHS ENDED MARCH 31, 2004	2003*
Revenues:		
Power	$ 2,296.4	$ 3,781.5
Gas Pipeline	359.0	339.6
Exploration & Production	165.2	243.9
Midstream Gas & Liquids	627.3	865.4
Other	12.6	28.0
Intercompany eliminations	(395.0)	(482.3)
Total revenues	3,065.5	4,776.1
Segment costs and expenses:		
Costs and operating expenses	2,689.9	4,423.6
Selling, general and administrative expenses	84.4	105.6
Other expense - net	8.4	.7
Total segment costs and expenses	2,782.7	4,529.9
General corporate expenses	32.0	22.9
Operating income (loss):		
Power	(11.1)	(130.5)
Gas Pipeline	143.9	148.5
Exploration & Production	48.6	111.7
Midstream Gas & Liquids	103.6	115.4
Other	(2.2)	1.1
General corporate expenses	(32.0)	(22.9)
Total operating income	250.8	223.3
Interest accrued	(243.3)	(352.8)
Interest capitalized	4.0	11.9
Interest rate swap loss	(8.1)	(2.8)
Investing income	10.3	46.3
Minority interest in income of consolidated subsidiaries	(4.8)	(3.5)
Other income - net	.9	22.1
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	9.8	(55.5)
Provision (benefit) for income taxes	11.3	(12.4)
Loss from continuing operations	(1.5)	(43.1)
Income (loss) from discontinued operations	11.4	(10.1)
Income (loss) before cumulative effect of change in accounting principles	9.9	(53.2)
Cumulative effect of change in accounting principles	-	(761.3)
Net income (loss)	9.9	(814.5)
Preferred stock dividends	-	6.8
Income (loss) applicable to common stock	$ 9.9	$ (821.3)
Basic and diluted earnings (loss) per common share:		
Loss from continuing operations	$ -	$ (.10)
Income (loss) from discontinued operations	.02	(.02)
Income (loss) before cumulative effect of change in accounting principles	.02	(.12)
Cumulative effect of change in accounting principles	-	(1.47)
Net income (loss)	$ .02	$ (1.59)
Weighted-average shares (thousands)	519,485	517,652
Cash dividends per common share	$ .01	$ .01

* Certain amounts have been reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

See accompanying notes.

THE WILLIAMS COMPANIES, INC.
CONSOLIDATED BALANCE SHEET
(UNAUDITED)

(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS)	MARCH 31, 2004	DECEMBER 31, 2003*
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,997.8	$ 2,315.7
Restricted cash	55.7	47.1
Restricted investments	283.6	93.2
Accounts and notes receivable less allowance of $102.8 ($112.2 in 2003)	1,483.8	1,613.2
Inventories	204.0	242.9
Derivative assets	4,037.1	3,166.8
Margin deposits	639.0	553.9
Assets of discontinued operations	172.7	441.3
Deferred income taxes	104.2	106.6
Other current assets and deferred charges	146.1	214.3
Total current assets	9,124.0	8,795.0
Restricted cash	142.3	159.8
Restricted investments	-	288.1
Investments	1,390.0	1,463.6
Property, plant and equipment, at cost	15,846.4	15,752.3
Less accumulated depreciation and depletion	(4,149.2)	(4,018.3)
	11,697.2	11,734.0
Derivative assets	3,386.8	2,495.6
Goodwill	1,014.5	1,014.5
Assets of discontinued operations	336.5	345.1
Other assets and deferred charges	698.9	726.1
Total assets	$ 27,790.2	$ 27,021.8
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Notes payable	$ -	$ 3.3
Accounts payable	983.0	1,228.0
Accrued liabilities	830.5	944.4
Liabilities of discontinued operations	42.7	95.7
Derivative liabilities	4,083.4	3,064.2
Long-term debt due within one year	442.9	935.2
Total current liabilities	6,382.5	6,270.8
Long-term debt	10,824.8	11,039.8
Deferred income taxes	2,405.0	2,453.4
Derivative liabilities	3,130.5	2,124.1
Other liabilities and deferred income	925.6	947.5
Contingent liabilities and commitments (Note 11)		
Minority interests in consolidated subsidiaries	87.7	84.1
Stockholders' equity:		
Common stock, $1 per share par value, 960 million shares authorized, 523 million issued in 2004, 521.4 million issued in 2003	523.0	521.4
Capital in excess of par value	5,205.8	5,195.1
Accumulated deficit	(1,422.0)	(1,426.8)
Accumulated other comprehensive loss	(209.1)	(121.0)
Other	(25.0)	(28.0)
	4,072.7	4,140.7
Less treasury stock (at cost), 3.2 million shares of common stock in 2004 and 2003	(38.6)	(38.6)
Total stockholders' equity	4,034.1	4,102.1
Total liabilities and stockholders' equity	$ 27,790.2	$ 27,021.8

* Certain amounts have been reclassified as described in Note 2 to Consolidated Financial Statements.

See accompanying notes.

THE WILLIAMS COMPANIES, INC.
CONSOLIDATED STATEMENT OF CASH FLOWS
(UNAUDITED)

	THREE MONTHS ENDED MARCH 31, 2004	THREE MONTHS ENDED MARCH 31, 2003*
	(MILLIONS)	
OPERATING ACTIVITIES:		
Loss from continuing operations	$ (1.5)	$ (43.1)
Adjustments to reconcile to cash provided (used) by operations:		
Depreciation, depletion and amortization	160.4	164.5
Provision (benefit) for deferred income taxes	3.8	(23.4)
Provision for loss on investments, property and other assets	7.4	12.0
Net (gain) loss on disposition of assets	1.3	(.6)
Provision for uncollectible accounts	(3.8)	(2.0)
Minority interest in income of consolidated subsidiaries	4.8	3.5
Amortization of stock-based awards	4.1	17.2
Accrual for fixed rate interest included in the RMT note payable	-	33.0
Amortization of deferred set-up fee and fixed rate interest on RMT note payable	-	64.3
Cash provided (used) by changes in current assets and liabilities:		
Restricted cash	2.8	2.5
Accounts and notes receivable	161.2	(37.7)
Inventories	38.9	39.6
Margin deposits	(85.4)	(48.7)
Other current assets and deferred charges	66.9	(69.6)
Accounts payable	(214.0)	(83.4)
Accrued liabilities	(114.5)	(178.9)
Changes in current and noncurrent derivative assets and liabilities	114.5	(10.9)
Changes in noncurrent restricted cash	(.1)	(.5)
Other, including changes in noncurrent assets and liabilities	3.1	(20.8)
Net cash provided (used) by operating activities of continuing operations	149.9	(183.0)
Net cash provided (used) by operating activities of discontinued operations	(47.1)	86.3
Net cash provided (used) by operating activities	102.8	(96.7)
FINANCING ACTIVITIES:		
Payments of notes payable	(3.3)	(.1)
Proceeds from long-term debt	-	176.5
Payments of long-term debt	(707.7)	(360.0)
Proceeds from issuance of common stock	4.8	-
Dividends paid	(5.2)	(12.0)
Payments of debt issuance costs	-	(6.9)
Payments/dividends to minority interests	(1.2)	(.4)
Changes in restricted cash	6.3	(250.6)
Changes in cash overdrafts	(27.4)	(31.9)
Other - net	(.5)	.1
Net cash used by financing activities of continuing operations	(734.2)	(485.3)
Net cash used by financing activities of discontinued operations	(.6)	(81.0)
Net cash used by financing activities	(734.8)	(566.3)
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(127.8)	(235.1)
Proceeds from dispositions	.9	43.4
Purchases of investments/advances to affiliates	(.4)	(5.7)
Purchases of restricted investments	(235.9)	-
Proceeds from sales of businesses	279.9	636.2
Proceeds from sale of restricted investments	331.2	-
Proceeds from dispositions of investments and other assets	74.8	.1
Other - net	(9.3)	4.0
Net cash provided by investing activities of continuing operations	313.4	442.9
Net cash used by investing activities of discontinued operations	(.9)	(14.3)
Net cash provided by investing activities	312.5	428.6
Decrease in cash and cash equivalents	(319.5)	(234.4)
Cash and cash equivalents at beginning of period**	2,318.2	1,736.0
Cash and cash equivalents at end of period**	$ 1,998.7	$ 1,501.6

* Certain amounts have been reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

** Includes cash and cash equivalents of discontinued operations of $.9 million, $2.5 million, $98.4 million and $85.6 million at March 31, 2004, December 31, 2003, March 31, 2003 and December 31, 2002, respectively.

See accompanying notes.

1. GENERAL

Company overview and outlook

In February 2003, we outlined our planned business strategy in response to the events that significantly impacted the energy sector and our company during late 2001 and much of 2002, including the collapse of Enron and the severe decline of the telecommunications industry. The plan focused on migrating to an integrated natural gas business comprised of a strong, but smaller, portfolio of natural gas businesses; reducing debt; and increasing our liquidity through asset sales, strategic levels of financing and reductions in operating costs. The plan was designed to address near-term and medium-term debt and liquidity issues, to de-leverage the company with the objective of returning to investment grade status and to develop a balance sheet and cash flows capable of supporting and ultimately growing our remaining businesses.

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, we successfully executed certain critical components of our plan during 2003. Key execution steps for 2004 and beyond include the completion of planned asset sales, additional reductions of our selling, general and administrative (SG&A) costs, the replacement of our cash-collateralized letter of credit and revolver facility with facilities that do not encumber cash and continuation of efforts to exit from the Power business. Projected asset sales are expected to generate proceeds of approximately $800 million in 2004 and include the Alaska refinery and certain Midstream Gas & Liquids (Midstream) assets including the straddle plants in western Canada. On March 31, 2004, we completed the sale of our Alaska refinery and related assets for approximately $304 million (see Note 5).

In April 2004, we entered into two new unsecured credit facilities totaling $500 million, which will be used primarily for issuing letters of credit. During April 2004, use of these new facilities released approximately $500 million of restricted cash, restricted investments and margin deposits (see Note 10). Also, on May 3, 2004, we entered into a new three-year $1 billion secured revolving credit facility. The revolving credit facility is secured by certain Midstream assets and a guarantee from Williams Gas Pipeline Company, LLC. (WGP) (see Note 10).

Power Business Status

Since mid-2002, we have been pursuing a strategy of exiting the Power business and have worked with financial advisors to assist with this effort. To date, several factors have contributed to the difficulty of achieving a complete exit from this business, including the following with respect to the wholesale power industry:

- oversupply position in most markets expected through the balance of the decade;
- slow North American gas supply response to high gas prices; and
- expectations of hybrid regulated/deregulated market structure for several years.

As a result of these factors and the size of our Power business, the number of financially viable parties expressing an interest in purchasing the entire business has been limited. Additionally, the current and near term view of the wholesale power market, which we interpret as depressed, has strongly influenced these parties' view of value and related risk associated with this business.

Because market conditions may change, and we cannot determine the impact of this on a buyer's point of view, amounts ultimately received in any portfolio sale, contract liquidation or realization may be significantly different from the estimated economic value or carrying values reflected in the Consolidated Balance Sheet. In addition, our tolling agreements are not derivatives and thus have no carrying value in the Consolidated Balance Sheet pursuant to the application of Emerging Issues Task Force (EITF) Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities," (EITF 02-3). Based on current market conditions, certain of these agreements are forecasted to realize significant future losses. It is possible that we may sell contracts for less than their carrying value or enter into agreements to terminate certain obligations, either of which could result in significant future loss recognition or reductions of future cash flows.

We continue to evaluate alternatives and discuss our plans and operating strategy for the Power business with our Board of Directors. As an alternative to continuing a plan of pursuing a complete exit from the Power business, we are evaluating whether the benefits of realizing the positive cash flows expected to be generated by this business through continued ownership exceed the benefits of a sale at a depressed price. If we pursue this alternative, we expect to continue our current program of managing this business to minimize financial risk, generate cash and manage existing contractual commitments.

Other

Our accompanying interim consolidated financial statements do not include all notes in 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, as restated and amended. The accompanying unaudited financial statements include all normal recurring adjustments and others, including asset impairments, loss accruals, and the change in accounting principles which, in the opinion of our management, are necessary to present fairly our financial position at March 31, 2004, and results of operations and cash flows for the three months ended March 31, 2004 and 2003.

During the second quarter of 2003, we corrected the accounting treatment previously applied to certain third-party derivative contracts during 2002 and 2001. We previously disclosed this in our Form 10-Q for the second quarter of 2003 and in our Form 10-K for the year ended December 31, 2003. Results for first-quarter 2003 include $13.7 million of revenue attributable to the prior periods. Our management, after consultation with our independent auditor, concluded that the effect of the previous accounting treatment was not material to 2003 and earlier periods and the trend of earnings.

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.

2. BASIS OF PRESENTATION

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, financial position and cash flows of the following components as discontinued operations (see Note 5):

- retail travel centers concentrated in the Midsouth, part of the previously reported Petroleum Services segment;
- refining and marketing operations in the Midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;
- Texas Gas Transmission Corporation, previously one of Gas Pipeline's segments;
- natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment;
- bio-energy operations, part of the previously reported Petroleum Services segment;
- our general partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;
- the Colorado soda ash mining operations, part of the previously reported International segment;
- certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream segment;
- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment;
- Gulf Liquids New River Project LLC, previously part of the Midstream segment; and
- our straddle plants in western Canada, previously part of the Midstream segment.

Notes (Continued)

Unless indicated otherwise, the information in the Notes to the Consolidated Financial Statements relates to our continuing operations. We expect that other components of our business may be classified as discontinued operations in the future as those operations are sold or classified as held-for-sale.

We have restated all segment information in the Notes to Consolidated Financial Statements for the prior period presented to reflect the discontinued operations noted above, consistent with the presentation in our 2003 Form 10-K, as restated and amended. Certain other statement of operations, balance sheet and cash flow amounts have been reclassified to conform to the current classifications.

3. CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES

Energy commodity risk management and trading activities and revenues

Effective January 1, 2003, we adopted EITF 02-3. As a result of initial application of this Issue, we reduced net income by $762.5 million (net of a $471.4 million benefit for income taxes) in first-quarter 2003. Approximately $755 million of the reduction in net income relates to Power, with the remainder relating to Midstream. The reduction of net income is reported as a cumulative effect of a change in accounting principle. The change resulted primarily from power tolling, load serving, transportation and storage contracts not meeting the definition of a derivative and no longer being reported at fair value.

Asset retirement obligations

Effective January 1, 2003, we also adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." As required by the new standard, we recorded liabilities equal to the present value of expected future asset retirement obligations at January 1, 2003. As a result of the adoption of SFAS No. 143, we recorded a credit to earnings of $1.2 million (net of a $.1 million provision for income taxes) reflected as a cumulative effect of a change in accounting principle. In connection with adoption of SFAS No. 143, we changed our method of accounting to include salvage value of equipment related to producing wells in the calculation of depreciation. The impact of this change is included in the effect of adoption.

4. PROVISION (BENEFIT) FOR INCOME TAXES

The provision (benefit) for income taxes from continuing operations includes:

	THREE MONTHS ENDED MARCH 31,	
	2004	2003
	(MILLIONS)	
Current:		
Federal	$ 3.2	$ 6.3
State	1.8	4.7
Foreign	2.5	-
	7.5	11.0
Deferred:		
Federal	(.6)	(16.6)
State	2.1	(3.0)
Foreign	2.3	(3.8)
	3.8	(23.4)
Total provision (benefit)	$ 11.3	$ (12.4)

The effective income tax rate for the three months ended March 31, 2004, is greater than the federal statutory rate due primarily to an accrual for income tax contingencies, net foreign operations, and state income taxes.

The effective income tax rate for the three months ended March 31, 2003, is less than the federal statutory rate (less tax benefit) due primarily to an accrual for income tax contingencies and state income taxes.

Notes (Continued)

5. DISCONTINUED OPERATIONS

During 2002, we began the process of selling assets and/or businesses to address liquidity issues. The businesses discussed below represent components that have been sold or approved for sale by our Board of Directors as of March 31, 2004; therefore, their results of operations (including any impairments, gains or losses), financial position and cash flows have been reflected in the consolidated financial statements and notes as discontinued operations.

During second-quarter 2004, our Board of Directors approved a plan to negotiate and facilitate the sale of our three natural gas liquid extraction plants (straddle plants) in western Canada. These assets were previously written down to estimated fair value, resulting in a $36.8 million impairment in fourth-quarter 2002 and an additional $41.7 million impairment in fourth-quarter 2003. In 2004, the fair value of the assets increased substantially due primarily to renegotiation of certain customer contracts and a general improvement in the market for processing assets. These operations were part of the Midstream segment. Consequently, the results of operations of the straddle plants have been reclassified to discontinued operations in the consolidated financial statements and in the tables below. All prior periods reflect this classification.

SUMMARIZED RESULTS OF DISCONTINUED OPERATIONS

The following table presents the summarized results of discontinued operations for the three months ended March 31, 2004 and March 31, 2003. Income from discontinued operations before income taxes for the first quarter of 2004 includes a charge of $17.4 million to adjust our accrued liability associated with certain Quality Bank litigation matters (see Note 11).

	THREE MONTHS ENDED MARCH 31, 2004	THREE MONTHS ENDED MARCH 31, 2003
	(MILLIONS)	
Revenues	$ 294.3	$ 1,217.9
Income from discontinued operations before income taxes	11.1	96.8
(Impairments) and gain (loss) on sales - net	6.9	(117.3)
Benefit (provision) for income taxes	(6.6)	10.4
Income (loss) from discontinued operations	$ 11.4	$ (10.1)

SUMMARIZED ASSETS AND LIABILITIES OF DISCONTINUED OPERATIONS

The following table presents the summarized assets and liabilities of discontinued operations as of March 31, 2004 and December 31, 2003. The December 31, 2003, balances include the assets and liabilities of the Canadian straddle plants, the Gulf Liquids New River Project LLC (Gulf Liquids) and the Alaska refining, retail and pipeline operations. The March 31, 2004 balances include the Canadian straddle plants, Gulf Liquids and the remaining working capital amounts of the Alaska refining, retail and pipeline operations. The assets and liabilities from discontinued operations are reflected on the Consolidated Balance Sheet as current beginning in the period they are both approved for sale and expected to be sold within twelve months.

	MARCH 31, 2004	DECEMBER 31, 2003
	(MILLIONS)	
Total current assets	$ 112.6	$ 175.4
Property, plant and equipment -- net	395.2	609.0
Other non-current assets	1.4	2.0
Total non-current assets	396.6	611.0
Total assets	$ 509.2	$ 786.4
Long-term debt due within one year	$ .6	$ 1.2
Other current liabilities	40.4	81.5
Total current liabilities	41.0	82.7
Long-term debt	-	.3
Other non-current liabilities	1.7	12.7
Total non-current liabilities	1.7	13.0
Total liabilities	$ 42.7	$ 95.7

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HELD FOR SALE AT MARCH 31, 2004

Gulf Liquids New River Project LLC

During second-quarter 2003, our Board of Directors approved a plan authorizing management to negotiate and facilitate a sale of the assets of Gulf Liquids. The Gulf Liquids assets were previously written down to their estimated fair value less cost to sell at December 31, 2003. We estimated fair value based on a probability-weighted analysis of various scenarios, including expected sales prices, discounted cash flows and salvage valuations. During first-quarter 2004, we initiated a second bid process and expect the sale of these operations to be completed in mid-2004. These operations were part of the Midstream segment.

2004 COMPLETED TRANSACTIONS

Alaska refining, retail and pipeline operations

On March 31, 2004, we completed the sale of our Alaska refinery, retail and pipeline and related assets for approximately $304 million (consisting of $279 million in cash and a $25 million short-term receivable), subject to closing adjustments for items such as the value of petroleum inventories. Throughout the sales negotiation process, we regularly reassessed the estimated fair value of these assets based on information obtained from the sales negotiations using a probability-weighted approach. We recognized a $3.6 million gain on the sale. The gain and an $8 million first-quarter 2003 impairment charge are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

2003 COMPLETED TRANSACTIONS

Canadian liquids operations

During the third quarter of 2003, we completed the sale of certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at our Redwater, Alberta plant for total proceeds of $246 million in cash. These operations were part of the Midstream segment.

Soda ash operations

On September 9, 2003, we completed the sale of our soda ash mining facility located in Colorado. During 2003, ongoing sale negotiations continued to provide new information regarding estimated fair value, and, as a result, the carrying value of these assets was adjusted periodically as necessary. A first-quarter 2003 impairment charge of $5 million is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. The soda ash operations were part of the previously reported International segment.

Williams Energy Partners

On June 17, 2003, we completed the sale of our 100 percent general partnership interest and 54.6 percent limited partner investment in Williams Energy Partners for approximately $512 million in cash and assumption by the purchasers of $570 million in debt. In December 2003, we received additional cash proceeds of $20 million following the occurrence of a contingent event.

Bio-energy facilities

On May 30, 2003, we completed the sale of our bio-energy operations for approximately $59 million in cash. These operations were part of the previously reported Petroleum Services segment.

Natural gas properties

On May 30, 2003, we completed the sale of natural gas exploration and production properties in the Raton Basin in southern Colorado and the Hugoton Embayment in southwestern Kansas. This sale included all of our interests within these basins. These properties were part of the Exploration & Production segment.

Texas Gas

On May 16, 2003, we completed the sale of Texas Gas Transmission Corporation for $795 million in cash and the assumption by the purchaser of $250 million in existing Texas Gas debt. We recorded a $109 million impairment charge in first-quarter 2003 reflecting the excess of the carrying cost of the long-lived assets over our estimate of fair value based on our assessment of the expected sales price pursuant to the purchase and sale agreement. The impairment charge is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. Texas Gas was a segment within Gas Pipeline.

Midsouth refinery and related assets

On March 4, 2003, we completed the sale of our refinery and other related operations located in Memphis, Tennessee for $455 million in cash. These assets were previously written down to their estimated fair value less cost to sell at December 31, 2002. We recognized a pre-tax gain on sale of $4.7 million in the first quarter of 2003. The gain on sale is included in (impairments) and gain (loss) on sale in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

Williams travel centers

On February 27, 2003, we completed the sale of our travel centers for approximately $189 million in cash. We had previously written these assets down to their estimated fair value to sell at December 31, 2002, and did not recognize a significant gain or loss on the sale. These operations were part of the previously reported Petroleum Services segment.

6. EARNINGS (LOSS) PER SHARE

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

	THREE MONTHS ENDED MARCH 31, 2004	THREE MONTHS ENDED MARCH 31, 2003
	(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS; SHARES IN THOUSANDS)	
Loss from continuing operations	$ (1.5)	$ (43.1)
Convertible preferred stock dividends	-	(6.8)
Loss from continuing operations available to common stockholders for basic and diluted earnings per share	(1.5)	(49.9)
Basic and diluted weighted-average shares	519,485	517,652
Loss per share from continuing operations:		
Basic and diluted	$ -	$ (.10)

For the periods ended March 31, 2004 and 2003, diluted earnings (loss) per share is the same as the basic calculation as each period presented has a loss from continuing operations. Shares, which would otherwise have been included in the diluted earnings (loss) per share, have been excluded from the computation. Inclusion of these shares, which are discussed below, would be antidilutive.

For the three months ended March 31, 2004, approximately 27.5 million weighted-average shares related to the assumed conversion of convertible debentures, as well as the related interest, have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive. In addition, approximately 3.8 million weighted-average stock options and approximately 2.4 million weighted-average unvested deferred shares have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive.

For the three months ended March 31, 2003, approximately 1.7 million weighted-average stock options, approximately 14.7 million weighted-average shares related to the assumed conversion of 9 7/8 percent cumulative convertible preferred stock and approximately 3.2 million weighted-average unvested deferred shares, that otherwise would have been included, have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive.

7. EMPLOYEE BENEFIT PLANS

Net pension and other postretirement benefit expense for the three months ended March 31, 2004 and 2003 is as follows:

	PENSION BENEFITS THREE MONTHS ENDED MARCH 31, 2004	PENSION BENEFITS THREE MONTHS ENDED MARCH 31, 2003	OTHER POSTRETIREMENT BENEFITS THREE MONTHS ENDED MARCH 31, 2004	OTHER POSTRETIREMENT BENEFITS THREE MONTHS ENDED MARCH 31, 2003
	(MILLIONS)			
Service cost	$ 7.0	$ 6.5	$ 1.5	$ 1.7
Interest cost	14.5	13.4	5.7	6.4
Expected return on plan assets	(14.9)	(13.8)	(3.1)	(3.5)
Amortization of transition obligation	-	-	.6	.7
Amortization of prior service cost (credit)	(.7)	(.6)	.2	.2
Recognized net actuarial loss	3.7	3.4	-	-
Regulatory asset amortization (deferral)	1.1	.1	1.6	2.7
Settlement/ curtailment expense	-	1.5	-	-
Net periodic pension and postretirement benefit expense	$ 10.7	$ 10.5	$ 6.5	$ 8.2

As previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2003, we expect to contribute approximately $60 million to our pension plans and approximately $15 million to our other postretirement benefit plans in 2004. As of March 31, 2004, $.7 million has been contributed to our pension plans and $2.5 million has been contributed to our other postretirement benefit plans. We presently anticipate contributing approximately an additional $59 million to fund our pension plans in 2004 for a total of approximately $60 million. We presently anticipate contributing approximately an additional $12 million to our other postretirement benefit plans in 2004 for a total of approximately $15 million.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act introduces a prescription drug benefit under Medicare (Medicare Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Our health care plan for retirees includes prescription drug coverage. Management is evaluating the impact of the Act on the future obligations of the plan. In accordance with FASB Staff Position No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," the provisions of the Act are not reflected in any measures of benefit obligations or other postretirement benefit expense in the financial statements or accompanying notes. Authoritative guidance on the accounting for a federal subsidy is pending. That guidance, as currently drafted would require any change in obligation attributable to prior service be deferred and recognized over future periods if the plan is deemed to be actuarially equivalent and eligible for the subsidy. As proposed, this guidance would be effective for us beginning July 1, 2004.

Notes (Continued)

8. STOCK-BASED COMPENSATION

Employee stock-based awards are accounted for under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25) and related interpretations. Fixed-plan common stock options generally do not result in compensation expense because the exercise price of the stock options equals the market price of the underlying stock on the date of grant. The following table illustrates the effect on net income (loss) and earnings (loss) per share if we had applied the fair value recognition provisions of SFAS No. 123 "Accounting for Stock-Based Compensation."

	THREE MONTHS ENDED MARCH 31, 2004	THREE MONTHS ENDED MARCH 31, 2003
	(MILLIONS)	
Net income (loss), as reported	$ 9.9	$ (814.5)
Add: Stock-based employee compensation included in the Consolidated Statement of Operations, net of related tax effects	4.4	10.6
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(7.4)	(14.7)
Pro forma net income (loss)	$ 6.9	$ (818.6)
Earnings (loss) per share:		
Basic-as reported	$ .02	$ (1.59)
Basic-pro forma	$ .01	$ (1.59)
Diluted-as reported	$ .02	$ (1.59)
Diluted-pro forma	$ .01	$ (1.59)

Pro forma amounts for 2004 include compensation expense from awards of our company stock made in 2004, 2003, 2002 and 2001. Also included in the 2004 pro forma expense is $1 million of incremental expense associated with the stock option exchange program described below. Pro forma amounts for 2003 include compensation expense from awards made in 2003, 2002 and 2001.

Since compensation expense for stock options is recognized over the future years' vesting period for pro forma disclosure purposes and additional awards are generally made each year, pro forma amounts may not be representative of future years' amounts.

On May 15, 2003, our shareholders approved a stock option exchange program. Under this exchange program, eligible employees were given a one-time opportunity to exchange certain outstanding options for a proportionately lesser number of options at an exercise price to be determined at the grant date of the new options. Surrendered options were cancelled June 26, 2003, and replacement options were granted on December 29, 2003. We did not recognize any expense pursuant to the stock option exchange. However, for purposes of pro forma disclosures, we recognized additional expense related to these new options. The remaining expense on the cancelled options will be amortized through year-end 2004.

9. INVENTORIES

Inventories at March 31, 2004 and December 31, 2003 are as follows:

	MARCH 31, 2004	DECEMBER 31, 2003
	(MILLIONS)	
Finished goods:		
Refined products	$ 19.1	$ 8.0
Natural gas liquids	50.7	40.4
	69.8	48.4
Natural gas in underground storage	74.4	132.5
Materials, supplies and other	59.8	62.0
	$ 204.0	$ 242.9

Notes (Continued)

10. DEBT AND BANKING ARRANGEMENTS

NOTES PAYABLE AND LONG-TERM DEBT

Notes payable and long-term debt at March 31, 2004 and December 31, 2003, are as follows:

	WEIGHTED-AVERAGE INTEREST RATE (1)	MARCH 31, 2004	DECEMBER 31, 2003
		(MILLIONS)	
Secured notes payable	-%	$ -	$ 3.3
Long-term debt:			
Secured long-term debt			
Notes, 6.62%-9.45%, payable through 2016	8.0%	$ 234.7	$ 243.7
Notes, adjustable rate, payable through 2016	3.3%	596.2	602.5
Unsecured long-term debt			
Debentures, 5.5%-10.25%, payable through 2033	7.0%	1,645.6	1,645.2
Notes, 6.125%-9.25%, payable through 2032 (2)	7.5%	8,712.0	9,404.3
Other, payable through 2007	4.0%	79.2	79.3
		11,267.7	11,975.0
Long-term debt due within one year		(442.9)	(935.2)
Total long-term debt		$ 10,824.8	$ 11,039.8

(1) At March 31, 2004.

(2) Includes $1.1 billion of 6.5 percent notes payable 2007, subject to remarketing in November 2004, discussed below.

Long-term debt includes $1.1 billion of 6.5 percent notes, payable in 2007, which are subject to remarketing in 2004. These FELINE PACS include equity forward contracts that require the holder to purchase shares of our common stock in 2005. If a remarketing is unsuccessful in 2004 and a second remarketing in February 2005 is unsuccessful as defined in the offering document for the FELINE PACS, then we could exercise our right to foreclose on the notes in order to satisfy the obligation of the holders of the equity forward contracts requiring the holder to purchase our common stock. This would be a non-cash transaction.

On February 25, 2004, our Exploration & Production segment amended its $500 million secured variable rate note. The amendment reduced the floating interest rate from the London InterBank Offered Rate (LIBOR) plus 3.75 percent to LIBOR plus 2.5 percent. The amendment also extended the maturity date from May 30, 2007 to May 30, 2008. The amendment provides for an additional reduction in the interest rate by 25 basis points, or 0.25 percent, if we meet certain credit-rating requirements. The significant covenants were not altered by the amendment.

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, 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.

Revolving credit and letter of credit facilities

The interest rate on our current $800 million secured revolving and letter of credit facility is variable at LIBOR plus .75 percent, or 1.84 percent at March 31, 2004. As of March 31, 2004, letters of credit totaling $268 million have been issued by the participating financial institutions under this facility and remain outstanding. No revolving credit loans were outstanding. At March 31, 2004, the amount of restricted investments securing this facility was $283.6 million, which collateralized the facility at approximately 106 percent.

In April 2004, we entered into two unsecured bank revolving credit facilities totaling $500 million. These facilities provide for both borrowings and issuing letters of credit, but will be used primarily for issuing letters of credit. We are required to pay to the bank fixed fees at a weighted average rate of 3.64 percent on the total committed amount of the facilities. In addition, we pay interest on any borrowings at a fluctuating rate comprised of either a base rate or LIBOR. We were able to obtain the unsecured credit facilities because the bank syndicated its associated credit risk into the institutional investor market via a 144A offering. Upon the occurrence of certain credit events, outstanding letters of credit become cash collateralized creating a borrowing under the facilities, and concurrently the bank can deliver the facilities to the institutional investors, whereby the investors replace the bank as lender under the facilities. Upon such occurrence, we will pay:

- the fixed facility fee at a weighted average rate of 3.19 percent to the investors,

- interest on borrowings under the $400 million facility equal to a fixed rate of 3.57 percent, and

- interest on borrowings under the $100 million facility at a fluctuating LIBOR interest rate.

The bank established trusts funded by the institutional investors, whereby the assets of the trusts serve as collateral to reimburse the bank for our borrowings in the event the facilities are delivered to the investors. We have no asset securitization or collateral requirements under the new facilities. During April 2004, use of these new facilities released approximately $500 million of restricted cash, restricted investments and margin deposits. Significant covenants under these facilities include the following:

- limitations on certain payments, including a limitation on the payment of quarterly dividends to no greater than $.05 per common share (however, we are limited to $.02 per common share under a more restrictive covenant contained in our $800 million 8.625 percent senior unsecured notes);

- limitations on asset sales;

- limitations on the use of proceeds from permitted asset sales;

- limitations on transactions with affiliates; and

- limitations on the incurrence of additional indebtedness and issuance of disqualified stock, unless the fixed charge coverage ratio for our most recently ended four full fiscal quarters is at least 2 to 1, determined on a proforma basis.

On May 3, 2004, we entered into a new three-year, $1 billion secured revolving credit facility which is available for borrowings and letters of credit. Northwest Pipeline Corporation (Northwest Pipeline) and Transcontinental Gas Pipeline Corporation (Transco) have access to $400 million each under the facility. The new facility is secured by certain Midstream assets, including substantially all of our southwest Wyoming, Wamsutter, San Juan Conventional, Manzanares and Torre Alta systems. Additionally, the facility is guaranteed by WGP. Interest is calculated based on a choice of two methods: a fluctuating rate equal to the facilitating bank's base rate plus an applicable margin or a periodic fixed rate equal to LIBOR plus an applicable margin. We are also required to pay a commitment fee based on the unused portion of the facility, currently .375 percent. The applicable margins and commitment fee are based on the relevant borrower's senior unsecured long-term debt ratings. Significant financial covenants under the credit agreement include:

- ratio of Debt to Capitalization no greater than i) 75 percent for the period June 30, 2004 through December 31, 2004, ii) 70 percent for the period after December 31, 2004 through December 31, 2005, and iii) 65 percent for the remaining term of the agreement;

- ratio of Debt to Capitalization no greater than 55 percent for Northwest Pipeline and Transco;

- ratio of EBITDA to Interest, on a rolling four quarter basis (or, in the first year, building up to a rolling four quarter basis), no less than i) 1.5 for the period September 30, 2004 through March 31, 2005, ii) 2.0 for any period after March 31, 2005 through December 31, 2005, and iii) 2.5 for the remaining term of the agreement.

Notes (Continued)

Issuances and retirements

On March 15, 2004, we retired $679 million of senior, unsecured 9.25 percent notes. The amount represented the outstanding balance subsequent to the fourth-quarter 2003 tender which retired $721 million of the original $1.4 billion balance.

A summary of significant retirements, payments and prepayments of long-term debt for the quarter ended March 31, 2004 is as follows:

ISSUE/TERMS	DUE DATE	PRINCIPAL AMOUNT (MILLIONS)
Retirements/payments/prepayments of long-term debt in 2004:		
9.25% senior unsecured notes	2004	$ 678.5
Various notes, 6.62% - 9.45%	2004	22.7
Various notes, adjustable rate	2004	6.3

11. CONTINGENT LIABILITIES AND COMMITMENTS

RATE AND REGULATORY MATTERS AND RELATED LITIGATION

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result of rulings in certain of these proceedings, a portion of the revenues of these subsidiaries has been collected subject to refund. The natural gas pipeline subsidiaries have accrued approximately $5 million for potential refund as of March 31, 2004.

ISSUES RESULTING FROM CALIFORNIA ENERGY CRISIS

Power subsidiaries are 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 have been challenged in various proceedings including those before the FERC. These challenges include refund proceedings, California Independent System Operator (ISO) fines, 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 a settlement with the State of California and others that has resolved each of these issues as to the State, and in February 2004 we announced a settlement with certain California utilities that is expected to resolve these issues as to such utilities. However, certain of these issues remain open as to the FERC and other non-settling parties.

Refund proceedings

We and other suppliers of electricity in the California market are the subject of refund proceedings before the FERC. In December 2000, the FERC issued an order initiating the proceeding, which ultimately (by order dated June 19, 2001) established a refund methodology and set a refund period of October 2, 2000 to June 19, 2001. As a result of a hearing to determine refund liability for the market participants, a FERC administrative law judge issued findings on December 12, 2002, that estimated our refund obligation to the ISO at $192 million, excluding emissions costs and interest. The judge estimated that our refund obligation to the California Power Exchange (PX) was $21.5 million, excluding interest. However, the judge estimated that the ISO owes us $246.8 million, excluding interest, and that the PX owes us $31.7 million, excluding interest, and $2.9 million in charge backs. The estimates did not include $17 million in emissions costs that the judge found we are entitled to use as an offset to the refund liability, and the judge's refund estimates are not based on final mitigated market clearing prices. On March 26, 2003, the FERC acted to largely adopt the judge's order with a change to the gas methodology used to set the clearing price. As a result, Power recorded a first-quarter 2003 charge for refund obligations of $37 million. Net interest income related to amounts due from the counterparties is approximately $8 million through March 31, 2004. On October 16, 2003, the FERC issued an additional refund order granting rehearing in part and denying rehearing in part. This order is not expected to have a material effect on the refund calculation for us. However, pursuant to the October 16 order, the ISO has been ordered to calculate refunds for the market. This study is expected to be complete in early summer, 2004. Although we have entered into a global settlement with the State of California and various other parties that resolves the refund issues among the settling parties for the period of January 17, 2001 to June 19, 2001, we have potential refund exposure to non-settling parties (e.g., various California electric utilities). Therefore, we continue to participate in the FERC refund case and related proceedings. Challenges to virtually every aspect of the refund proceeding, including the refund period, are now pending at the Ninth Circuit Court of Appeals. No schedule has yet been established for hearing the appeals.

On February 25, 2004, we announced a settlement agreement with California utilities, Southern California Edison and Pacific Gas & Electric (PG&E), to resolve our refund liability to the utilities as well as all other known disputes related to the California energy crisis of 2000 and 2001 (the "Utility Settlement"). The Utility Settlement was filed with the FERC on April 27, 2004. Comments and approval are pending. While only these two utilities were originally parties to the Utility Settlement with us, additional parties, including San Diego Gas & Electric, have now opted in and the Utility Settlement includes funding for refunds to all buyers in equal kind in the FERC refund period. Should any buyer opt out of the Utility Settlement, the refund amount in the Utility Settlement would be reduced and we would continue to litigate with that buyer regarding the refund issue and amount. If this settlement is approved, our outstanding receivables for the period of approximately $261 million will be partially offset by our settlement obligation of approximately $136 million. We will receive $108 million of our net $125 million receivable on an expedited basis. These funds will be largely used to repurchase PG&E receivables previously sold to Bear Stearns. The remainder of the receivable, in addition to accrued interest, is expected to be received within a year of the settlement. To be effective, the Utility Settlement must be approved by the FERC and the California Public Utilities Commission. Approval by the FERC will also resolve FERC investigations into physical and economic withholding. The Utility Settlement, if approved, will also resolve any claims by the settling parties regarding these issues. We recorded a charge of approximately $33 million in the fourth quarter of 2003 associated with the terms of this settlement.

In a separate but related proceeding, certain entities have also asked the FERC to revoke our authority to sell power from California-based generating units at market-based rates, to limit us to cost-based rates for future sales from such units and to order refunds of excessive rates, with interest, retroactive to May 1, 2000, and possibly earlier. The Utility Settlement, if approved, will resolve this issue and we will maintain all existing authorities.

ISO fines

On July 3, 2002, the ISO announced fines against several energy producers including us, for failure to deliver electricity during the period December 2000 through May 2001. The ISO fined us $25.5 million during this period, which was offset against our claims for payment from the ISO. These amounts will be adjusted as part of the refund proceeding described above. We believe the vast majority of fines are not justified and have challenged them pursuant to the FERC-approved dispute resolution process contained in the ISO tariff.

Summer 2002 90-day contracts

On May 2, 2002, PacifiCorp filed a complaint with the FERC against Power seeking relief from rates contained in three separate confirmation agreements between PacifiCorp and Power (known as the Summer 2002 90-Day Contracts). PacifiCorp filed similar complaints against three other suppliers. PacifiCorp alleged that the rates contained in the contracts are unjust and unreasonable. On June 26, 2003, the FERC affirmed the administrative law judge's initial decision dismissing the complaints. PacifiCorp has appealed the FERC's order to the United States Court of Appeals for the DC Circuit after the FERC denied rehearing of its order on November 10, 2003.

Investigations of alleged market manipulation

As a result of various allegations and FERC Orders, in 2002 the FERC initiated investigations of manipulation of the California gas and power markets. As they related to us, these investigations included economic and physical withholding, so-called "Enron Gaming Practices" and gas index manipulation.

On February 13, 2002, the FERC issued an Order Directing Staff Investigation commencing a proceeding titled Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices prior to the California parties (who include the California Attorney General, the Electricity Oversight Board, the Public Utilities Commission and two investor-owned utilities) filing of their report. Through the investigation, the FERC intends to determine whether "any entity, including Enron Corporation (Enron) (through any of its affiliates or subsidiaries), manipulated short-term prices for electric energy or natural gas in the West or otherwise exercised undue influence over wholesale electric prices in the West since January 1, 2000, resulting in potentially unjust and unreasonable rates in long-term power sales contracts subsequently entered into by sellers in the West." On May 8, 2002, we received data requests from the FERC related to a disclosure by Enron of certain trading practices in which it may have been engaged in the California market. On May 21, and May 22, 2002, the FERC supplemented the request inquiring as to "wash" or "round-trip" transactions. We responded on May 22, 2002, May 31, 2002, and June 5, 2002, to the data requests. On June 4, 2002, the FERC issued an order to us to show cause why our market-based rate authority should not be revoked as the FERC found that certain of our responses related to the Enron trading practices constituted a failure to cooperate with the staff's investigation. We subsequently supplemented our responses to address the show cause order. On July 26, 2002, we received a letter from the FERC informing us that it had reviewed all of our supplemental responses and concluded that we responded to the initial May 8, 2002 request.

As also discussed below in REPORTING OF NATURAL GAS-RELATED INFORMATION TO TRADE PUBLICATIONS, on November 8, 2002, we received a subpoena from a federal grand jury in Northern California seeking documents related to our involvement in California markets. We are in the process of completing our response to the subpoena. This subpoena is a part of the broad United States Department of Justice (DOJ) investigation regarding gas and power trading.

Pursuant to an order from the Ninth Circuit, the FERC permitted certain California parties to conduct additional discovery into market manipulation by sellers in the California markets. The California parties sought this discovery in order to potentially expand the scope of the refunds. On March 3, 2003, the California parties submitted evidence from this discovery on market manipulation ("March 3rd Report"). We and other sellers submitted comments regarding the additional evidence on March 20, 2003.

On March 26, 2003, the FERC issued a Staff Report addressing: (1) Enron trading practices, (2) an allegation in a June 2, 2002 New York Times article that we had attempted to corner the gas market, and (3) the allegations of gas price index manipulation which are discussed in more detail below in REPORTING OF NATURAL GAS-RELATED INFORMATION TO TRADE PUBLICATIONS. The Staff Report cleared us on the issue of cornering the market and contemplated or established further proceedings on the other two issues as to us and numerous other market participants. On June 25, 2003, the FERC issued a series of orders in response to the California parties' March 3rd Report and the Staff Report. These orders resulted in further investigations regarding potential allegations of physical withholding, economic withholding, and a show cause order alleging that various companies engaged in Enron trading practices. On August 29, 2003, we entered into a settlement with the FERC trial staff of all Enron trading practices for approximately $45,000. The settlement was approved by the FERC on January 22, 2004. The investigations of physical and economic withholding are also continuing. Each of these FERC investigations of alleged market manipulation will be resolved pursuant to the Utility Settlement that is discussed above in Refund proceedings if that settlement is approved by the FERC.

Long-term contracts

In February 2001, during the height of the California energy crisis, we entered into a long-term power contract with the State of California to assist in stabilizing its market. This contract was later challenged by the State of California. This challenge resulted in settlement discussions being held between the State and us on the contract issue as well as other state initiated proceedings and allegations on market manipulation. A settlement was reached that resulted in us entering into a settlement agreement with the State of California and other non-Federal parties that includes renegotiated long-term energy contracts. These contracts are made up of block energy sales, dispatchable products and a gas contract. The settlement does not extend to criminal matters or matters of willful fraud, but also resolved civil complaints brought by the California Attorney General against us and the State of California's refund claims that are discussed above. In addition, the settlement resolved ongoing investigations by the States of California, Oregon and Washington. The settlement was reduced to writing and executed on November 11, 2002. The settlement closed on December 31, 2002, after FERC issued an order granting our motion for partial dismissal from the refund proceedings. The dismissal affects our refund obligations to the settling parties, but not to other parties, such as investor-owned utilities. Pursuant to the settlement, the California Public Utilities Commission (CPUC) and California Electricity Oversight Board (CEOB) filed a motion on January 13, 2003 to withdraw their complaints against us regarding the original block energy sales contract. On June 26, 2003, the FERC granted the CPUC and CEOB joint motion to withdraw their respective complaints against us. Certain private class action and other civil plaintiffs who have initiated class action litigation against us and others in California based on allegations against us with respect to the California energy crisis also executed the settlement. Final approval by the court is needed to make the settlement effective as to plaintiffs and to terminate the class actions as to us. On October 24, 2003, the court granted a motion for preliminary approval of the settlement. The final approval hearing is currently scheduled for June 4, 2004. Upon approval, the majority of civil litigation involving us and California markets will be resolved. Some litigation by non-California plaintiffs, or relating to reporting of natural gas information to trade publications, as discussed below, will continue. As of March 31, 2004, pursuant to the terms of the settlement, we have transferred ownership of six LM6000 gas powered electric turbines, have made two payments totaling $72 million to the California Attorney General, and have funded a $15 million fee and expense fund associated with civil actions that are subject to the settlement. An additional $75 million remains to be paid to the California Attorney General (or his designee) over the next six years, with the final payment of $15 million due on January 1, 2010.

REPORTING OF NATURAL GAS-RELATED INFORMATION TO TRADE PUBLICATIONS

We disclosed on October 25, 2002, that certain of our natural gas traders had reported inaccurate information to a trade publication that published gas price indices. As noted above, on November 8, 2002, we received a subpoena from a federal grand jury in Northern California seeking documents related to our involvement in California markets, including our reporting to trade publications for both gas and power transactions. We are in the process of completing our response to the subpoena. The DOJ's investigation into this matter is continuing. In addition, the Commodity Futures Trading Commission (CFTC) has conducted an investigation of us regarding this issue. On July 29, 2003, we reached a settlement with the CFTC where in exchange for $20 million, the CFTC closed its investigation and we did not admit or deny allegations that we had engaged in false reporting or attempted manipulation. Civil suits based on allegations of manipulating the gas indices have been brought against us and others in federal and state court in California and in Federal court in New York.

MOBILE BAY EXPANSION

On December 3, 2002, an administrative law judge at the FERC issued an initial decision in Transco's 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. The administrative law judge's initial decision is subject to review by the FERC. On March 26, 2004, the FERC issued an Order on Initial Decision in which it reversed the administrative law judge's holding and accepted Transco's proposal for rolled in rates. Power holds long-term transportation capacity on the Mobile Bay expansion project. Had the FERC adopted the decision of the administrative law judge on the pricing of the Mobile Bay expansion project and also required that the decision be implemented effective September 1, 2001, Power could have been subject to surcharges of approximately $46 million, excluding interest, through March 31, 2004, in addition to increased costs going forward. On April 26, 2004, several parties, including Transco filed requests for rehearing of the FERC's March 26, 2004 order.

ENRON BANKRUPTCY

We have outstanding claims against Enron Corp. and various of its subsidiaries (collectively "Enron") related to Enron's bankruptcy filed in December 2001. In March 2002, we sold $100 million of our claims against Enron to a third party for $24.5 million. On December 23, 2003, Enron filed objections to these claims. Under the sales agreement, the purchaser of the claims may demand repayment of the purchase price, plus interest assessed at 7.5 percent per annum, for that portion of the claims still subject to objections 90 days following the initial objection. To date, the purchaser has not demanded repayment.

ENVIRONMENTAL MATTERS

Continuing operations

Since 1989, Transco has had studies under way 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 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 U.S. Environmental Protection Agency (EPA) and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other programs 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, 2004, Transco had accrued liabilities of $28 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances.

We also accrued environmental remediation costs for our natural gas gathering and processing facilities, primarily related to soil and groundwater contamination. At March 31, 2004, we had accrued liabilities totaling approximately $11 million for these costs.

Actual costs incurred for these matters will depend on the actual number of contaminated sites identified, the amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors.

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.

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, 2004, we had accrued liabilities of approximately $10 million for such excess costs.

WILLIAMS ENERGY PARTNERS

As part of our June 17, 2003 sale of Williams Energy Partners (see Note 5), we indemnified the purchaser for:

(1) environmental cleanup costs resulting from certain conditions, primarily soil and groundwater contamination, at specified locations, to the extent such costs exceed a specified amount and

(2) currently unidentified environmental contamination relating to operations prior to April 2002 and identified prior to April 2008.

At March 31, 2004, we had accrued liabilities totaling approximately $9 million for these costs. In addition, we deferred approximately $113 million of the gain associated with our indemnifications, including environmental indemnifications, of the purchaser under the sales agreement. At March 31, 2004, we had a remaining deferred gain relating to this sale of approximately $95 million. When claims for performance under the indemnity for environmental matters are submitted by the purchaser and accepted by us, indemnification amounts for accepted claims are reclassified from the deferred gain to accrued liabilities. We anticipate ongoing performance under the indemnity provisions for environmental claims, and therefore, the amount of ultimate gain cannot be determined.

During the first quarter of 2004, we have been engaged in discussions with the purchaser regarding a potential buyout of these indemnities in the form of a structured cash settlement. At the time of this filing, the discussions are in the advanced stages and it is reasonably possible that an agreement as to terms will be reached during the second quarter. If the agreement is completed as being discussed, we would reclassify a significant portion of the deferred gain to accrued liabilities in the second quarter.

On July 2, 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from our pipelines, pipeline systems, and pipeline facilities used in the movement of oil or petroleum products, during the period from July 1, 1998 through July 2, 2001. In November 2001, we furnished our response. This matter has not become an enforcement proceeding. On March 11, 2004, the Department of Justice (DOJ) invited the new owner of the Williams Pipe Line, Magellan Midstream Partners, L.P. (Magellan), to enter into negotiations regarding alleged violations of the Clean Water Act and to sign a tolling agreement. No penalty has been assessed by the EPA; however, the DOJ stated in its letter that the maximum possible penalties were approximately $22 million for the alleged violations. It is anticipated that by providing additional clarification and through negotiations with the EPA and DOJ, that any proposed penalty will be reduced. We have indemnity obligations to Magellan related to this matter.

OTHER

At March 31, 2004, we had accrued environmental liabilities totaling approximately $13 million related to our:

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

- former propane marketing operations, petroleum products and natural gas pipelines, natural gas liquids fractionation;

- a discontinued petroleum refining facility;

- exploration and production and mining operations; and

- the discontinued Canadian straddle plants.

These costs include (1) certain conditions at specified locations related primarily to soil and groundwater contamination and (2) any penalty assessed on Williams Refining & Marketing, LLC (Williams Refining) associated with noncompliance with EPA's benzene waste "NESHAP" regulations. In 2002, Williams Refining submitted to the EPA a self-disclosure letter indicating noncompliance with those regulations. This unintentional noncompliance had occurred due to a regulatory interpretation that resulted in under-counting the total annual benzene level at Williams Refining's Memphis refinery. Also in 2002, the EPA conducted an all-media audit of the Memphis refinery. The EPA anticipates releasing a report of its audit findings in 2004. The EPA will likely assess a penalty on Williams Refining due to the benzene waste NESHAP issue, but the amount of any such penalty is not known. In connection with the sale of the Memphis refinery in March 2003, we indemnified the purchaser for any such penalty.

Certain of our subsidiaries have been identified as potentially responsible parties (PRP) 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.

OTHER LEGAL MATTERS

Royalty indemnifications

In connection with agreements 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 which the producers may be required to pay as a result of such settlements. Transco, through its agent, Power, 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 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.

As a result of these settlements, Transco has been sued by certain producers seeking indemnification from Transco. Transco is currently a defendant in one lawsuit in which a producer has asserted damages, including interest calculated through March 31, 2004, of approximately $10 million. On July 11, 2003, at the conclusion of the trial, the judge ruled in Transco's favor and subsequently entered a formal judgment. The plaintiff is seeking an appeal.

Will Price (formerly Quinque)

On June 8, 2001, fourteen of our entities were named as defendants in a nationwide class action lawsuit which had been pending against other defendants, generally pipeline and gathering companies, for more than one year. The plaintiffs allege that the defendants, including us, 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. After the court denied class action certification and while motions to dismiss for lack of personal jurisdiction were pending, the court granted the plaintiffs' motion to amend their petition on July 29, 2003. The fourth amended petition, which was filed on July 29, 2003, deletes all of our defendants except two Midstream subsidiaries. All defendants intend to continue their opposition to class certification.

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 sale of Kern River and Texas Gas, 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. The amounts accrued for these indemnifications are insignificant. Grynberg has 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. On April 9, 1999, the DOJ announced that it was declining to intervene in any of the Grynberg qui tam cases, including the action filed in federal court in Colorado against us. On October 21, 1999, the Panel on Multi-District Litigation transferred all of the Grynberg qui tam cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. Grynberg's measurement claims remain pending against us and the other defendants; the court previously dismissed Grynberg's royalty valuation claims.

On August 6, 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 Williams Production RMT Company with a complaint in the state court in Denver, Colorado. The complaint alleges that the defendants have used mismeasurement techniques that distort the BTU 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 defendants inappropriately took deductions from the gross value of their natural gas and made other royalty valuation errors. Theories for relief include breach of contract, breach of implied covenant of good faith and fair dealing, anticipatory repudiation, declaratory relief, equitable accounting, civil theft, deceptive trade practices, negligent misrepresentation, deceit based on fraud, conversion, breach of fiduciary duty, and violations of the state racketeering statute. 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 $1.4 million dollars. Our motion to stay the proceedings in this case based on the pendency of the False Claims Act litigation discussed in the preceding paragraph was granted on January 15, 2003.

Securities class actions

Numerous shareholder class action suits have been filed against us in the United States District Court for the Northern District of Oklahoma. The majority of the suits allege that we and co-defendants, WilTel Communications (WilTel), previously an owned subsidiary known as Williams Communications, and certain corporate officers, have acted jointly and separately to inflate the stock price of both companies. Other suits allege similar causes of action related to a public offering in early January 2002, known as the FELINE PACS offering. These cases were filed against us, certain corporate officers, all members of our Board of Directors and all of the offerings' underwriters. These cases have all been consolidated and an order has been issued requiring separate amended consolidated complaints by our equity holders and WilTel equity holders. The underwriters of this offering have requested indemnification from these cases. If granted, costs incurred as a result of these indemnifications will not be covered by our insurance policies. The amended complaint of the WilTel securities holders was filed on September 27, 2002, and the amended complaint of our securities holders was filed on October 7, 2002. This amendment added numerous claims related to Power. In addition, four class action complaints have been filed against us, the members of our Board of Directors and members of our Benefits and Investment Committees under the Employee Retirement Income Security Act (ERISA) by participants in our 401(k) plan. A motion to consolidate these suits has been approved. On July 14, 2003, the Court dismissed us and our Board from the ERISA suits, but not the members of the Benefits and Investment Committees to whom we might have an indemnity obligation. If it is determined that we have an indemnity obligation, we expect that any costs incurred will be covered by our insurance policies. The Department of Labor is also independently investigating our employee benefit plans. On December 15, 2003, the court substantially denied the defendants' motion to dismiss in the shareholder suits. On April 2, 2004, the purported class of our securities holders filed a partial motion for summary judgment with respect to certain disclosures made in connection with our public offerings during the class period. Derivative shareholder suits have been filed in state court in Oklahoma, all based on similar allegations. On August 1, 2002, a motion to consolidate and a motion to stay these Oklahoma suits pending action by the federal court in the shareholder suits was approved.

Oklahoma securities investigation

On April 26, 2002, the Oklahoma Department of Securities issued an order initiating an investigation of us and WilTel regarding issues associated with the spin-off of WilTel and regarding the WilTel bankruptcy. We have no pending inquiries in this investigation, but are committed to cooperate fully in the investigation.

Shell offshore litigation

On November 30, 2001, Shell Offshore, Inc. filed a complaint at the FERC against Williams Gas Processing - Gulf Coast Company, L.P. (WGP), Williams Gulf Coast Gathering Company (WGCGC), Williams Field Services Company (WFS) and Transco, alleging concerted actions by the affiliates frustrating the FERC's regulation of Transco. The alleged actions are related to offers of gathering service by WFS and its subsidiaries on the deregulated North Padre Island offshore gathering system. On September 5, 2002, the FERC issued an order reasserting jurisdiction over that portion of the North Padre Island facilities previously transferred to WFS. The FERC also determined an unbundled gathering rate for service on these facilities which is to be collected by Transco. Transco, WGP, WGCGC and WFS believe their actions were reasonable and lawful and each have filed petitions for review of the FERC's orders with the U.S. Court of Appeals for the District of Columbia.

TAPS Quality Bank

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. Primary issues being litigated include the appropriate valuation of the naphtha, heavy distillate, vacuum gas oil and residual product cuts within the TAPS Quality Bank as well as the appropriate retroactive effects of the determinations. WAPI's interest in these proceedings is material as the matter involves claims by crude producers and the State of Alaska for retroactive payments plus interest of up to $180 million. Due to the sale of WAPI's interests on March 31, 2004, no future Quality Bank liability will accrue. Because of the complexity of the issues involved, however, the outcome cannot be predicted with certainty nor can the likely result be quantified. Certain periodic discussions have been held and continue among some of the litigants. Because of the number of parties involved and the diversity of positions, no comprehensive terms have been identified that could be considered probable to achieve final settlement among all parties. The FERC and RCA presiding administrative law judges are expected to render their joint and/or individual initial decision(s) sometime during the third quarter of 2004. Although we sold WAPI, we retained potential liability for any retroactive payments that may be awarded in these proceedings for the period ending on March 31, 2004.

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. At March 31, 2004, 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 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 coverage, recovery from customers or other indemnification arrangements, will not have a materially adverse effect upon our future financial position.

COMMITMENTS

Power has entered into certain contracts giving it the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are currently in operation throughout the continental United States. At March 31, 2004, Power's estimated committed payments under these contracts are approximately $307 million for the remainder of 2004, range from approximately $397 million to $423 million annually through 2017 and decline over the remaining five years to $58 million in 2022. Total committed payments under these contracts over the next eighteen years are approximately $6.6 billion.

GUARANTEES

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 exceed the minimum purchase price.

In connection with the construction of a joint venture pipeline project, we guaranteed, through a put agreement, certain portions of the joint venture's project financing in the event of nonpayment by the joint venture. Our potential liability under this guarantee ranges from zero percent to 100 percent of the outstanding project financing, depending on our ability and the other project members' ability to meet certain performance criteria. As of March 31, 2004, the total outstanding project financing is $32.4 million. Our maximum potential liability is the full amount of the financing, but based on the current status of the project, it is likely that any obligation would be limited to 50 percent of the outstanding financing. As additional borrowings are made under the project financing facility, our potential exposure will increase. This guarantee expires in March 2005, and we have not accrued any amounts at March 31, 2004.

We have guaranteed commercial letters of credit totaling $17 million on behalf of Accroven. These expire in January 2005, have no carrying value and are fully collateralized with cash.

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 and have a maximum potential exposure of approximately $51 million at March 31, 2004. Our exposure declines systematically throughout the remaining term of WilTel's obligations. The carrying value of these guarantees is approximately $46 million at March 31, 2004 and is recorded as a non-current liability.

We have provided guarantees on behalf of certain partnerships in which we have an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. These guarantees continue until we withdraw from the partnerships. No amounts have been accrued at March 31, 2004.

12. COMPREHENSIVE INCOME (LOSS)

Comprehensive income (loss) from both continuing and discontinued operations is as follows:

	THREE MONTHS ENDED MARCH 31, 2004	2003
	(MILLIONS)	
Net income (loss)	$ 9.9	$ (814.5)
Other comprehensive income (loss):		
Unrealized losses on securities	-	(4.2)
Net realized losses on securities	3.0	-
Unrealized losses on derivative instruments	(184.6)	(184.1)
Net reclassification into earnings of derivative instrument losses	46.7	15.3
Foreign currency translation adjustments	(5.3)	24.7
Minimum pension liability adjustment	.7	-
Other comprehensive loss before taxes	(139.5)	(148.3)
Income tax benefit on other comprehensive loss	51.4	66.2
Other comprehensive loss	(88.1)	(82.1)
Comprehensive loss	$ (78.2)	$ (896.6)

13. SEGMENT DISCLOSURES

Segments and reclassification of operations

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. Other primarily consists of corporate operations and certain continuing operations previously reported within the International and Petroleum Services segments.

Since May 1995, an entity within our Midstream segment has operated production area facilities owned by entities within our Gas Pipeline segment. These regulated gas gathering assets have been operated pursuant to the terms of an operating agreement. Effective June 1, 2004, and due in part to FERC Order 2004, the operating agreement was terminated and management and decision-making control transferred to the Gas Pipeline segment. Consequently, the results of operations were similarly reclassified. All prior periods reflect these classifications.

Effective September 21, 2004, and due in large part to FERC Order 2004, management and decision-making control of our equity method investment in the Aux Sable gas processing plant and related business was transferred from our Midstream segment to our Power segment. Consequently, the results of operations were similarly reclassified. All prior periods reflect these classifications.

Segments - performance measurement

We currently evaluate performance based upon segment profit (loss) from operations which, includes revenues from external and internal customers, operating costs and expenses, depreciation, depletion and amortization, equity earnings (losses) and income (loss) from investments including gains/losses on 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.

Power has entered into intercompany interest rate swaps with the corporate parent, the effect of which is included in Power's segment revenues and segment profit (loss) as shown in the reconciliation within the following tables. The results of interest rate swaps with external counterparties are shown as interest rate swap income (loss) in the Consolidated Statement of Operations below operating income.

The majority of energy commodity hedging by certain of our business units is done through intercompany derivatives with Power which, in turn, enters into offsetting derivative contracts with unrelated third parties. Power bears the counterparty performance risks associated with unrelated third parties.

The following tables reflect the reconciliation of revenues and operating income (loss) as reported in the Consolidated Statement of Operations to segment revenues and segment profit (loss).

Notes (Continued)

13. SEGMENT DISCLOSURES (CONTINUED)

	POWER	GAS PIPELINE	EXPLORATION & PRODUCTION	MIDSTREAM GAS & LIQUIDS	OTHER	ELIMINATIONS	TOTAL
				(MILLIONS)			
THREE MONTHS ENDED MARCH 31, 2004							
Segment revenues:							
External	$ 2,103.9	$ 355.3	$ (14.8)	$ 618.3	$ 2.8	$ -	$ 3,065.5
Internal	170.9	3.7	180.0	9.0	9.8	(373.4)	-
Total segment revenues	2,274.8	359.0	165.2	627.3	12.6	(373.4)	3,065.5
Less intercompany interest rate swap loss	(21.6)	-	-	-	-	21.6	-
Total revenues	$ 2,296.4	$ 359.0	$ 165.2	$ 627.3	$ 12.6	$ (395.0)	$ 3,065.5
Segment profit (loss)	$ (32.0)	$ 147.4	$ 51.5	$ 107.6	$ (8.7)	$ -	$ 265.8
Less:							
Equity earnings	.7	3.8	2.9	4.2	-	-	11.6
Loss from investments	-	(.3)	-	(.2)	(6.5)	-	(7.0)
Intercompany interest rate swap loss	(21.6)	-	-	-	-	-	(21.6)
Segment operating income (loss)	$ (11.1)	$ 143.9	$ 48.6	$ 103.6	$ (2.2)	$ -	282.8
General corporate expenses							(32.0)
Consolidated operating income							$ 250.8
THREE MONTHS ENDED MARCH 31, 2003							
Segment revenues:							
External	$ 3,588.0	$ 332.8	$ (7.1)	$ 847.9	$ 14.5	$ -	$ 4,776.1
Internal	187.6	6.8	251.0	17.5	13.5	(476.4)	-
Total segment revenues	3,775.6	339.6	243.9	865.4	28.0	(476.4)	4,776.1
Less intercompany interest rate swap loss	(5.9)	-	-	-	-	5.9	-
Total revenues	$ 3,781.5	$ 339.6	$ 243.9	$ 865.4	$ 28.0	$ (482.3)	$ 4,776.1
Segment profit (loss)	$ (137.0)	$ 150.3	$ 113.8	$ 112.8	$ 4.8	$ -	$ 244.7
Less:							
Equity earnings (loss)	(.6)	1.8	2.1	(2.6)	3.7	-	4.4
Intercompany interest rate swap loss	(5.9)	-	-	-	-	-	(5.9)
Segment operating income (loss)	$ (130.5)	$ 148.5	$ 111.7	$ 115.4	$ 1.1	$ -	246.2
General corporate expenses							(22.9)
Consolidated operating income							$ 223.3

	TOTAL ASSETS	
	MARCH 31, 2004	DECEMBER 31, 2003
	(MILLIONS)	
Power	$ 10,197.7	$ 8,732.9
Gas Pipeline	7,312.6	7,314.3
Exploration & Production	5,372.5	5,347.4
Midstream Gas & Liquids	4,021.1	3,990.3
Other	5,700.2	6,928.7
Eliminations	(5,323.1)	(6,078.2)
	27,281.0	26,235.4
Discontinued operations	509.2	786.4
Total	$ 27,790.2	$ 27,021.8

14. RECENT ACCOUNTING STANDARDS

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, the SEC staff, in a letter to the EITF Chairman, questioned whether leased mineral rights should be presented as intangible assets rather than property, plant and equipment. In March 2004, the EITF reached a consensus that all mineral rights should be considered tangible assets for accounting purposes. Therefore, no reclassification will be required.

15. SUBSEQUENT EVENTS

NOTES PAYABLE AND LONG-TERM DEBT

In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of a specified series of our outstanding notes and debentures. As of the June 8, 2004, tender offer expiration date, we had accepted for purchase tenders of notes and debentures with an aggregate principal amount of approximately $1.17 billion. In May 2004, we also repurchased approximately $255 million of various notes with maturity dates ranging from 2006 to 2011. In conjunction with these tendered notes and debentures and related consents, and early retirements, we paid premiums of approximately $79 million.

In August 2004, we expanded our three-year, $1 billion secured revolving credit facility by an additional $275 million.

Upon entering into the new $1 billion secured revolving credit facility on May 3, 2004 (see Note 10), we terminated the $800 million revolving and letter of credit facility which we entered into in June 2003.

In August 2004, we made cash tender offers and consent solicitations for all of our 8.625 percent senior notes due 2010. Approximately $792.8 million, or approximately 99 percent, aggregate principal amount of notes were accepted for purchase. In conjunction with this purchase, we paid premiums of approximately $135 million.

On September 17, 2004, we initiated an offer to exchange up to 43.9 million FELINE PACS units for one share of our common stock plus $1.47 in cash for each unit. The offer expired October 18, 2004 and resulted in approximately 33.1 million of the 44 million issued and outstanding units being tendered and accepted for exchange. The exchange offer reduced our overall debt by approximately $827 million and increased our common stock outstanding by 33.1 million shares. The effect of the exchange, including a pre-tax charge for related expenses of approximately $25 million, will be reflected in the fourth quarter.

ENVIRONMENTAL MATTERS

As part of our June 17, 2003 sale of Williams Energy Partners (see Note 2), we indemnified the purchaser for:

(1) environmental cleanup costs resulting from certain conditions, primarily soil and groundwater contamination, at specified locations, to the extent such costs exceed a specified amount and

(2) currently unidentified environmental contamination relating to operations prior to April 2002 and identified prior to April 2008.

On May 26, 2004, the parties reached an agreement for buyout of certain indemnities in the form of a structured cash settlement totaling $117.5 million. Yearly payments will be made through 2007. The agreement releases Williams from all environmental indemnity obligations under the June 2003 Sale of Williams Energy Partners and two related agreements. Williams is now indemnified by the purchaser for third party environmental claims made against Williams for claims covered under the June 2003 purchase and sale agreement (PSA) and related agreements as well as all environmental occurrences before the closing date of the PSA. The agreement also transferred most third party litigation matters related to Williams Energy Partners' assets to the purchaser.

ASSET SALES

On July 28, 2004, we closed the sale of the Canadian straddle plants for approximately $544 million in U.S. funds, including amounts paid to our subsidiaries for amounts previously due from the straddle plants. We expect to recognize a pre-tax gain of approximately $190 million on the sale in third-quarter 2004.

OTHER LEGAL MATTERS

As discussed in Note 11, 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. Primary issues being litigated include the appropriate valuation of the naptha, heavy distillate, vacuum gas oil and residual product cuts within the TAPS Quality Bank as well as the appropriate retroactive effects of the determinations.

The FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions during the third quarter of 2004. The initial decisions set forth methodologies for determining the valuations of the product cuts under review and also approved the retroactive application of the approved methodologies for the heavy distillate and residual product cuts. Based on our computation and assessment of ultimate ruling terms that would be considered probable, we recorded an accrual of approximately $134 million in the third quarter of 2004. Because the application of certain aspects of the initial decisions are subject to interpretation, we have calculated the reasonably possible impact of the decisions, if fully adopted by the FERC and RCA, to result in additional exposure to us of approximately $32 million more than we have accrued at September 30, 2004. We will be filing a brief on exceptions to the initial decisions to both the FERC and RCA on November 16, 2004, and reply briefs are due on February 1, 2005. Decisions from the Commissions will then be issued likely before the end of 2005. It is unlikely that we will be required to make any payments with respect to this matter until sometime after the Commission decisions.

Winterthur International Insurance Company (Winterthur) issued policies to Gulf Liquids providing financial assurance related to construction contracts among Gulf Liquids, Gulsby Engineering, Inc. and Gulsby-Bay. After disputes arose regarding obligations under the construction contracts, Winterthur disputed coverage resulting in arbitration between Winterthur and Gulf Liquids. In July 2004, the arbitration panel awarded Gulf Liquids $93.6 million, offset by $18 million previously paid to Gulf Liquids, plus interest of $7.7 million, for a total award to Gulf Liquids of approximately $83.3 million. Winterthur has filed a Petition to Vacate the Arbitration Award in the New York State court. On November 1, 2004, Winterthur remitted approximately $85 million to us in the settlement of certain disputes regarding obligations under construction contracts. As a result of the payment, we will recognize pre-tax income of approximately $95 to $100 million within Income from discontinued operations in the fourth quarter.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

RECENT EVENTS AND COMPANY OUTLOOK

In February 2003, we outlined our planned business strategy in response to the events that significantly impacted the energy sector and our company during late 2001 and much of 2002, including the collapse of Enron and the severe decline of the telecommunications industry. The plan focused on migrating to an integrated natural gas business comprised of a strong, but smaller, portfolio of natural gas businesses; reducing debt; and increasing our liquidity through asset sales, strategic levels of financing and reductions in operating costs. The plan was designed to address near-term and medium-term debt and liquidity issues, to de-leverage the company with the objective of returning to investment grade status and to develop a balance sheet and cash flows capable of supporting and ultimately growing our remaining businesses.

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, we successfully executed certain critical components of our plan during 2003. Key execution steps for 2004 and beyond include the following:

- completion of planned asset sales, which are estimated to generate proceeds of approximately $800 million in 2004;
- additional reductions of our SG&A costs;
- the replacement of our cash-collateralized letter of credit and revolver facility with facilities that do not encumber cash; and
- continuation of our efforts to exit from the Power business.

Projected asset sales in 2004 include the Alaska refinery and certain assets of our Midstream segment including the straddle plants in western Canada. On March 31, 2004, we completed the sale of our Alaska refinery and related assets for approximately $304 million (see Note 5 of Notes to Consolidated Financial Statements).

In April 2004, we entered into two new unsecured credit facilities totaling $500 million, primarily for the purpose of issuing letters of credit. During April 2004, use of these facilities released approximately $500 million of restricted cash, restricted investments and margin deposits. Also, on May 3, 2004, we entered into a new three-year, $1 billion secured revolving credit facility. The revolving facility is secured by certain Midstream assets and a guarantee from WGP (see Note 10 of Notes to Consolidated Financial statements).

As part of our planned strategy, on February 25, 2004, our Exploration & Production segment amended its $500 million secured note facility, which was originally due May 30, 2007. The amendment provided more favorable terms including a lower interest rate and an extension of the maturity by one year (see Note 10 of Notes to Consolidated Financial Statements).

On March 15, 2004, we retired $679 million of senior unsecured 9.25 percent notes due March 15, 2004. The amount represented the outstanding balance subsequent to the fourth-quarter 2003 tender which retired $721 million of the original $1.4 billion balance. Long-term debt, excluding the current portion, at March 31, 2004 was approximately $10.8 billion.

POWER BUSINESS STATUS

Since mid-2002, we have been pursuing a strategy of exiting the Power business and have worked with financial advisors to assist with this effort. To date, several factors have contributed to the difficulty of achieving a complete exit from this business, including the following with respect to the wholesale power industry:

- oversupply position in most markets expected through the balance of the decade;
- slow North American gas supply response to high gas prices; and
- expectations of hybrid regulated/deregulated market structure for several years.

As a result of these factors and the size of our Power business, the number of financially viable parties expressing an interest in purchasing the entire business have been limited. Additionally, the current and near term view of the wholesale power market, which we interpret as depressed, has strongly influenced these parties' view of value and related risk associated with this business.

Because market conditions may change, and we cannot determine the impact of this on a buyer's point of view, amounts ultimately received in any portfolio sale, contract liquidation or realization may be significantly different from the estimated economic value or carrying values reflected in the Consolidated Balance Sheet. In addition, our tolling agreements are not derivatives and thus have no carrying value in the Consolidated Balance Sheet pursuant to the application of EITF 02-3. Based on current market conditions, certain of these agreements are forecasted to realize significant future losses. It is possible that we may sell contracts for less than their carrying value or enter into agreements to terminate certain obligations, either of which could result in significant future loss recognition or reductions of future cash flows.

We continue to evaluate alternatives and discuss our plans and operating strategy for the Power business with our Board of Directors. As an alternative to continuing a plan of pursuing a complete exit from the Power business, we are evaluating whether the benefits of realizing the positive cash flows expected to be generated by this business through continued ownership exceed the benefits of a sale at a depressed price. If we pursue this alternative, we expect to continue our current program of managing this business to minimize financial risk, generate cash and manage existing contractual commitments.

GENERAL

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standard (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the consolidated financial statements and notes in Item 1 [Exhibit 99.3] reflect the results of operations, financial position and cash flows through the date of sale, as applicable, of the following components as discontinued operations (see Note 5 of Notes to Consolidated Financial Statements):

- retail travel centers concentrated in the Midsouth, part of the previously reported Petroleum Services segment;
- refining and marketing operations in the Midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;
- Texas Gas Transmission Corporation, previously one of Gas Pipeline's segments;
- natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment;
- bio-energy operations, part of the previously reported Petroleum Services segment;
- our general partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;
- the Colorado soda ash mining operations, part of the previously reported International segment;
- certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream segment;
- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment;
- Gulf Liquids New River Project LLC, previously part of the Midstream segment; and
- our straddle plants in western Canada, previously part of the Midstream segment.

Effective June 1, 2004, and due in part to FERC Order 2004, management and decision - making control of certain regulated gas gathering assets was transferred from our Midstream segment to our Gas Pipeline segment. Consequently, the results of operations were similarly reclassified. All prior periods reflect these classifications.

Unless indicated otherwise, the following discussion and analysis of results of operations, financial condition and liquidity relates to our current continuing operations and should be read in conjunction with the consolidated financial statements and notes thereto included in Item 1 [Exhibit 99.3] of this document and our 2003 Annual Report on Form 10-K, as restated and amended.

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, 2004. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	THREE MONTHS ENDED MARCH 31,		
	2004	2003	% CHANGE FROM 2003 (1)
		(MILLIONS)	
Revenues	$ 3,065.5	$ 4,776.1	-36%
Costs and expenses:			
Costs and operating expenses	2,689.9	4,423.6	+39%
Selling, general and administrative expenses	84.4	105.6	+20%
Other expense - net	8.4	.7	NM
General corporate expenses	32.0	22.9	-40%
Total costs and expenses	2,814.7	4,552.8	+38%
Operating income	250.8	223.3	+12%
Interest accrued - net	(239.3)	(340.9)	+30%
Interest rate swap loss	(8.1)	(2.8)	-189%
Investing income	10.3	46.3	-78%
Minority interest in income of consolidated subsidiaries	(4.8)	(3.5)	-37%
Other income - net	.9	22.1	-96%
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	9.8	(55.5)	NM
Provision (benefit) for income taxes	11.3	(12.4)	NM
Loss from continuing operations	(1.5)	(43.1)	+97%
Income (loss) from discontinued operations	11.4	(10.1)	NM
Income (loss) before cumulative effect of change in accounting principles	9.9	(53.2)	NM
Cumulative effect of change in accounting principles	-	(761.3)	NM
Net income (loss)	9.9	(814.5)	NM
Preferred stock dividends	-	6.8	NM
Income (loss) applicable to common stock	$ 9.9	$ (821.3)	NM

(1) + = Favorable Change; - = Unfavorable Change; 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, 2004 vs. Three Months Ended March 31, 2003

Our revenues decreased $1,710.6 million due primarily to decreased revenues at our Power segment, our Midstream segment, and our Exploration & Production segment. Power revenues decreased approximately $1.5 billion due primarily to lower power, natural gas and crude and refined products sales volumes. Midstream's revenues decreased $238.1 million due primarily to the sale of our wholesale propane business in fourth-quarter 2003, which resulted in lower product sales for natural gas liquids trading activities. In addition, Exploration & Production's revenues decreased $78.7 million due primarily to lower production revenues from lower net realized average prices and lower production volumes as a result of property sales.

Costs and operating expenses decreased $1,733.7 million due primarily to decreased costs and operating expenses at Power and Midstream. The decrease at Power is due primarily to lower power, natural gas and crude and refined products purchase volumes. The decrease at Midstream is due primarily to the 2003 sale of our wholesale propane business.

Selling, general and administrative expenses decreased $21.2 million. This cost reduction is due primarily to reduced staffing levels at Power, reflective of our strategy to exit this business. Also contributing to the decrease was the absence of $11.8 million of expense related to the accelerated recognition of deferred compensation during 2003.

Other expense - net, within operating income, in 2004 includes $6.1 million in fees related to the sale of PG&E receivables to Bear Stearns.

General corporate expenses increased $9.1 million due primarily to increased third-party costs associated with the implementation of the Sarbanes-Oxley Act of 2002 and with efforts to evaluate and implement certain cost reduction strategies through internal initiatives and the potential outsourcing of certain services.

Interest accrued - net decreased $101.6 million due primarily to:

- $89.4 million lower interest expense and fees related to the RMT note payable, which was prepaid in May 2003 and partially refinanced at market rates;
- $10.3 million lower amortization expense related to deferred debt issuance costs, primarily due to the reduction of debt;
- a $3 million decrease reflecting lower average borrowing levels;
- a $6 million decrease reflecting lower average interest rates on long-term debt; and
- a $7.9 million decrease in capitalized interest, which offsets interest accrued, due primarily to completion of certain Midstream projects in the Gulf Coast Region.

We entered into interest rate swaps with external counterparties primarily in support of the energy-trading portfolio (see Note 13 of Notes to Consolidated Financial Statements). The change in market value of these swaps was $5.3 million less favorable in 2004 than 2003. The total notional amount of these swaps was approximately $300 million at March 31, 2004 and March 31, 2003.

Investing income decreased $36 million due primarily to:

- $39.4 million lower interest income at Power as a result of 2003 accrual adjustments associated with certain 2003 FERC proceedings;
- a $12 million impairment of a cost based investment related to Algar Telecom S.A. recognized in 2003;
- $9.2 million higher equity earnings from Discovery Pipeline due primarily to the absence of unfavorable audit adjustments recorded at the partnership in 2003;
- $6.5 million net unreimbursed Longhorn recapitalization advisory fees; and
- $3.6 million of impairments during 2004 of certain international cost-based investments.

Other income - net, below operating income, includes a $2.6 million net gain in 2004 and a $12.5 million net gain in 2003. The net gain in 2004 consists of a $2.5 million foreign currency transaction loss on a Canadian dollar denominated note receivable, more than offset by a $5.1 million derivative gain on a forward contract to fix the U.S. dollar principal cash flows from the note receivable. In 2004, the gain from the forward contract exceeds the foreign currency translation loss from the note as the note balance was substantially reduced in 2003 but the size of the related forward contract was unchanged. The net gain in 2003 consists of a $29.2 million foreign currency transaction gain on the same note, offset by a $16.7 million derivative loss on the forward contract.

The provision (benefit) for income taxes was unfavorable by $23.7 million due primarily to a pre-tax income in 2004 as compared to a pre-tax loss for 2003. The effective income tax rate for 2004 is greater than the federal statutory rate due primarily to an accrual for income tax contingencies, net foreign operations and state income taxes. The effective income tax rate for 2003 is less than the federal statutory rate (less tax benefit) due primarily to an accrual for income tax contingencies and state income taxes.

In addition to the operating results from activities included in discontinued operations (see Note 5 of Notes to Consolidated Financial Statements), the 2004 gain from discontinued operations includes a pre-tax gain of $3.6 million on the sale of the Alaska refinery, retail and pipeline assets and an adjustment to increase the gain on the sale of our 100 percent general partnership interest and 54.6 percent limited partner investment in Williams Energy Partners recorded in June 2003 by $3.3 million. The 2003 loss from discontinued operations includes $117.3 million of pre-tax impairments, offset by a gain on sale as follows:

- a $109 million impairment of Texas Gas Transmission;
- an $8 million impairment of the Alaska refinery, retail and pipeline assets;
- a $5 million impairment of the soda ash mining facility located in Colorado; and
- a $4.7 million gain on the sale of a refinery and other related operations located in Memphis, Tennessee.

The cumulative effect of change in accounting principles reduced net income for 2003 by $761.3 million due to a $762.5 million charge related to the adoption of EITF 02-3, slightly offset by $1.2 million related to the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" (see Note 3 of Notes to Consolidated Financial Statements).

In June 2003, we redeemed all of our outstanding 9.875 percent cumulative-convertible preferred shares.

RESULTS OF OPERATIONS - SEGMENTS

We are currently organized into the following segments: Power, Gas Pipeline, Exploration & Production, Midstream and Other. Other primarily consists of corporate operations and certain continuing operations previously reported within the International and Petroleum Services segments. Our management currently evaluates performance based on segment profit (loss) from operations (see Note 13 of Notes to Consolidated Financial Statements).

Prior period amounts have been restated to reflect these changes. The following discussions relate to the results of operations of our segments.

POWER

OVERVIEW OF THREE MONTHS ENDED MARCH 31, 2004

As described below, the continued effort to exit from the Power business, combined with liquidity constraints, and the effect of price changes on derivative contracts significantly influenced Power's first-quarter 2004 operating results.

In the first quarter of 2004, Power continued to focus on 1) terminating or selling all or portions of the portfolio, 2) maximizing cash flow, 3) reducing risk, and 4) managing existing contractual commitments. These efforts are consistent with our 2002 decision to sell all or portions of Power's power, natural gas, and crude and refined products portfolios. The decrease in revenues, costs and selling, general and administrative expenses reflect our efforts to exit the Power business.

Lack of liquidity in long-term power and natural gas markets also caused a decrease in power revenues and costs. Due to this lack of liquidity, we were not able to replace certain long-term power and natural gas contracts that expired or were terminated in 2003.

Lower interest rates caused losses on derivative contracts, which are reflected as a decrease in revenues. Increased natural gas prices primarily caused an increase in the fair value of gas derivative contracts, which is reflected as an increase in revenues.

Key factors that influence Power's financial condition and operating performance include the following:

- prices of power and natural gas, including changes in the margin between power and natural gas prices;
- changes in market liquidity, including changes in the ability to economically hedge the portfolio;
- changes in power and natural gas price volatility;
- changes in the regulatory environment; and
- changes in power and natural gas supply and demand.

OUTLOOK FOR THE REMAINDER OF 2004

In the remainder of 2004, Power anticipates further variability in earnings due in part to the difference in accounting treatment of derivative contracts at fair value and the underlying non-derivative contracts on an accrual basis. This difference in accounting treatment combined with the volatile nature of energy commodity markets could result in future operating gains or losses. Some of Power's tolling contracts have a negative fair value, which is not reflected in the financial statements since these contracts are not derivatives. These tolling contracts may result in future accrual losses. Continued efforts to sell all or a portion may also have a significant impact on future earnings as proceeds may differ significantly from carrying values. The inability of counterparties to perform under contractual obligations due to their own credit constraints could also affect future operations.

THREE MONTHS ENDED MARCH 31, 2004 VS. THREE MONTHS ENDED MARCH 31, 2003

	THREE MONTHS ENDED MARCH 31,	
	2004	2003
	(MILLIONS)	
Segment revenues................	$ 2,274.8	$ 3,775.6
Segment loss....................	$ (32.0)	$ (137.0)

Revenues

Power's revenues reflect the following:

- gains and losses from changes in fair value of derivative contracts with a future settlement or delivery date;
- revenue from sales of commodities or completion of energy-related services; and
- gains and losses from net financial settlement of derivative contracts.

Power's revenues decreased $1.5 billion, or 40 percent. Of this decrease, $890.2 million represents decreased power and natural gas revenues, $582.7 million represents decreased crude and refined products revenues and $27.9 million represents decreased interest rate portfolio revenues.

A decrease in power and natural gas sales volumes primarily caused the decrease in power and natural gas revenues. Sales volumes decreased because Power did not replace certain long-term physical power and natural gas contracts that expired or were terminated in 2003, primarily due to a lack of market liquidity and efforts to reduce our commitment to the Power business. An increase in net unrealized revenue on natural gas derivatives partially offset the decrease in revenue. The impact of a greater increase in forward natural gas prices in 2004 on certain natural gas positions compared to the prior year caused this increase. In addition, power and natural gas revenues increased due to the absence of unrealized losses of approximately $70 million recorded in 2003 on contracts for which we elected the normal purchases and sales exception in second-quarter 2003. We now account for these contracts on an accrual basis. Finally, power and natural gas revenues in 2003 include a $37 million loss for increased power rate refunds owed to the state of California because of FERC rulings, which also partially offset the decrease in revenues.

Crude and refined products revenues declined from lower sales volumes, reflecting our efforts to exit this line of business. A decrease in purchase volumes largely offset the effect of the decrease in sales volumes.

Revenues reflect a net realized and unrealized loss of $43.5 million on interest rate derivatives in first-quarter 2004 compared to a net realized and unrealized loss of $15.6 million in first-quarter 2003. A greater decrease in interest rates in 2004 compared to the prior year caused this decrease in revenues from our interest rate portfolio.

Costs

Power's costs represent purchases of commodities and fees paid for energy-related services. Power's costs decreased $1.6 billion or 41 percent. Of this decrease, $1.0 billion represents decreased power and natural gas costs and $579.9 million represents decreased crude and refined products costs.

A decrease in power and natural gas purchase volumes primarily contributed to the decrease in power and natural gas costs. Purchase volumes decreased because Power did not replace certain long-term physical power and natural gas contracts that expired or were terminated in 2003. Decreased purchase volumes also caused the decrease in crude and refined products costs. Our efforts to exit this line of business caused the decrease in purchase volumes.

Costs in 2004 reflect a $13 million payment made to terminate a non-derivative power sales contract.

Gross Margin

The gross margin loss of $2 million in first quarter 2004 declined $89.1 million, or 98 percent, from the gross margin loss in 2003. An increase in power and natural gas gross margin of $119.8 million primarily caused this improvement. The following factors, as discussed in the previous two sections, primarily caused the increase in power and natural gas gross margin:

- the increase in net unrealized revenue on natural gas derivatives;

- unrealized losses in 2003 of approximately $70 million on derivative contracts, which we treated on an accrual basis under the normal purchases and sales exception in 2004; and

- the $37 million loss resulting from FERC rulings recognized in 2003.

The $13 million payment made to terminate a non-derivative power sales contract in the first quarter of 2004, as discussed above, partially offsets the increase in power and natural gas gross margin.

A $27.9 million increase in the interest rate portfolio margin loss partially offsets the increase in power and natural gas gross margin. As discussed in the "Revenues" section above, a decrease in the fair value of interest rate derivatives primarily caused this increased interest rate portfolio margin loss.

Selling, General and Administrative Expenses

Selling, general and administrative expenses decreased $20.2 million, or 56 percent, primarily due to staff reductions. Power employed approximately 245 employees at March 31, 2004 compared with approximately 327 at March 31, 2003. The staff reductions coincided with our efforts to exit the Power business.

Segment Profit

Power's segment profit increased $105 million, or 77 percent. An increase in power and natural gas gross margins, partially offset by a decrease in interest rate portfolio gross margin, contributed to the increase in segment profit. A decrease in selling, general and administrative expenses as discussed above also contributed to the increase in segment profit.

GAS PIPELINE

OVERVIEW OF THREE MONTHS ENDED MARCH 31, 2004

In February 2004, Transco placed an expansion into service increasing capacity on its natural gas system by 54,000 Dth/d. As discussed below, Gas Pipeline made additional progress towards repairing and restoring a segment of our natural gas pipelines in western Washington.

OUTLOOK FOR THE REMAINDER OF 2004

In December 2003, we received an Amended Corrective Action Order (ACAO) from the U.S. Department of Transportation's Office of Pipeline Safety (OPS) regarding a segment of one of our natural gas pipelines in western Washington. The pipeline experienced two breaks in 2003 and we subsequently idled the pipeline segment until its integrity could be assured. The decision to idle the pipeline has not had a significant impact on our ability to meet market demand, primarily because we have a parallel pipeline in the same corridor. We have initiated an extensive testing program on the pipeline, including internal inspection and hydrostatic testing. As of the end of the day on May 4, 2004, approximately 85 miles have been hydrotested, representing approximately seventy-seven percent of the testing that is planned to restore portions of the exiting pipeline to temporary service by this summer. In the course of this extensive testing, one leak has been discovered, which will be remediated prior to returning that portion of the line to service. We will be requesting approval from OPS on a segment-by-segment basis upon completion of the testing program. On April 19, 2004, OPS approved returning the first 17-mile segment to service. We have determined that we must restore portions of the existing pipeline to temporary service to ensure our ability to meet customer short-term demands. As currently required by OPS, we plan to then replace the pipeline's entire capacity to meet long-term demands. The total costs are expected to be in the range of approximately $350 million to $410 million over the period 2003 to 2006, including approximately $9 million spent in 2003. The majority of these costs will be spent in 2005 and 2006. We expect to have adequate financial resources to comply with the order and replace the capacity, if required. We anticipate filing a rate case to recover these costs following the in-service date of the replacement facilities.

THREE MONTHS ENDED MARCH 31, 2004 VS. THREE MONTHS ENDED MARCH 31, 2003

	THREE MONTHS ENDED MARCH 31, 2004	THREE MONTHS ENDED MARCH 31, 2003
	(MILLIONS)	
Segment revenues........................	$ 359.0	$ 339.6
Segment profit..........................	$ 147.4	$ 150.3

The $19.4 million, or six percent, increase in Gas Pipeline revenues is due primarily to $18 million of higher transportation revenues associated with expansion projects. The $18 million consists of $10 million at Northwest Pipeline from an expansion project that became operational in October 2003 (Evergreen) and $8 million higher demand revenues on the Transco system resulting from new expansion projects (Trenton-Woodbury, November 2003 and Momentum Phases 1 & 2, May 2003 and February 2004). Revenue also increased due to $10 million higher gas exchange imbalance settlements (substantially offset in costs and operating expenses). Partially offsetting these increases were $3 million lower short term firm revenues and $2 million lower revenues associated with tracked costs, which are passed through to customers (offset in costs and operating expenses).

Costs and operating expenses increased $24 million, or 15 percent, due primarily to $9 million higher fuel expense at Transco reflecting a reduction in pricing differentials on the volumes of gas used in operation as compared to 2003 and $9 million higher gas exchange imbalance settlements (offset in revenues). Costs and operating expenses also increased due to $6 million higher depreciation expense related to additional property, plant and equipment placed into service and $4 million higher expenses associated with non-capitalized maintenance projects. These increases were partially offset by a $5 million reduction of expense in first-quarter 2004 related to an adjustment to depreciation previously recognized and $2 million lower recovery of tracked costs, which are passed through to customers (offset in revenues).

The $2.9 million, or 2 percent, decrease in Gas Pipeline segment profit is due to the $24 million higher costs and operating expenses partially offset by $19.4 million higher revenues and $2.0 million higher equity earnings (included in Investing income (loss)). The increase in equity earnings includes a $2.3 million increase in earnings from our investment in Gulfstream.

EXPLORATION & PRODUCTION

OVERVIEW OF THE THREE MONTHS ENDED MARCH 31, 2004

Production volumes in the first quarter increased, but the benefit of those higher volumes was largely offset by lower contracted hedged prices. In the first quarter of 2004, average daily production was approximately 501 million cubic feet of gas equivalent, up from 491 million cubic feet in the fourth quarter of 2003.

OUTLOOK FOR THE REMAINDER OF 2004

Our expectations for the remainder of the year include:

- A continuing development drilling program in our key basins with an increase in activity in the Piceance basin.

- Increasing our 2003 production level by 10 to 15 percent by the end of 2004. Approximately 80 percent of our forecasted production for the remainder of 2004 is hedged at prices that average $3.66 per mcfe at a basin level.

THREE MONTHS ENDED MARCH 31, 2004 VS. THREE MONTHS ENDED MARCH 31, 2003

The following discussions of the quarter-over-quarter results primarily relate to our continuing operations. However, the results for 2003 include those operations that were sold during 2003 that did not qualify for discontinued operations reporting. The operations classified as discontinued operations are the properties in the Hugoton and Raton basins.

	THREE MONTHS ENDED MARCH 31,	
	2004	2003
	(MILLIONS)	
Segment revenues	$ 165.2	$ 243.9
Segment profit	$ 51.5	$ 113.8

The $78.7 million, or 32 percent decrease in Exploration & Production revenues is due primarily to $47 million lower production revenues reflecting lower net realized average prices and lower production volumes. The remainder of the decrease reflects a reduction in revenues from gas management activities, $10 million lower income from the utilization of excess transportation capacity and $7 million lower income on derivative instruments that did not qualify for hedge accounting.

The decrease in domestic production revenues reflects $33 million associated with a 20 percent decrease in net realized average prices for production and $14 million from an eight percent decrease in net domestic production volumes. Net realized average prices include the effect of hedge positions. The decrease in production volumes primarily relates to the absence of volumes associated with properties sold in the second and third quarter of 2003. Production volumes for our core retained properties were consistent from period to period. We expect volumes to increase towards the end of the year as our drilling program continues.

To minimize the risk and volatility associated with the ownership of producing gas properties, we enter into derivative forward sales contracts, which economically lock in a price for a portion of our future production. Approximately 83 percent of domestic production in the first quarter of 2004 were hedged. These hedging decisions are made considering our overall commodity risk exposure.

Costs and expenses, including selling, general and administrative expenses, decreased $20 million, primarily reflecting the following:

- $13 million lower gas management expenses associated with the lower revenues from gas management activities mentioned above; and

- $4 million lower depreciation, depletion and amortization expense primarily as a result of lower production volumes.

The $62.3 million decrease in segment profit is due primarily to the lower production revenues as discussed above and the lower revenues related to excess transportation capacity and non hedge derivative income.

MIDSTREAM GAS & LIQUIDS

OVERVIEW OF THREE MONTHS ENDED MARCH 31, 2004

Consistent with our strategy to invest in targeted growth areas and divest non-core assets, we placed into service additional infrastructure in the deepwater offshore area of the Gulf of Mexico and expanded the Opal gas processing facility in Wyoming. In the Gulf of Mexico, the Devils Tower platform handling facility and the Gunnison pipeline assets were placed into service in the first quarter of 2004 and are expected to begin contributing to segment profit in the upcoming quarters. The Opal expansion began operating in March of 2004.

OUTLOOK FOR THE REMAINDER OF 2004

The following factors could impact our business in the remaining quarters of 2004 and beyond:

- Continued growth in the deepwater areas of the Gulf of Mexico is expected to contribute to, and become a larger component of, our future segment revenues and segment profit. We expect these additional fee-based revenues to lower our overall exposure to commodity price risks. Incremental revenues related to the Gunnison and Devils Tower deepwater projects are expected to continue growing throughout 2004 and make a significant contribution to total annual segment profit in 2004.

- Our gas processing margins were above the five-year annual average in the first quarter of 2004. However, we do not expect the average annual margin for the remainder of 2004 to exceed this average.

- Beginning in the second quarter of 2003, our Gulf Coast gas processing plants earned additional fee revenues from short-term processing agreements contracted in response to gas merchantability orders from pipeline operators requiring producers' gas to be processed to achieve pipeline quality standards. The termination of these short-term contracts could result in lower Gulf Coast processing revenues. These contracts could be terminated as a result of a shift in regulatory policy or a sustained, long-term period of favorable gas processing margins.

- We continue to evaluate and pursue the sale of various assets. The completion of certain asset sales may have the effect of lowering revenues and/or segment profit in the periods following the sales. We have announced our intent to sell the following assets:

    - Canadian straddle plants (currently reported as discontinued operations),
    - Cameron Meadows/Black Marlin gas gathering and processing assets,
    - Conway NGL fractionator and storage facilities,
    - South Texas gas gathering assets,
    - Ethylene distribution system (Gulf Coast), and
    - Gulf Liquids facility (currently reported as discontinued operations).

Additional fee-based revenues from our new deepwater assets are expected to mitigate segment profit decline resulting from these asset sales. As we continue to evaluate and execute our asset divestiture strategy, certain assets for sale may meet the requirements to be reported as discontinued operations.

THREE MONTHS ENDED MARCH 31, 2004 VS. THREE MONTHS ENDED MARCH 31, 2003

Pursuant to generally accepted accounting principles, we have classified the operations of Gulf Liquids, West Stoddart, Redwater and the Canadian straddle plants as discontinued operations. All prior periods reflect this reclassification.

	THREE MONTHS ENDED MARCH 31,	
	2004	2003
	(MILLIONS)	
Segment revenues	$ 627.3	$ 865.4
Segment profit		
Domestic Gathering & Processing	$ 78.2	$ 100.6
Venezuela	21.5	13.6
Canada	(2.8)	(6.7)
Other	10.7	5.3
Total	$ 107.6	$ 112.8

The $238.1 million decrease in Midstream's revenues is primarily the result of lower trading revenues largely due to the fourth quarter 2003 sale of our wholesale propane business. This decline is partially offset by a $47 million increase as the result of the marketing of natural gas liquids (NGLs) on behalf of our customers. Before 2004, our purchases of customers' NGLs were netted within revenues. In 2004, these purchases of customers' NGLs are reported as a cost of goods sold. In addition, revenues increased $56 million largely due to higher production volumes at our Gulf Coast gas processing plants and olefins facilities as well as higher revenues from our Venezuelan facilities.

Cost and operating expenses declined $222 million as a result of lower trading costs largely due to the sale of our wholesale propane business. This decline is partially offset by the increase in costs related to the increase in NGLs marketed on behalf of customers, as noted above. Also, costs and operating expenses increased as a result of $39 million in higher domestic natural gas purchases used to replace the heating value of NGLs extracted at our gas processing facilities. Also, feedstock purchases at our Gulf Coast olefins facility rose as a result of higher production volumes and market prices.

Total Midstream segment profit for the first quarter of 2004 decreased $5.2 million compared to the first quarter of 2003. Results from our domestic gathering and processing business declined as a result of lower processing margins caused by rising natural gas prices in the West Region. Improved results at our Canadian and Venezuelan facilities as well as the absence of audit adjustments recorded in the first quarter 2003 to our Discovery partnership investment offset lower domestic margins. A more detailed analysis of segment profit of our various operations is presented below.

Domestic Gathering & Processing: The $22.4 million decrease in domestic gathering and processing segment profit includes a $24 million decline in the West Region while the Gulf Coast Region's segment profit increased $2 million.

The $24 million decline in the West Region's segment profit is primarily due to a $21 million decline in gas processing margins highlighting the impact of more favorable margins realized during the first quarter of 2003. Both quarters experienced strong NGL prices supported by high crude prices. In the first quarter of 2003, our West Region plants yielded very favorable gas processing margins as transportation constraints created downward price pressure on Wyoming natural gas prices. During that period, gas prices were 64 percent of those in the Gulf Coast area. However, with the additional pipeline capacity provided by the completion of the Kern River Pipeline system, Wyoming's gas prices rebounded in the first quarter of 2004 to 89 percent of Gulf Coast area prices.

Segment profit for our Gulf Coast Region increased slightly compared to the first quarter of 2003. Gas processing margins improved $2 million due to significantly higher production volumes stemming from new processing agreements created to allow producers' gas to be processed to achieve pipeline quality standards. In addition, we resolved a 1999 gas measurement contingent liability resulting in a $3 million favorable impact to segment profit. Offsetting these increases is $3 million in depreciation expense relating to the Devils Tower and Gunnison projects. These projects will not begin to contribute material revenues until the second quarter of 2004.

Venezuela: Segment profit for our Venezuelan assets increased $7.9 million as a result of a fire at the El Furrial facility that reduced revenues by $10 million in the first quarter of 2003. Partially offsetting this increase was lower equity earnings from our investment in the Accroven partnership and higher currency revaluation expenses. Our Venezuelan assets are currently operated for

the exclusive benefit of Petroleos de Venezuela S.A. (PDVSA), the state owned Petroleum Corporation of Venezuela. The Venezuelan economic and political environment can be volatile, but has not significantly impacted the operations and cash flows of our facilities.

Effective February 7, 2004, the Venezuelan government revalued the fixed exchange rate for their local currency from 1,600 Bolivars to the dollar to 1,920 Bolivars to the dollar. This effect of this Bolivar devaluation was recorded in the first quarter of 2004 as a $1.3 million charge to earnings.

Canada: Segment profit for our Canadian operations improved $3.9 million as a result of lower operating expenses and currency translation adjustments. General and administrative expenses were $2 million less due to the effect of the 2003 asset sales. In addition, currency translation adjustments were also favorable by $2 million as a result of a strengthening Canadian dollar. These favorable variances are partially offset by $1 million lower olefins production margins at our Redwater/Fort McMurray facility.

Other: The $5.4 million increase in segment profit for our other operations is primarily due to higher domestic olefins margins and favorable partnership earnings, as follows:

- Segment profit for our Domestic Olefins operations increased $4 million primarily as a result of improved olefins fractionation prices attributed to lower ethylene supplies and higher demand for olefins products. Ethylene production volumes increased 40 percent compared to the first quarter of 2003 primarily due to a new contract with a major customer.

- Earnings from partially owned domestic assets accounted for using the equity method are $8 million higher due primarily to prior period accounting adjustments on the Discovery partnership recorded during the first quarter of 2003.

- Segment profit for our Trading, Fractionation, and Storage group declined $6 million primarily due to $10 million lower net trading revenues caused by the sale of our wholesale propane business in the fourth quarter of 2003 and the quarterly lower of cost or market valuation of NGL line fill inventories. Lower selling, general and administrative expenses and other charges comprise the remaining offsetting variance.

OTHER

	THREE MONTHS ENDED MARCH 31,	
	2004	2003
	(MILLIONS)	
Segment revenues	$ 12.6	$ 28.0
Segment profit (loss)	$ (8.7)	$ 4.8

Other segment revenues for first-quarter 2003 include approximately $14 million of revenues related to certain butane blending assets, which were sold during third-quarter 2003.

Other segment loss for 2004 includes $6.5 million net unreimbursed advisory fees related to the recapitalization of Longhorn Partners Pipeline, L.P. (Longhorn) in February 2004. If the project achieves certain future performance measures, the unreimbursed fees may be recovered. As a result of this recapitalization, we sold a portion of our equity investment in Longhorn for $11.4 million, received $58 million in repayment of a portion of our advances to Longhorn and converted the remaining advances, including accrued interest, into preferred equity interests in Longhorn. These preferred equity interests are subordinate to the preferred interests held by the new investors. Other than the unreimbursed fees, no gain or loss was recognized on this transaction.

FAIR VALUE OF TRADING DERIVATIVES

The chart below reflects the fair value of derivatives held for trading purposes as of March 31, 2004. We have presented the fair value of assets and liabilities by the period in which we expect them to be realized.

TO BE REALIZED IN 1-12 MONTHS (YEAR 1)	TO BE REALIZED IN 13-36 MONTHS (YEARS 2-3)	TO BE REALIZED IN 36-60 MONTHS (YEARS 4-5)	TO BE REALIZED IN 61-120 MONTHS (YEARS 6-10)	TOTAL FAIR VALUE
		(MILLIONS)		
$ (63)	$ 8	$ (14)	$ (2)	$ (71)

As the table above illustrates, we are not materially engaged in trading activities. However, we hold a substantial portfolio of non-trading derivative contracts. Non-trading derivative contracts are those that hedge or could possibly hedge Power's long-term structured contract position and the activities of our other segments on an economic basis. Certain of these economic hedges have not been designated as or do not qualify as SFAS No. 133 hedges. As such, changes in the fair value of these derivative contracts are reflected in earnings. We also hold certain derivative contracts, which do qualify as SFAS No. 133 cash flow hedges, which primarily hedge Exploration & Production's forecasted natural gas sales. As of March 31, 2004, the fair value of these non-trading derivative contracts was a net asset of $281 million.

COUNTERPARTY CREDIT CONSIDERATIONS

We include an assessment of the risk of counterparty non-performance 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, 2004, we held collateral support of $426 million.

We also enter into netting agreements to mitigate counterparty performance and credit risk. During first-quarter 2004, we did not incur any significant losses due to recent counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts as of March 31, 2004 is summarized below.

COUNTERPARTY TYPE	INVESTMENT GRADE(a)	TOTAL
	(MILLIONS)	
Gas and electric utilities	$ 1,219.4	$ 1,361.9
Energy marketers and traders	2,559.6	4,989.1
Financial institutions	1,117.2	1,117.2
Other	3.7	8.6
	$ 4,899.9	7,476.8
Credit reserves		(52.9)
Gross credit exposure from derivatives(b)		$ 7,423.9

We assess our credit exposure on a net basis. The net credit exposure from our derivatives as of March 31, 2004 is summarized below.

COUNTERPARTY TYPE	INVESTMENT GRADE(a)	TOTAL
	(MILLIONS)	
Gas and electric utilities	$ 593.5	$ 604.6
Energy marketers and traders	60.6	434.1
Financial institutions	175.0	175.0
Other	2.4	2.7
	$ 831.5	1,216.4
Credit reserves		(52.9)
Net credit exposure from derivatives(b)		$ 1,163.5

(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.

(b) One counterparty within the California power market represents more than ten percent of the derivative assets and is included in investment grade. Standard & Poor's and Moody's Investors Service do not currently rate this counterparty. We included this counterparty in the investment grade column based upon contractual credit requirements in the event of assignment or substitution of a new obligation for the existing one.

FINANCIAL CONDITION AND LIQUIDITY

LIQUIDITY

Overview

Entering 2003, we faced significant liquidity challenges with sizeable maturing debt obligations and limited financial flexibility. In February 2003, we outlined our planned business strategy to address these challenges, which included reducing debt and increasing our liquidity through asset sales, strategic levels of financing and reductions of operating costs.

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, we successfully executed certain critical components of our plan during 2003. Key execution steps for 2004 and beyond include the following:

- completion of planned asset sales, which are estimated to generate proceeds of approximately $800 million in 2004;
- additional reductions of our SG&A costs;
- the replacement of our cash-collateralized letter of credit and revolver facility with facilities that do not encumber cash; and
- continuation of our efforts to exit from the Power business.

Sources of liquidity

Our liquidity is derived from both internal and external sources. Certain of those sources are available to us (at the parent level) and others are available to certain of our subsidiaries.

At March 31, 2004, we have the following sources of liquidity:

- Cash-equivalent investments at the corporate level of $1.7 billion as compared to $2.2 billion at December 31, 2003.
- Cash and cash-equivalent investments of various international and domestic entities of $259 million, as compared to $91 million at December 31, 2003.

At March 31, 2004, we have capacity of $532 million available under our $800 million revolving and letter of credit facility compared to $447 million at December 31, 2003. In June 2003, we entered into this revolving and letter of credit facility, which is used primarily for issuing letters of credit and must be collateralized at 105 percent of the level utilized (see Note 10 of Notes to Consolidated Financial Statements).

We have an effective shelf registration statement with the Securities and Exchange Commission that authorizes us to issue an additional $2.2 billion of a variety of debt and equity securities. However, the ability to utilize this shelf registration for debt securities is restricted by certain covenants associated with our $800 million 8.625 percent senior unsecured notes.

In addition, our wholly owned subsidiaries Northwest Pipeline and Transco have outstanding registration statements filed with the Securities and Exchange Commission. As of March 31, 2004, approximately $350 million of shelf availability remains under these registration statements. However, the ability to utilize these registration statements is restricted by certain covenants associated with our $800 million 8.625 percent senior unsecured notes. Interest rates, market conditions, and industry conditions will affect amounts raised, if any, in the capital markets.

During the first three months of 2004, we satisfied liquidity needs with:

- $279 million in cash generated from the sale of the Alaska refinery and related assets, and

- $149.9 million in cash generated from cash flows of continuing operations.

Outlook for the remainder of 2004

We estimate capital and investment expenditures will be approximately $725 million to $825 million for 2004. During the remainder of 2004, we expect to fund capital and investment expenditures, debt payments and working-capital requirements through (1) cash and cash equivalent investments on hand, (2) cash generated from operations, and (3) cash generated from the sale of assets. We expect to realize approximately $800 million from asset sales in 2004 (including the $279 million of cash received from the March 31, 2004 sale of the Alaska refinery) and expect to generate $1.0 to $1.3 billion in cash flow from continuing operations.

In April 2004, we entered into two unsecured bank revolving credit facilities totaling $500 million. These facilities provide for borrowings and letters of credit, but will be used primarily for issuing letters of credit. During April 2004, use of these new facilities released approximately $500 million of restricted cash, restricted investments and margin deposits. Also, on May 3, 2004 we entered into a new three-year, $1 billion secured revolving credit facility which is available for borrowings and letters of credit. Northwest Pipeline and Transco have access to $400 million each under the facility. The new facility is secured by certain Midstream assets and a guarantee from WGP (see Note 10 of Notes to the Consolidated Financial Statements).

In the remainder of 2004, we expect to make significant additional progress towards debt reduction while maintaining management's estimate of appropriate levels of cash and other forms of liquidity. To manage our operations and meet unforeseen or extraordinary calls on cash, we expect to maintain cash and/or liquidity levels of at least $1 billion. While our access to the capital markets continues to improve, one of our indentures, as well as the two unsecured facilities closed in April, have covenants that restrict our ability to issue new debt, with minimal exceptions, until a certain fixed charge coverage ratio is achieved. We expect to satisfy this requirement by the end of 2005.

Credit ratings

As part of executing the business plan announced in February of 2003, we established a goal of returning to investment grade status. While reduction of debt is viewed as a key contributor towards this goal, certain of the key credit rating agencies have imputed the financial commitments associated with our long-term tolling agreements within the Power business as debt. If we are unable to achieve our goal of exiting the Power business and/or the elimination of these commitments, receiving an investment grade rating may be further delayed. See Note 1 of Notes to Consolidated Financial Statements for a further discussion on the Power business status.

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

As discussed previously, in April 2004, we entered into two unsecured bank revolving credit facilities totaling $500 million. We were able to obtain the unsecured credit facilities because the bank syndicated its associated credit risk into the institutional investor market via a 144A offering. Upon the occurrence of certain credit events, outstanding letters of credit become cash collateralized creating a borrowing under the facilities, and concurrently the bank can deliver the facilities to the institutional investors, whereby the investors replace the bank as lender under the facilities.

The bank established trusts funded by the institutional investors, whereby the assets of the trusts serve as collateral to reimburse the bank for our borrowings in the event the facilities are delivered to the investors. We have no asset securitization or collateral requirements under the new facilities. During April 2004, use of these new facilities released approximately $500 million of restricted cash, restricted investments and margin deposits (see Note 10 of Notes to the Consolidated Financial Statements).

OPERATING ACTIVITIES

In the first quarter of 2003, we recorded an accrual for fixed rate interest included in the RMT Note on the Consolidated Statement of Cash Flows representing the quarterly non-cash reclassification of the deferred fixed rate interest from an accrued liability to the RMT Note. The amortization of deferred set-up fee and fixed rate interest on the RMT Note relates to amounts recognized in the income statement as interest expense, which were not payable until maturity. The RMT Note was repaid in May 2003.

Items reflected as discontinued operations within operating activities in the Consolidated Statement of Cash Flows include approximately $70 million in use of funds related to the timing of settling working capital issues of the Alaska refinery and related assets. We expect to receive the proceeds from the collection of approximately $58 million in trade receivables related to the Alaska refinery and related assets in the second quarter.

FINANCING ACTIVITIES

On March 15, 2004, we retired the remaining $679 million obligation pertaining to the outstanding balance of the 9.25 percent senior unsecured Notes due March 15, 2004. The $679 million represented the remaining amount of the Notes subsequent to the fourth-quarter 2003 tender which retired $721 million of the original $1.4 billion balance.

For a discussion of other borrowings and repayments in 2004, see Note 10 of Notes to Consolidated Financial Statements.

Dividends paid on common stock are currently $.01 per common share on a quarterly basis and totaled $5.2 million for the three months ended March 31, 2004. One of the covenants under the indenture for the $800 million senior unsecured notes due 2010 currently limits our quarterly common stock dividends to not more than $.02 per common share. This restriction will be removed in the future if certain requirements in the covenants are met.

INVESTING ACTIVITIES

During the first quarter of 2004, we purchased $235.9 million of restricted investments comprised of U.S. Treasury notes and retired $331.2 million on their scheduled maturity date. We made these purchases to satisfy the 105 percent cash collateralization covenant in the $800 million revolving credit facility (see Note 10 of Notes to Consolidated Financial Statements).

During February 2004, we were a party to a recapitalization plan completed by Longhorn Partners Pipeline, L.P. (Longhorn). As a result of this plan, we received $58 million in repayment of a portion of our advances to Longhorn and converted the remaining advances, including accrued interest, into preferred equity interests in Longhorn. The $58 million received is included in Proceeds from dispositions of investments and other assets.

The following first-quarter sales provided significant proceeds from sales and may include various adjustments subsequent to the actual date of sale.

In 2004:

- $279 million of cash proceeds related to the sale of Alaska refinery, retail and pipeline and related assets.

In 2003:

- $453 million related to the sale of the Midsouth refinery;
- $188 million related to the sale of the Williams travel centers; and
- $40 million related to the sale of the Worthington facility.

CONTRACTUAL OBLIGATIONS

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, we had certain contractual obligations at December 31, 2003, with various maturity dates, related to the following:

- notes payable;
- long-term debt;
- capital and operating leases;
- purchase obligations; and
- other long-term liabilities, including physical and financial derivatives.

During the first-quarter 2004, the amount of our contractual obligations changed significantly due to the following:

- On March 15, 2004, we retired the remaining $679 million obligation pertaining to the outstanding balance of the 9.25 percent senior unsecured Notes due March 15, 2004.
- Power's physical and financial derivative obligations decreased by approximately $483 million. The decrease is due to normal trading and market activity and the expiration of obligations related to the first three months of 2004.
- As part of the sale of the Alaska refinery, we terminated a $385 million crude purchase contract with the state of Alaska.

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EXHIBIT 99.5

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

(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS)	THREE MONTHS ENDED JUNE 30, 2004	THREE MONTHS ENDED JUNE 30, 2003*	SIX MONTHS ENDED JUNE 30, 2004	SIX MONTHS ENDED JUNE 30, 2003*
Revenues:				
Power	$ 2,333.2	$ 2,940.2	$ 4,629.6	$ 6,721.7
Gas Pipeline	331.0	330.7	690.0	670.3
Exploration & Production	189.0	200.2	354.2	444.1
Midstream Gas & Liquids	630.5	502.2	1,257.8	1,367.6
Other	7.0	20.1	19.6	48.1
Intercompany eliminations	(442.0)	(381.1)	(837.0)	(863.4)
Total revenues	3,048.7	3,612.3	6,114.2	8,388.4
Segment costs and expenses:				
Costs and operating expenses	2,658.3	3,024.8	5,348.2	7,448.4
Selling, general and administrative expenses	81.9	115.4	166.3	221.0
Other (income) expense - net	23.0	(225.3)	31.4	(224.6)
Total segment costs and expenses	2,763.2	2,914.9	5,545.9	7,444.8
General corporate expenses	28.3	21.8	60.3	44.7
Operating income (loss):				
Power	24.2	364.7	13.1	234.2
Gas Pipeline	128.3	113.4	272.2	261.9
Exploration & Production	40.1	176.2	88.7	287.9
Midstream Gas & Liquids	96.1	51.6	199.7	167.0
Other	(3.2)	(8.5)	(5.4)	(7.4)
General corporate expenses	(28.3)	(21.8)	(60.3)	(44.7)
Total operating income	257.2	675.6	508.0	898.9
Interest accrued	(222.3)	(405.9)	(465.6)	(758.7)
Interest capitalized	.7	11.3	4.7	23.2
Interest rate swap income (loss)	6.8	(6.1)	(1.3)	(8.9)
Investing income (loss)	11.7	(43.2)	22.0	3.1
Early debt retirement costs	(96.8)	--	(97.3)	--
Minority interest in income of consolidated subsidiaries	(6.0)	(6.0)	(10.8)	(9.5)
Other income (expense) - net	13.4	13.9	14.8	36.0
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	(35.3)	239.6	(25.5)	184.1
Provision (benefit) for income taxes	(17.3)	125.9	(6.0)	113.5
Income (loss) from continuing operations	(18.0)	113.7	(19.5)	70.6
Income (loss) from discontinued operations	(.2)	156.0	11.2	145.9
Income (loss) before cumulative effect of change in accounting principles	(18.2)	269.7	(8.3)	216.5
Cumulative effect of change in accounting principles	--	--	--	(761.3)
Net income (loss)	(18.2)	269.7	(8.3)	(544.8)
Preferred stock dividends	--	22.7	--	29.5
Income (loss) applicable to common stock	$ (18.2)	$ 247.0	$ (8.3)	$ (574.3)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ (.03)	$ .18	$ (.04)	$ .08
Income (loss) from discontinued operations	--	.30	.02	.28
Income (loss) before cumulative effect of change in accounting principles	(.03)	.48	(.02)	.36
Cumulative effect of change in accounting principles	--	--	--	(1.47)
Net income (loss)	$ (.03)	$ .48	$ (.02)	$ (1.11)
Weighted-average shares (thousands)	521,698	518,090	520,592	517,872
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ (.03)	$ .17	$ (.04)	$ .07
Income (loss) from discontinued operations	--	.29	.02	.28
Income (loss) before cumulative effect of change in accounting principles	(.03)	.46	(.02)	.35
Cumulative effect of change in accounting principles	--	--	--	(1.45)
Net income (loss)	$ (.03)	$ .46	$ (.02)	$ (1.10)
Weighted-average shares (thousands)	521,698	534,839	520,592	523,553

Cash dividends per common share	$ .01	$ .01	$ .02	$ .02

* Certain amounts have been reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

See accompanying notes.

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

(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS)	JUNE 30, 2004	DECEMBER 31, 2003*
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,030.3	$ 2,315.7
Restricted cash	45.2	47.1
Restricted investments	--	93.2
Accounts and notes receivable less allowance of $102.8 ($112.2 in 2003)	1,461.0	1,613.2
Inventories	255.3	242.9
Derivative assets	3,936.1	3,166.8
Margin deposits	423.7	553.9
Assets of discontinued operations	434.8	441.3
Deferred income taxes	68.2	106.6
Other current assets and deferred charges	107.4	214.3
Total current assets	7,762.0	8,795.0
Restricted cash	131.0	159.8
Restricted investments	--	288.1
Investments	1,363.0	1,463.6
Property, plant and equipment, at cost	16,043.4	15,752.3
Less accumulated depreciation and depletion	(4,273.3)	(4,018.3)
	11,770.1	11,734.0
Derivative assets	3,435.8	2,495.6
Goodwill	1,014.5	1,014.5
Assets of discontinued operations	--	345.1
Other assets and deferred charges	692.0	726.1
Total assets	$ 26,168.4	$ 27,021.8
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Notes payable	$ --	$ 3.3
Accounts payable	1,044.8	1,228.0
Accrued liabilities	859.9	944.4
Liabilities of discontinued operations	24.3	95.7
Derivative liabilities	3,979.2	3,064.2
Long-term debt due within one year	276.6	935.2
Total current liabilities	6,184.8	6,270.8
Long-term debt	9,483.0	11,039.8
Deferred income taxes	2,326.3	2,453.4
Derivative liabilities	3,179.4	2,124.1
Other liabilities and deferred income	906.3	947.5
Contingent liabilities and commitments (Note 13)		
Minority interests in consolidated subsidiaries	89.7	84.1
Stockholders' equity:		
Common stock, $1 per share par value, 960 million shares authorized, 525.6 million issued in 2004, 521.4 million issued in 2003	525.6	521.4
Capital in excess of par value	5,217.0	5,195.1
Accumulated deficit	(1,445.5)	(1,426.8)
Accumulated other comprehensive loss	(235.5)	(121.0)
Other	(24.1)	(28.0)
	4,037.5	4,140.7
Less treasury stock (at cost), 3.2 million shares of common stock in 2004 and 2003	(38.6)	(38.6)
Total stockholders' equity	3,998.9	4,102.1
Total liabilities and stockholders' equity	$ 26,168.4	$ 27,021.8

* Certain amounts have been reclassified as described in Note 2 to Consolidated Financial Statements.

See accompanying notes.

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

	SIX MONTHS ENDED JUNE 30, 2004	2003*
	(MILLIONS)	
OPERATING ACTIVITIES:		
Income (loss) from continuing operations	$ (19.5)	$ 70.6
Adjustments to reconcile to cash provided (used) by operations:		
Depreciation, depletion and amortization	328.5	329.8
Provision (benefit) for deferred income taxes	(19.5)	79.6
Provision for loss on investments, property and other assets	30.0	120.8
Net gain on disposition of assets	(2.0)	(100.6)
Provision for uncollectible accounts	(4.8)	6.0
Minority interest in income of consolidated subsidiaries	10.8	9.5
Amortization of stock-based awards	7.5	21.4
Payment of deferred set-up fee and fixed rate interest on RMT note payable	--	(265.0)
Accrual for fixed rate interest included in the RMT note payable	--	99.3
Amortization of deferred set-up fee and fixed rate interest on RMT note payable	--	154.5
Cash provided (used) by changes in current assets and liabilities:		
Restricted cash	2.8	(.5)
Accounts and notes receivable	150.0	682.3
Inventories	(12.5)	42.0
Margin deposits	130.2	195.2
Other current assets and deferred charges	105.0	(61.0)
Accounts payable	(144.8)	(462.8)
Accrued liabilities	(142.7)	(205.7)
Changes in current and noncurrent derivative assets and liabilities	77.7	(356.8)
Changes in noncurrent restricted cash	11.0	(2.4)
Other, including changes in noncurrent assets and liabilities	95.9	47.9
Net cash provided by operating activities of continuing operations	603.6	404.1
Net cash provided by operating activities of discontinued operations	11.5	64.8
Net cash provided by operating activities	615.1	468.9
FINANCING ACTIVITIES:		
Payments of notes payable	(3.3)	(892.8)
Proceeds from long-term debt	--	1,776.5
Payments of long-term debt	(2,217.0)	(919.3)
Proceeds from issuance of common stock	11.9	.1
Dividends paid	(10.4)	(42.9)
Repurchase of preferred stock	--	(275.0)
Payments of debt issuance costs	(20.4)	(54.9)
Premiums paid on tender offer and early debt retirement	(79.5)	--
Payments/dividends to minority interests	(5.2)	(.7)
Changes in restricted cash	16.9	62.2
Changes in cash overdrafts	(27.4)	(25.9)
Other - net	(3.1)	(.1)
Net cash used by financing activities of continuing operations	(2,337.5)	(372.8)
Net cash used by financing activities of discontinued operations	(1.2)	(93.1)
Net cash used by financing activities	(2,338.7)	(465.9)
INVESTING ACTIVITIES:		
Property, plant and equipment:		
Capital expenditures	(329.0)	(449.8)
Proceeds from dispositions	3.0	467.9
Purchases of investments/advances to affiliates	(1.6)	(13.3)
Purchases of restricted investments	(471.8)	(463.3)
Proceeds from sales of businesses	306.0	1,943.6
Proceeds from sale of restricted investments	851.4	--
Proceeds from dispositions of investments and other assets	85.2	33.3
Other - net	(6.7)	(3.5)
Net cash provided by investing activities of continuing operations	436.5	1,514.9
Net cash used by investing activities of discontinued operations	(.8)	(24.2)
Net cash provided by investing activities	435.7	1,490.7
Increase (decrease) in cash and cash equivalents	(1,287.9)	1,493.7
Cash and cash equivalents at beginning of period**	2,318.2	1,736.0
Cash and cash equivalents at end of period**	$ 1,030.3	$ 3,229.7

* Certain amounts have been reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

** Includes cash and cash equivalents of discontinued operations of $2.5 million, $2.6 million and $85.6 million at December 31, 2003, June 30, 2003 and December 31, 2002, respectively.

See accompanying notes.

1. GENERAL

Company overview and outlook

In February 2003, we outlined our planned business strategy in response to the events that significantly impacted the energy sector and our company during late 2001 and much of 2002, including the collapse of Enron and the severe decline of the telecommunications industry. The plan focused on migrating to an integrated natural gas business comprised of a strong, but smaller, portfolio of natural gas businesses; reducing debt; and increasing our liquidity through asset sales, strategic levels of financing and reductions in operating costs. The plan was designed to address near-term and medium-term debt and liquidity issues, to de-leverage the company with the objective of returning to investment grade status and to develop a balance sheet and cash flows capable of supporting and ultimately growing our remaining businesses.

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, we successfully executed certain critical components of our plan during 2003. Key execution steps for 2004 and beyond included the completion of planned asset sales; additional reductions of our selling, general and administrative (SG&A) costs; the replacement of our cash-collateralized letter of credit and revolver facility with facilities that do not encumber cash; and continuation of efforts to exit from the Power business (see below).

Asset sales during 2004 were initially expected to generate proceeds of approximately $800 million. In first-quarter 2004, we completed the sale of our Alaska refinery and related assets for approximately $304 million. On July 28, 2004, we completed the sale of three straddle plants in western Canada for approximately $536 million (see Note 6). In addition to these transactions, we currently expect to generate additional proceeds from the sale of assets of approximately $50 to $100 million.

In April 2004, we entered into two new unsecured credit facilities totaling $500 million, which will be used primarily for issuing letters of credit. During April 2004, use of these new facilities released approximately $500 million of restricted cash, restricted investments and margin deposits (see Note 12). Also, on May 3, 2004, we entered into a new three-year $1 billion secured revolving credit facility. The revolving credit facility is secured by certain Midstream assets and a guarantee from Williams Gas Pipeline Company, LLC. (WGP) (see Note 12).

In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of a specified series of our outstanding notes and debentures. As of the June 8, 2004, tender offer expiration date, we had accepted for purchase $1.17 billion of the notes for purchase (see Note 12). In May 2004, we also repurchased debt of approximately $255 million of various maturities on the open market. Our repurchase of these notes served to decrease debt and will result in reduced annual interest expense.

Power Business Status

Since mid-2002, we have been pursuing a strategy of exiting the Power business and have worked with financial advisors to assist with this effort. To date, several factors have contributed to the difficulty of achieving a complete exit from this business, including the following with respect to the wholesale power industry:

- oversupply position in most markets expected through the balance of the decade;
- slow North American gas supply response to high gas prices; and
- expectations of hybrid regulated/deregulated market structure for several years.

As a result of these factors and the size of our Power business, the number of financially viable parties expressing an interest in purchasing the entire business has been limited. Additionally, the current and near term view of the wholesale power market, which we interpret as depressed, has strongly influenced these parties' view of value and related risk associated with this business.

Notes (Continued)

Because market conditions may change, and we cannot determine the impact of this on a buyer's point of view, amounts ultimately received in any portfolio sale, contract liquidation or realization may be significantly different from the estimated economic value or carrying values reflected in the Consolidated Balance Sheet. In addition, our tolling agreements are not derivatives and thus have no carrying value in the Consolidated Balance Sheet pursuant to the application of Emerging Issues Task Force (EITF) Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3). Based on current market conditions, certain of these agreements are forecasted to realize significant future losses. It is possible that we may sell contracts for less than their carrying value or enter into agreements to terminate certain obligations, either of which could result in significant future loss recognition or reductions of future cash flows.

We continue to evaluate alternatives and discuss our plans and operating strategy for the Power business with our Board of Directors. As an alternative to continuing a plan of pursuing a complete exit from the Power business, we are evaluating whether the benefits of realizing the positive cash flows expected to be generated by this business through continued ownership exceed the benefits of a sale at a depressed price. If we pursue this alternative, we expect to continue our current program of managing this business to minimize financial risk, generate cash and manage existing contractual commitments.

Other

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, as restated and amended. The accompanying unaudited financial statements include all normal recurring adjustments and others, including asset impairments, loss accruals, and the change in accounting principles which, in the opinion of our management, are necessary to present fairly our financial position at June 30, 2004, and results of operations for the three and six months ended June 30, 2004 and 2003 and cash flows for the six months ended June 30, 2004 and 2003.

During the second quarter of 2003, we corrected the accounting treatment previously applied to certain third-party derivative contracts during 2002 and 2001. We previously disclosed this in our Form 10-Q for the second quarter of 2003 and in our Form 10-K for the year ended December 31, 2003. Results through June 30, 2003, include $106.8 million of revenue attributable to prior periods. Our management, after consultation with our independent auditor, concluded that the effect of the previous accounting treatment was not material to 2003 and earlier periods and the trend of earnings.

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.

2. BASIS OF PRESENTATION

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, financial position and cash flows of certain components as discontinued operations (see Note 6).

During second-quarter 2004, our Board of Directors approved a plan authorizing management to negotiate and facilitate a sale of our straddle plants in western Canada, which were part of the Midstream segment. As a result, these assets and their related income and cash flows are now reported as discontinued operations. In addition, the following components are included as discontinued operations:

- retail travel centers concentrated in the Midsouth, part of the previously reported Petroleum Services segment;

- refining and marketing operations in the Midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;

- Texas Gas Transmission Corporation, previously one of Gas Pipeline's segments;

- natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment;

- o bio-energy operations, part of the previously reported Petroleum Services segment;

- o our general partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;

- o the Colorado soda ash mining operations, part of the previously reported International segment;

- o certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream segment;

- o refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment; and

- o Gulf Liquids New River Project LLC, previously part of the Midstream segment.

Unless indicated otherwise, the information in the Notes to the Consolidated Financial Statements relates to our continuing operations. Other components of our business may be classified as discontinued operations in the future as those operations are sold or classified as held-for-sale.

We have restated all segment information in the Notes to Consolidated Financial Statements for the prior periods presented to reflect the discontinued operations noted above. Certain other statement of operations, balance sheet and cash flow amounts have been reclassified to conform to the current classifications.

3. CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLES

Energy commodity risk management and trading activities and revenues

Effective January 1, 2003, we adopted EITF 02-3. As a result of initial application of this Issue, we reduced net income by $762.5 million (net of a $471.4 million benefit for income taxes) in first-quarter 2003. Approximately $755 million of the reduction in net income relates to Power, with the remainder relating to Midstream. The reduction of net income is reported as a cumulative effect of a change in accounting principle. The change resulted primarily from power tolling, load serving, transportation and storage contracts not meeting the definition of a derivative and no longer being reported at fair value.

Asset retirement obligations

Effective January 1, 2003, we also adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." As required by the new standard, we recorded liabilities equal to the present value of expected future asset retirement obligations at January 1, 2003. As a result of the adoption of SFAS No. 143, we recorded a credit to earnings of $1.2 million (net of a $.1 million provision for income taxes) reflected as a cumulative effect of a change in accounting principle. In connection with adoption of SFAS No. 143, we changed our method of accounting to include salvage value of equipment related to producing wells in the calculation of depreciation. The impact of this change is included in the effect of adoption.

Notes (Continued)

4. ASSET SALES, IMPAIRMENTS AND OTHER ACCRUALS

Significant gains or losses from asset sales, impairments and other accruals included in other (income) expense - net within segment costs and expenses and investing income (loss) are included in the following tables.

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
OTHER (INCOME) EXPENSE-NET:				
POWER				
Gain on sale of Jackson power contract	$ --	$ (175.0)	$ --	$ (175.0)
Commodity Futures Trading Commission settlement (see Note 13)	--	20.0	--	20.0
GAS PIPELINE				
Write-off of software development costs due to cancelled implementation	--	25.5	--	25.5
Write-off of previously-capitalized costs	9.0	--	9.0	--
EXPLORATION & PRODUCTION				
Net gain on sale of natural gas properties	--	(91.5)	--	(91.5)
Loss provision related to an ownership dispute	11.3	--	11.3	--

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
INVESTING INCOME (LOSS):				
POWER				
Impairment of Aux Sable investment	$ --	$ (8.5)	$ --	$ (8.5)
OTHER				
Impairment of cost-based investment	--	(13.5)	--	(13.5)
Longhorn Partners Pipeline, L.P.				
Impairment of investment	(10.8)	(42.4)	(10.8)	(42.4)
Net unreimbursed Longhorn recapitalization advisory fees	--	--	(6.5)	--
Impairment of Algar Telecom S.A. investment	(1.1)	--	(1.1)	(12.0)

5. PROVISION (BENEFIT) FOR INCOME TAXES

The provision (benefit) for income taxes from continuing operations includes:

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
Current:				
Federal	$ .1	$ 6.2	$ 3.3	$ 12.5
State	2.6	8.5	4.4	13.2
Foreign	3.3	8.2	5.8	8.2
	6.0	22.9	13.5	33.9
Deferred:				
Federal	(13.0)	103.2	(13.6)	86.6
State	(12.6)	(2.1)	(10.5)	(5.1)
Foreign	2.3	1.9	4.6	(1.9)
	(23.3)	103.0	(19.5)	79.6
Total provision (benefit)	$ (17.3)	$ 125.9	$ (6.0)	$ 113.5

Notes (Continued)

The effective income tax rate benefit for the three months ended June 30, 2004, is greater than the federal statutory rate due primarily to the effect of state income taxes partially offset by net foreign operations and an accrual for income tax contingencies.

The effective income tax rate benefit for the six months ended June 30, 2004, is less than the federal statutory rate due primarily to net foreign operations and an accrual for income tax contingencies partially offset by the effect of state income taxes.

The effective income tax rate for the three and six months ended June 30, 2003, is greater than the federal statutory rate due primarily to the financial impairment of certain investments, capital losses generated for which valuation allowances were established, nondeductible expenses and an accrual for income tax contingencies.

6. DISCONTINUED OPERATIONS

During 2002, we began the process of selling assets and/or businesses to address liquidity issues. The businesses discussed below represent components that have been sold or approved for sale by our Board of Directors as of June 30, 2004; therefore, their results of operations (including any impairments, gains or losses), financial position and cash flows have been reflected in the consolidated financial statements and notes as discontinued operations.

SUMMARIZED RESULTS OF DISCONTINUED OPERATIONS

The following table presents the summarized results of discontinued operations for the three and six months ended June 30, 2004 and June 30, 2003. Income from discontinued operations before income taxes for the six months ended June 30, 2004 includes a first-quarter charge of $17.4 million to increase our accrued liability associated with certain Quality Bank litigation matters (see Note 13).

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
Revenues	$ 45.3	$ 628.4	$ 339.6	$ 1,846.3
Income (loss) from discontinued operations before income taxes	(2.9)	22.6	8.2	119.4
(Impairments) and gain (loss) on sales - net	.1	232.9	7.0	115.6
Benefit (provision) for income taxes	2.6	(99.5)	(4.0)	(89.1)
Income (loss) from discontinued operations	$ (.2)	$ 156.0	$ 11.2	$ 145.9

SUMMARIZED ASSETS AND LIABILITIES OF DISCONTINUED OPERATIONS

The following table presents the summarized assets and liabilities of discontinued operations as of June 30, 2004 and December 31, 2003. The December 31, 2003 balances include the assets and liabilities of the Canadian straddle plants, the Gulf Liquids New River Project LLC (Gulf Liquids) and the Alaska refining, retail and pipeline operations. The June 30, 2004 balances include the Canadian straddle plants, Gulf Liquids and certain remaining working capital amounts of the Alaska refining, retail and pipeline operations. The assets and liabilities from discontinued operations are reflected on the Consolidated Balance Sheet as current beginning in the period they are both approved for sale and expected to be sold within twelve months.

	JUNE 30, 2004	DECEMBER 31, 2003
	(MILLIONS)	
Total current assets	$ 46.6	$ 175.4
Property, plant and equipment - net	386.6	609.0
Other non-current assets	1.6	2.0
Total non-current assets	388.2	611.0
Total assets	$ 434.8	$ 786.4
Long-term debt due within one year	--	1.2
Other current liabilities	23.4	81.5
Total current liabilities	$ 23.4	$ 82.7
Long-term debt	--	.3
Other non-current liabilities	.9	12.7
Total non-current liabilities	.9	13.0
Total liabilities	$ 24.3	$ 95.7

HELD FOR SALE AT JUNE 30, 2004

Canadian straddle plants

During second-quarter 2004, our Board of Directors approved a plan to negotiate and facilitate the sale of our three natural gas liquid extraction plants (straddle plants) in western Canada. On July 28, 2004, we closed the sale of these facilities for approximately $536 million in U.S. funds. We expect to recognize a pre-tax gain of approximately $190 million on the sale in third-quarter 2004. These assets were previously written down to estimated fair value, resulting in a $36.8 million impairment in fourth-quarter 2002 and an additional $41.7 million impairment in fourth-quarter 2003. In 2004, the fair value of the assets increased substantially due primarily to renegotiation of certain customer contracts and a general improvement in the market for processing assets. These operations were part of the Midstream segment.

Gulf Liquids New River Project LLC

During second-quarter 2003, our Board of Directors approved a plan authorizing management to negotiate and facilitate a sale of the assets of Gulf Liquids. The Gulf Liquids assets were written down to their estimated fair value less cost to sell resulting in a second-quarter 2003 impairment charge of $92.6 million, which is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. We estimated fair value based on a probability-weighted analysis of various scenarios, including expected sales prices, discounted cash flows and salvage valuations. During first-quarter 2004, we initiated a second bid process and expect the sale of these operations to be completed in the second half of 2004. These operations were part of the Midstream segment.

Winterthur International Insurance Company (Winterthur) issued policies to Gulf Liquids providing financial assurance related to construction contracts among Gulf Liquids, Gulsby Engineering, Inc. and Gulsby-Bay. After disputes arose regarding obligations under the construction contracts, Winterthur disputed coverage resulting in arbitration between Winterthur and Gulf Liquids. In July 2004, the arbitration panel awarded Gulf Liquids $93.6 million, offset by $18 million previously paid to Gulf Liquids, plus interest of $7.7 million, for a total award to Gulf Liquids of approximately $83.3 million. Winterthur has filed a Petition to Vacate the Arbitration Award in the New York State court.

Because the final outcome of the arbitration is uncertain, we have not recognized the award in the consolidated financial statements.

2004 COMPLETED TRANSACTIONS

Alaska refining, retail and pipeline operations

On March 31, 2004, we completed the sale of our Alaska refinery, retail and pipeline and related assets for approximately $304 million, subject to closing adjustments for items such as the value of petroleum inventories. We received $279 million in cash at the time of sale and $25 million in cash during the second quarter of 2004. Throughout the sales negotiation process, we regularly reassessed the estimated fair value of these assets based on information obtained from the sales negotiations using a probability-weighted approach. We recognized a $3.6 million gain on the sale during first-quarter 2004. The gain and an $8 million first-quarter 2003 impairment charge are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

2003 COMPLETED TRANSACTIONS

Canadian liquids operations

During the third quarter of 2003, we completed the sale of certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at our Redwater, Alberta plant for total proceeds of $246 million in cash. These operations were part of the Midstream segment.

Soda ash operations

On September 9, 2003, we completed the sale of our soda ash mining facility located in Colorado. During 2003, ongoing sale negotiations continued to provide new information regarding estimated fair value, and, as a result, the carrying value of these assets was adjusted periodically as necessary. We recognized impairment charges of $5 million and $11.1 million during the first and second quarters of 2003, respectively. These impairments are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. The soda ash operations were part of the previously reported International segment.

Williams Energy Partners

On June 17, 2003, we completed the sale of our 100 percent general partnership interest and 54.6 percent limited partner investment in Williams Energy Partners for approximately $512 million in cash and assumption by the purchasers of $570 million in debt. In December 2003, we received additional cash proceeds of $20 million following the occurrence of a contingent event. In second-quarter 2003 we recognized a gain on sale of $275.6 million which is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations and deferred an additional $113 million associated with certain environmental indemnifications we provided to the purchasers under the sales agreement. In second-quarter 2004, we settled these indemnifications with an agreement to pay $117.5 million over a four-year period (see Note 11).

Bio-energy facilities

On May 30, 2003, we completed the sale of our bio-energy operations for approximately $59 million in cash. During second-quarter 2003, we recognized a loss on sale of $6.4 million, which is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

Natural gas properties

On May 30, 2003, we completed the sale of natural gas exploration and production properties in the Raton Basin in southern Colorado and the Hugoton Embayment in southwestern Kansas. This sale included all of our interests within these basins. During second-quarter 2003, we recognized a gain on sale of $39.9 million which is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These properties were part of the Exploration & Production segment.

Texas Gas

On May 16, 2003, we completed the sale of Texas Gas Transmission Corporation for $795 million in cash and the assumption by the purchaser of $250 million in existing Texas Gas debt. There was no significant gain or loss recognized on the sale. We recorded a $109 million impairment charge in first-quarter 2003 reflecting the excess of the carrying cost of the long-lived assets over our estimate of fair value based on our assessment of the expected sales price pursuant to the purchase and sale agreement. The impairment charge is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. Texas Gas was a segment within Gas Pipeline.

Midsouth refinery and related assets

On March 4, 2003, we completed the sale of our refinery and other related operations located in Memphis, Tennessee for $455 million in cash. These assets were previously written down to their estimated fair value less cost to sell at December 31, 2002. We recognized a pre-tax gain on sale of $4.7 million in the first quarter of 2003. During the second quarter of 2003, we recognized a $24.7 million gain on the sale of an earn-out agreement we retained in the sale of the refinery. These gains are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

Williams travel centers

On February 27, 2003, we completed the sale of our travel centers for approximately $189 million in cash. We had previously written these assets down to their estimated fair value to sell at December 31, 2002, and did not recognize a significant gain or loss on the sale. These operations were part of the previously reported Petroleum Services segment.

7. EARNINGS (LOSS) PER SHARE

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

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS; SHARES IN THOUSANDS)		(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS; SHARES IN THOUSANDS)	
Income (loss) from continuing operations	$ (18.0)	$ 113.7	$ (19.5)	$ 70.6
Convertible preferred stock dividends	--	(22.7)	--	(29.5)
Income (loss) from continuing operations available to common stockholders for basic and diluted earnings per share	$ (18.0)	$ 91.0	$ (19.5)	$ 41.1
Basic weighted-average shares	521,698	518,090	520,592	517,872
Effect of dilutive securities:				
Stock options	--	3,889	--	2,814
Deferred shares unvested	--	2,567	--	2,867
Convertible debentures	--	10,293	--	--
Diluted weighted-average shares	521,698	534,839	520,592	523,553
Earnings (loss) per share from continuing operations:				
Basic	$ (.03)	$ .18	$ (.04)	$ .08
Diluted	$ (.03)	$ .17	$ (.04)	$ .07

For the three and six months ended June 30, 2004, approximately 3.5 million and 3.7 million weighted-average stock options, respectively, and approximately 2.8 million and 2.6 million weighted-average unvested deferred shares, respectively, that otherwise would have been included, have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive. The unvested deferred shares will vest over the period from July 2004 to January 2008.

In addition, for the three and six months ended June 30, 2004, approximately 27.5 million weighted-average shares related to the assumed conversion of convertible debentures, as well as the related interest, have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive. If no other components used to calculate diluted earnings per share (EPS) change, we estimate the assumed conversion of the convertible debentures would become dilutive and therefore be included in diluted EPS at an Income from continuing operations amount of $48.8 million and $97.4 million for the three and six months ended June 30, 2004, respectively.

Approximately 9.4 million options to purchase shares of common stock with a weighted-average exercise price of $27.43 were outstanding at June 30, 2004, but have been excluded from the computation of diluted earnings per share. Inclusion of these shares would have been antidilutive, as the exercise prices of the options exceeded the second-quarter weighted average market price of the common shares of $11.03 for the three months ended June 30, 2004.

For the three and six months ended June 30, 2003, approximately 11.3 million and 13 million weighted-average shares, respectively, related to the assumed conversion of 9 7/8 percent cumulative convertible preferred stock have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive. The preferred stock was redeemed in June 2003.

For the six months ended June 30, 2003, approximately 5.2 million weighted-average shares related to the assumed conversion of convertible debentures, as well as the related interest, were excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive. If no other components used to calculate diluted EPS change, we estimate the assumed conversion of the convertible debentures would become dilutive and therefore be included in diluted EPS at an Income from continuing operations amount of $148.4 million.

8. EMPLOYEE BENEFIT PLANS

Net periodic pension and other postretirement benefit (income) expense for the three and six months ended June 30, 2004 and 2003 is as follows:

	PENSION BENEFITS			
	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
Components of net periodic pension (income) expense:				
Service cost	$ 5.1	$ 6.4	$ 12.1	$ 12.9
Interest cost	10.7	13.2	25.2	26.6
Expected return on plan assets	(17.5)	(13.6)	(32.4)	(27.4)
Amortization of prior service credit	(.1)	(.6)	(.8)	(1.2)
Recognized net actuarial loss	.9	3.4	4.6	6.8
Regulatory asset amortization (deferral)	(.1)	.1	1.0	.2
Settlement/curtailment (income) expense	.1	(.9)	.1	.6
Net periodic pension (income) expense	$ (.9)	$ 8.0	$ 9.8	$ 18.5

	OTHER POSTRETIREMENT BENEFITS			
	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
Components of net periodic postretirement benefit (income) expense:				
Service cost	$ .3	$ 1.5	$ 1.8	$ 3.2
Interest cost	5.1	6.3	10.8	12.7
Expected return on plan assets	(3.1)	(3.3)	(6.2)	(6.8)
Amortization of transition obligation	.7	.7	1.3	1.4
Amortization of prior service cost	.1	.1	.3	.3
Regulatory asset amortization	1.9	2.0	3.5	4.7
Settlement/curtailment (income) expense	--	(29.0)	--	(29.0)
Net periodic postretirement benefit (income) expense	$ 5.0	$ (21.7)	$ 11.5	$ (13.5)

The $29 million settlement/curtailment income included in net periodic postretirement (income) expense for the three and six months ended June 30, 2003, is included in income (loss) from discontinued operations in the Consolidated Statement of Operations due to the settlement/curtailment directly resulting from the sale of the operations included within discontinued operations.

As previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2003, we expected to contribute approximately $60 million to our pension plans and approximately $15 million to our other postretirement benefit plans in 2004. For the six months ended June 30, 2004, we contributed $16.5 million to our pension plans and $5.8 million to our other postretirement benefit plans. We presently anticipate contributing approximately an additional $44 million to fund our pension plans in 2004 for a total of approximately $61 million. We presently anticipate contributing approximately an additional $9 million to our other postretirement benefit plans in 2004 for a total of approximately $15 million.

Net periodic pension income for the three months ended June 30, 2004 includes a favorable adjustment to reflect revised 2004 actuarial information. The improvement results largely from a reduction in the number of employees and higher than expected asset performance.

Notes (Continued)

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act introduces a prescription drug benefit under Medicare (Medicare Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Our health care plan for retirees includes prescription drug coverage. In accordance with FASB Staff Position (FSP) No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," the provisions of the Act are not reflected in any measures of benefit obligations or other postretirement benefit expense in the financial statements or accompanying notes. In May 2004, the FASB issued FSP No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." This guidance is effective for us beginning in third quarter 2004 and supersedes FSP No. FAS 106-1. We are evaluating the impact of the Act on future obligations of the plan. If the plan is determined to be actuarially equivalent and eligible for the subsidy, the change in the obligation attributable to prior service will be deferred and recognized over future periods beginning in third quarter 2004.

9. STOCK-BASED COMPENSATION

Employee stock-based awards are accounted for under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25) and related interpretations. Fixed-plan common stock options generally do not result in compensation expense because the exercise price of the stock options equals the market price of the underlying stock on the date of grant. The following table illustrates the effect on net income (loss) and earnings (loss) per share if we had applied the fair value recognition provisions of SFAS No. 123 "Accounting for Stock-Based Compensation."

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
Net income (loss), as reported	$ (18.2)	$ 269.7	$ (8.3)	$ (544.8)
Add: Stock-based employee compensation included in the Consolidated Statement of Operations, net of related tax effects	1.3	3.3	5.8	13.9
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(3.2)	(6.3)	(10.7)	(21.0)
Pro forma net income (loss)	$ (20.1)	$ 266.7	$ (13.2)	$ (551.9)
Earnings (loss) per share:				
Basic-as reported	$ (.03)	$ .48	$ (.02)	$ (1.11)
Basic-pro forma	$ (.04)	$ .47	$ (.03)	$ (1.12)
Diluted-as reported	$ (.03)	$ .46	$ (.02)	$ (1.10)
Diluted-pro forma	$ (.04)	$ .46	$ (.03)	$ (1.11)

Pro forma amounts for 2004 include compensation expense from awards of our company stock made in 2004, 2003, 2002 and 2001. Also included in pro forma expense for the three and six months ended June 30, 2004, is $700,000 and $1.7 million, respectively, of incremental expense associated with the stock option exchange program described below. Pro forma amounts for 2003 include compensation expense from awards made in 2003, 2002 and 2001.

Since compensation expense for stock options is recognized over the future years' vesting period for pro forma disclosure purposes and additional awards are generally made each year, pro forma amounts may not be representative of future years' amounts.

On May 15, 2003, our shareholders approved a stock option exchange program. Under this exchange program, eligible employees were given a one-time opportunity to exchange certain outstanding options for a proportionately lesser number of options at an exercise price to be determined at the grant date of the new options. Surrendered options were cancelled June 26, 2003, and replacement options were granted on December 29, 2003. We did not recognize any expense pursuant to the stock option exchange. However, for purposes of pro forma disclosures, we recognized additional expense related to these new options and will amortize the remaining expense on the cancelled options through year-end 2004.

10. INVENTORIES

Inventories at June 30, 2004 and December 31, 2003 are as follows:

	JUNE 30, 2004	DECEMBER 31, 2003
	(MILLIONS)	
Finished goods:		
Refined products	$ 15.8	$ 8.0
Natural gas liquids	60.1	40.4
	75.9	48.4
Natural gas in underground storage	116.8	132.5
Materials, supplies and other	62.6	62.0
	$ 255.3	$ 242.9

11. ACCRUED LIABILITIES AND OTHER LIABILITIES AND DEFERRED INCOME

On May 26, 2004, we were released from certain historical indemnities, primarily related to environmental remediation, for an agreement to pay $117.5 million (see Note 13). We had previously deferred $113 million of a gain on sale related to these indemnities. At the date of sale, the deferred revenue and identified obligations related to the indemnities totaled $102 million. At June 30, 2004, the net present value of this settlement is $107.5 million. Of this amount, $35 million is classified as current and was subsequently paid on July 1, 2004. The remaining amount will be paid in three installments of $27.5 million, $20 million, and $35 million in 2005, 2006, and 2007, respectively.

12. DEBT AND BANKING ARRANGEMENTS

NOTES PAYABLE AND LONG-TERM DEBT

Notes payable and long-term debt at June 30, 2004 and December 31, 2003, are as follows:

	WEIGHTED-AVERAGE INTEREST RATE (1)	JUNE 30, 2004	DECEMBER 31, 2003
		(MILLIONS)	
Secured notes payable	--%	$ --	$ 3.3
Long-term debt:			
Secured long-term debt			
Notes, 6.62%-9.45%, payable through 2016	8.0%	$ 231.7	$ 243.7
Notes, adjustable rate, payable through 2016	3.4%	594.9	602.5
Unsecured long-term debt			
Debentures, 5.5%-10.25%, payable through 2033	7.1%	1,415.5	1,645.2
Notes, 6.125%-9.25%, payable through 2032 (2)	7.7%	7,517.1	9,404.3
Other, payable through 2007	6.0%	.4	79.3
		9,759.6	11,975.0
Long-term debt due within one year		(276.6)	(935.2)
Total long-term debt		$ 9,483.0	$ 11,039.8

(1) At June 30, 2004.

(2) Includes $1.1 billion of 6.5 percent notes payable 2007, subject to remarketing in November 2004, discussed below.

Long-term debt includes $1.1 billion of 6.5 percent notes, payable in 2007, which are subject to remarketing in November 2004. These FELINE PACS include equity forward contracts that require the holder to purchase shares of our common stock in February 2005. If a remarketing is unsuccessful in 2004 and a second remarketing in February 2005 is unsuccessful as defined in the offering document for the FELINE PACS, then we could exercise our right to foreclose on the notes in order to satisfy the obligation of the holders of the equity forward contracts requiring the holder to purchase our common stock. This would be a non-cash transaction. If either remarketing of the notes is successful, we will receive the proceeds from the remarketing in February 2005 and issue stock to the holders of the forward contracts.

On February 25, 2004, our Exploration & Production segment amended its $500 million secured variable rate note. The amendment reduced the floating interest rate from the London InterBank Offered Rate (LIBOR) plus 3.75 percent to LIBOR plus 2.5 percent. The amendment also extended the maturity date from May 30, 2007 to May 30, 2008. The amendment provides for an additional reduction in the interest rate by 25 basis points, or 0.25 percent, if we meet certain credit-rating requirements. The significant covenants were not altered by the amendment.

In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of a specified series of our outstanding notes and debentures. As of the June 8, 2004, tender offer expiration date, we had accepted for purchase tenders of notes and debentures with an aggregate principal amount of approximately $1.17 billion. Holders of notes and debentures tendered by the early tender expiration date received an early tender payment premium of $30.00 per $1,000.00 principal amount of notes and debentures. In May 2004, we also repurchased approximately $255 million of various notes with maturity dates ranging from 2006 to 2011. In conjunction with these tendered notes and debentures and related consents, and early retirements, we paid premiums of approximately $79 million. The premiums, as well as related fees and expenses, together totaling approximately $96.8 million, were recorded in second-quarter 2004 as early debt retirement costs.

On July 20, 2004, Wilpro Energy Services (PIGAP II) Limited, one of our subsidiaries, received a notice of default from the Venezuelan state oil company, PDVSA, relating to certain operational issues alleging that our subsidiary is not in compliance under a services agreement. We do not believe a basis exists for such notice and are contesting the giving of this notice. Although this notice of default could result in an event of default with respect to project loans totaling approximately $219 million and could result in an adverse effect with respect to other of our debt instruments, we believe that we will be able to resolve any issues arising from the alleged notice of default without any such results occurring with respect to our other debt instruments. The lenders under the project loan agreement have confirmed to us in writing that based on the facts they currently know, they have no intention of exercising any rights or remedies under the project loan agreement until the issues raised in the notice and our response are clarified.

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, 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.

Revolving credit and letter of credit facilities

In April 2004, we entered into two unsecured bank revolving credit facilities totaling $500 million. These facilities provide for both borrowings and issuing letters of credit, but are used primarily for issuing letters of credit. At June 30, 2004, letters of credit totaling $489 million have been issued by the participating financial institution under this facility and no revolving credit loans were outstanding. We are required to pay to the bank fixed fees at a weighted-average rate of 3.64 percent on the total committed amount of the facilities. In addition, we pay interest on any borrowings at a fluctuating rate comprised of either a base rate or LIBOR. We were able to obtain the unsecured credit facilities because the funding bank syndicated its associated credit risk into the institutional investor market via a 144A offering, which allows for the resale of certain restricted securities to qualified institutional buyers. Upon the occurrence of certain credit events, letters of credit outstanding under the agreement become cash collateralized creating a borrowing under the facilities. Concurrently the bank can deliver the facilities to the institutional investors, whereby the investors replace the bank as lender under the facilities. Upon such occurrence, we will pay:

- a fixed facility fee at a weighted average rate of 3.19 percent to the investors,
- interest on borrowings under the $400 million facility equal to a fixed rate of 3.57 percent, and
- interest on borrowings under the $100 million facility at a fluctuating LIBOR interest rate.

To facilitate the syndication of these facilities, the bank established trusts funded by the institutional investors. The assets of the trusts serve as collateral to reimburse the bank for our borrowings in the event the facilities are delivered to the investors. Thus, we have no asset securitization or collateral requirements under the new facilities. During second-quarter 2004, use of these new facilities replaced existing facilities and released approximately $500 million of restricted cash, restricted investments and margin deposits which secured our previous $800 million revolving and letter of credit facility. Significant covenants under these new facilities include the following:

- limitations on certain payments, including a limitation on the payment of quarterly dividends to no greater than $.05 per common share (however, we are limited to $.02 per common share under a more restrictive covenant contained in our $800 million 8.625 percent senior unsecured notes);
- limitations on asset sales;
- limitations on the use of proceeds from permitted asset sales;
- limitations on transactions with affiliates; and
- limitations on the incurrence of additional indebtedness and issuance of disqualified stock, unless the fixed charge coverage ratio for our most recently ended four full fiscal quarters is at least 2 to 1, determined on a proforma basis.

On May 3, 2004, we entered into a new three-year, $1 billion secured revolving credit facility which is available for borrowings and letters of credit. At June 30, 2004, letters of credit totaling $181 million have been issued by the participating institutions under this facility and no revolving credit loans were outstanding. We also have a commitment from our agent bank to expand our credit facility by an additional $275 million. Northwest Pipeline Corporation (Northwest) and Transcontinental Gas Pipeline Corporation (Transco) have access to $400 million each under the facility. The new facility is secured by certain Midstream assets, including substantially all of our southwest Wyoming, Wamsutter, San Juan Conventional, Manzanares and Torre Alta systems. Additionally, the facility is guaranteed by WGP. Interest is calculated based on a choice of two methods: a fluctuating rate equal to the facilitating bank's base rate plus an applicable margin or a periodic fixed rate equal to LIBOR plus an applicable margin. We are also required to pay a commitment fee based on the unused portion of the facility, currently .375 percent. The applicable margins and commitment fee are based on the relevant borrower's senior unsecured long-term debt ratings. Significant financial covenants under the credit agreement include:

- ratio of debt to capitalization no greater than (i) 75 percent for the period June 30, 2004 through December 31, 2004, (ii) 70 percent for the period after December 31, 2004 through December 31, 2005, and (iii) 65 percent for the remaining term of the agreement;

- ratio of debt to capitalization no greater than 55 percent for Northwest and Transco; and

- ratio of EBITDA to Interest, on a rolling four quarter basis (or, in the first year, building up to a rolling four quarter basis), no less than (i) 1.5 for the periods ending September 30, 2004 through March 31, 2005, (ii) 2.0 for any period after March 31, 2005 through December 31, 2005, and (iii) 2.5 for the remaining term of the agreement.

Upon entering into the new $1 billion secured revolving credit facility on May 3, 2004, we terminated the $800 million revolving and letter of credit facility which we entered into in June 2003. Termination of the facility resulted in a $3.8 million charge which is recorded in Interest accrued in the Consolidated Statement of Operations.

Retirements

On March 15, 2004, we retired $679 million of senior, unsecured 9.25 percent notes. The amount represented the outstanding balance subsequent to the fourth-quarter 2003 tender which retired $721 million of the original $1.4 billion balance.

As previously discussed, in May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of our specified series of outstanding notes. We accepted for purchase tenders of notes and debentures with an aggregate principal amount of approximately $1.17 billion. In May 2004, we also repurchased approximately $255 million of various notes with maturity dates ranging from 2006 to 2011.

A summary of significant retirements, payments, prepayments and tenders of long-term debt for the six months ended June 30, 2004 is as follows:

Issue/Terms	DUE DATE	PRINCIPAL AMOUNT (MILLIONS)
9.25% senior unsecured notes	2004	$ 678.5
6.75% PATS	2006	370.3
6.5% unsecured notes	2006	251.4
6.25% unsecured debentures	2006	231.0
6.5% unsecured notes	2008	221.9
7.55% unsecured notes	2007	118.8
6.625% unsecured notes	2004	101.6
7.25% unsecured notes	2009	85.0
Long-term debt collateralized by certain receivables	N/A	78.7
7.125% unsecured notes	2011	60.0
Various notes, 6.62% - 9.45%	2013-2016	12.0
Various notes, adjustable rate	2004-2016	7.6

13. CONTINGENT LIABILITIES AND COMMITMENTS

RATE AND REGULATORY MATTERS AND RELATED LITIGATION

Our interstate pipeline subsidiaries have various regulatory proceedings pending. As a result of rulings in certain of these proceedings, a portion of the revenues of these subsidiaries has been collected subject to refund. The natural gas pipeline subsidiaries have accrued approximately $7 million for potential refund as of June 30, 2004.

ISSUES RESULTING FROM CALIFORNIA ENERGY CRISIS

Power subsidiaries are 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 have been challenged in various proceedings including those before the Federal Energy Regulatory Commission (FERC). These challenges include refund proceedings, California Independent System Operator (ISO) fines, 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 a settlement with the State of California and others that has resolved each of these issues as to the State, and in February 2004 we announced a settlement with certain California utilities that resolves these issues as to such utilities. However, certain of these issues remain open as to the FERC and other non-settling parties.

Refund proceedings

We and other suppliers of electricity in the California market are the subject of refund proceedings before the FERC. In December 2000, the FERC issued an order initiating the proceeding, which ultimately (by order dated June 19, 2001) established a refund methodology and set a refund period of October 2, 2000 to June 19, 2001. As a result of a hearing to determine refund liability for the market participants, a FERC administrative law judge issued findings on December 12, 2002, that estimated our refund obligation to the ISO at $192 million, excluding emissions costs and interest. The judge estimated that our refund obligation to the California Power Exchange (PX) was $21.5 million, excluding interest. However, the judge estimated that the ISO owes us $246.8 million, excluding interest, and that the PX owes us $17.4 million, excluding interest, and $2.9 million in charge backs. The estimates did not include $17 million in emissions costs that the judge found we are entitled to use as an offset to the refund liability, and the judge's refund estimates are not based on final mitigated market clearing prices. On March 26, 2003, the FERC acted to largely adopt the judge's order with a change to the gas methodology used to set the clearing price. As a result, Power recorded a first-quarter 2003 charge for refund obligations of $37 million. Net interest income related to amounts due from the counterparties is approximately $31 million through June 30, 2004. On October 16, 2003, the FERC issued an additional refund order granting rehearing in part and denying rehearing in part. This order is not expected to have a material effect on the refund calculation for us. However, pursuant to the October 16 order, the ISO has been ordered to calculate refunds for the market. This study is expected to be complete in 2004.

On February 25, 2004, we announced a settlement agreement with California utilities, Southern California Edison and Pacific Gas & Electric (PG&E), to resolve our refund liability to the utilities as well as all other known disputes related to the California energy crisis of 2000 and 2001 (the "Utility Settlement"). We recorded a charge of approximately $33 million in the fourth quarter of 2003 associated with the terms of this settlement. San Diego Gas and Electric also joined in the settlement as a party. The Utility Settlement was filed with the FERC on April 27, 2004 and was approved by the FERC on July 2, 2004 to be effective on July 12, 2004. While only these three utilities were originally parties to the Utility Settlement with us, additional parties have now opted in and the Utility Settlement includes funding for refunds to all buyers in equal kind in the FERC refund period. Should any buyer not opt into the Utility Settlement, the refund amount in the Utility Settlement would be reduced and we would continue to litigate with that buyer regarding the refund issue and amount. Pursuant to this settlement our outstanding receivables for the period of approximately $261 million will be partially offset by our settlement obligation of approximately $136 million. We have received $2 million of our net receivable in the second quarter. During July, we received approximately $104 million of our remaining net $123 million receivable. Approximately the same amount of funds ($109 million) was used on June 24, 2004 to repurchase PG&E receivables previously sold to Bear Stearns. As for the $19 million receivable that remains at the end of July, $16 million is being held in escrow until released by the FERC and $3 million is being held by the PX. Approval by the FERC also resolved FERC investigations into physical and economic withholding. The Utility Settlement also resolved any claims by the settling parties regarding these issues.

In a separate but related proceeding, certain entities have also asked the FERC to revoke our authority to sell power from California-based generating units at market-based rates, to limit us to cost-based rates for future sales from such units and to order refunds of excessive rates, with interest, retroactive to May 1, 2000, and possibly earlier. As a result of the Utility Settlement, this issue is resolved and we will maintain all existing authorities.

Although we have entered into a global settlement with the State of California, certain California utilities, and various other parties that resolve the refund issues among the settling parties, we have potential refund exposure to non-settling parties (e.g., various California end users that have not agreed to opt into the utility settlement). Therefore, we continue to participate in the FERC refund case and related proceedings. Challenges to virtually every aspect of the refund proceeding, including the refund period, are now pending at the Ninth Circuit Court of Appeals. No schedule has yet been established for hearing the appeals.

ISO fines

On July 3, 2002, the ISO announced fines against several energy producers including us, for failure to deliver electricity during the period December 2000 through May 2001. The ISO fined us $25.5 million during this period, which was offset against our claims for payment from the ISO. These amounts will be adjusted as part of the refund proceeding described above. As the result of a settlement reached with the ISO pursuant to a FERC-approved dispute resolution process contained in the ISO tariff, these fines will be significantly reduced through the re-run of the market that takes place in the refund proceeding.

Summer 2002 90-day contracts

On May 2, 2002, PacifiCorp filed a complaint with the FERC against Power seeking relief from rates contained in three separate confirmation agreements between PacifiCorp and Power (known as the Summer 2002 90-Day Contracts). PacifiCorp filed similar complaints against three other suppliers. PacifiCorp alleged that the rates contained in the contracts are unjust and unreasonable. On June 26, 2003, the FERC affirmed the administrative law judge's initial decision dismissing the complaints. PacifiCorp has appealed the FERC's order to the United States Court of Appeals for the DC Circuit after the FERC denied rehearing of its order on November 10, 2003.

Investigations of alleged market manipulation

As a result of various allegations and FERC Orders, in 2002 the FERC initiated investigations of manipulation of the California gas and power markets. As they related to us, these investigations included economic and physical withholding, so-called "Enron Gaming Practices" and gas index manipulation.

On February 13, 2002, the FERC issued an Order Directing Staff Investigation commencing a proceeding titled Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices prior to the California parties (who include the California Attorney General, the Electricity Oversight Board, the Public Utilities Commission and two investor-owned utilities) filing of their report. Through the investigation, the FERC intends to determine whether "any entity, including Enron Corporation (Enron) (through any of its affiliates or subsidiaries), manipulated short-term prices for electric energy or natural gas in the West or otherwise exercised undue influence over wholesale electric prices in the West since January 1, 2000, resulting in potentially unjust and unreasonable rates in long-term power sales contracts subsequently entered into by sellers in the West." On May 8, 2002, we received data requests from the FERC related to a disclosure by Enron of certain trading practices in which it may have been engaged in the California market. On May 21, and May 22, 2002, the FERC supplemented the request inquiring as to "wash" or "round-trip" transactions. We responded on May 22, 2002, May 31, 2002, and June 5, 2002, to the data requests. On June 4, 2002, the FERC issued an order to us to show cause why our market-based rate authority should not be revoked as the FERC found that certain of our responses related to the Enron trading practices constituted a failure to cooperate with the staff's investigation. We subsequently supplemented our responses to address the show cause order. On July 26, 2002, we received a letter from the FERC informing us that it had reviewed all of our supplemental responses and concluded that we responded to the initial May 8, 2002 request.

As also discussed below in REPORTING OF NATURAL GAS-RELATED INFORMATION TO TRADE PUBLICATIONS, on November 8, 2002, we received a subpoena from a federal grand jury in Northern California seeking documents related to our involvement in California markets. We have completed our response to the subpoena. This subpoena is a part of the broad United States Department of Justice (DOJ) investigation regarding gas and power trading.

Pursuant to an order from the Ninth Circuit, the FERC permitted certain California parties to conduct additional discovery into market manipulation by sellers in the California markets. The California parties sought this discovery in order to potentially expand the scope of the refunds. On March 3, 2003, the California parties submitted evidence from this discovery on market manipulation ("March 3rd Report"). We and other sellers submitted comments regarding the additional evidence on March 20, 2003.

On March 26, 2003, the FERC issued a Staff Report addressing: (1) Enron trading practices, (2) an allegation in a June 2, 2002 New York Times article that we had attempted to corner the gas market, and (3) the allegations of gas price index manipulation which are discussed in more detail below in REPORTING OF NATURAL GAS-RELATED INFORMATION TO TRADE PUBLICATIONS. The Staff Report cleared us on the issue of cornering the market and contemplated or established further proceedings on the other two issues as to us and numerous other market participants. On June 25, 2003, the FERC issued a series of orders in response to the California parties' March 3rd Report and the Staff Report. These orders resulted in further investigations regarding potential allegations of physical withholding, economic withholding, and a show cause order alleging that various companies engaged in Enron trading practices. On August 29, 2003, we entered into a settlement with the FERC trial staff of all Enron trading practices for approximately $45,000. The settlement was approved by the FERC on January 22, 2004. The investigations of physical and economic withholding are also continuing. Each of these FERC investigations of alleged market manipulation are resolved pursuant to the Utility Settlement that is discussed above in Refund proceedings.

Long-term contracts

In February 2001, during the height of the California energy crisis, we entered into a long-term power contract with the State of California to assist in stabilizing its market. This contract was later challenged by the State of California. This challenge resulted in settlement discussions being held between the State and us on the contract issue as well as other state initiated proceedings and allegations of market manipulation. A settlement was reached that resulted in us entering into a settlement agreement with the State of California and other non-Federal parties that includes renegotiated long-term energy contracts. These contracts are made up of block energy sales, dispatchable products and a gas contract. The settlement does not extend to criminal matters or matters of willful fraud, but also resolved civil complaints brought by the California Attorney General against us and the State of California's refund claims that are discussed above. In addition, the settlement resolved ongoing investigations by the States of California, Oregon and Washington. The settlement was reduced to writing and executed on November 11, 2002. The settlement closed on December 31, 2002, after FERC issued an order granting our motion for partial dismissal from the refund proceedings. The dismissal affects our refund obligations to the settling parties, but not to other parties, such as investor-owned utilities. Pursuant to the settlement, the California Public Utilities Commission (CPUC) and California Electricity Oversight Board (CEOB) filed a motion on January 13, 2003 to withdraw their complaints against us regarding the original block energy sales contract. On June 26, 2003, the FERC granted the CPUC and CEOB joint motion to withdraw their respective complaints against us. Certain private class action and other civil plaintiffs who have initiated class action litigation against us and others in California based on allegations against us with respect to the California energy crisis also executed the settlement. Final approval by the court is needed to make the settlement effective as to plaintiffs and to terminate the class actions as to us. The Court granted approval on June 29, 2004. Some litigation by non-California plaintiffs, or relating to reporting of natural gas information to trade publications, as discussed below, will continue. As of June 30, 2004, pursuant to the terms of the settlement, we have transferred ownership of six LM6000 gas powered electric turbines, have made two payments totaling $72 million to the California Attorney General, and have funded a $15 million fee and expense fund associated with civil actions that are subject to the settlement. An additional $75 million remains to be paid to the California Attorney General (or his designee) over the next six years, with the final payment of $15 million due on January 1, 2010.

REPORTING OF NATURAL GAS-RELATED INFORMATION TO TRADE PUBLICATIONS

We disclosed on October 25, 2002, that certain of our natural gas traders had reported inaccurate information to a trade publication that published gas price indices. As noted above, on November 8, 2002, we received a subpoena from a federal grand jury in Northern California seeking documents related to our involvement in California markets, including our reporting to trade publications for both gas and power transactions. We completed our response to the subpoena. The DOJ's investigation into this matter is continuing. In addition, the Commodity Futures Trading Commission (CFTC) has conducted an investigation of us regarding this issue. On July 29, 2003, we reached a settlement with the CFTC where in exchange for $20 million, the CFTC closed its investigation and we did not admit or deny allegations that we had engaged in false reporting or attempted manipulation. Civil suits based on allegations of manipulating the gas indices have been brought against us and others in Federal court in New York, Washington, Oregon and California and in state court in California.

Investigations related to natural gas storage inventory

We responded to a subpoena from the CFTC and inquiries from the FERC related to natural gas storage inventory issues. We believe that these inquiries are a part of an ongoing general industry-wide investigation. The inquiries relate to the formal reporting of inventory levels, the sharing of non-public data concerning inventory levels, and the potential uses of such data in natural gas trading. Through some of our subsidiaries, we own and operate natural gas storage facilities.

MOBILE BAY EXPANSION

On December 3, 2002, an administrative law judge at the FERC issued an initial decision in Transco's 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. The administrative law judge's initial decision is subject to review by the FERC. On March 26, 2004, the FERC issued an Order on Initial Decision in which it reversed the administrative law judge's holding and accepted Transco's proposal for rolled in rates. Power holds long-term transportation capacity on the Mobile Bay expansion project. If the FERC had adopted the decision of the administrative law judge on the pricing of the Mobile Bay expansion project and also required that the decision be implemented effective September 1, 2001, Power could have been subject to surcharges of approximately $50 million, excluding interest, through June 30, 2004, in addition to increased costs going forward. On April 26, 2004, several parties, including Transco filed requests for rehearing of the FERC's March 26, 2004 order.

ENRON BANKRUPTCY

We have outstanding claims against Enron Corp. and various of its subsidiaries (collectively "Enron") related to Enron's bankruptcy filed in December 2001. In March 2002, we sold $100 million of our claims against Enron to a third party for $24.5 million. On December 23, 2003, Enron filed objections to these claims. Under the sales agreement, the purchaser of the claims may demand repayment of the purchase price, plus interest assessed at 7.5 percent per annum, for that portion of the claims still subject to objections 90 days following the initial objection. To date, the purchaser has not demanded repayment.

ENVIRONMENTAL MATTERS

Continuing operations

Since 1989, our Transco subsidiary has had studies under way 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 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 U.S. Environmental Protection Agency (EPA) and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other programs 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 June 30, 2004, Transco had accrued liabilities of $27 million related to PCB contamination, potential mercury contamination, and other toxic and hazardous substances.

We also accrued environmental remediation costs for our natural gas gathering and processing facilities, primarily related to soil and groundwater contamination. At June 30, 2004, we had accrued liabilities totaling approximately $8 million for these costs.

Actual costs incurred for these matters will depend on the actual number of contaminated sites identified, the amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors.

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.

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 June 30, 2004, we had accrued liabilities of approximately $10 million for such excess costs.

We are also in discussions with defendants involved in two class action damages lawsuits involving this former chemical fertilizer business. We are not a named defendant in the lawsuits, but have contractual obligations to participate with the named defendants in the ongoing remediation. One named defendant has filed a motion to compel us to participate in arbitration over the contractual obligations.

WILLIAMS ENERGY PARTNERS

As part of our June 17, 2003 sale of Williams Energy Partners (see Note 6), we indemnified the purchaser for:

(1) environmental cleanup costs resulting from certain conditions, primarily soil and groundwater contamination, at specified locations, to the extent such costs exceed a specified amount and

(2) currently unidentified environmental contamination relating to operations prior to April 2002 and identified prior to April 2008.

On May 26, 2004, the parties reached an agreement for buyout of certain indemnities in the form of a structured cash settlement totaling $117.5 million. Yearly payments will be made through 2007. The agreement releases Williams from all environmental indemnity obligations under the June 2003 Sale of Williams Energy Partners and two related agreements. Williams is now indemnified by the purchaser for third party environmental claims made against Williams for claims covered under the June 2003 purchase and sale agreement (PSA) and related agreements as well as all environmental occurrences before the closing date of the PSA. The agreement also transferred most third party litigation matters related to Williams Energy Partners' assets to the purchaser.

On July 2, 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from our pipelines, pipeline systems, and pipeline facilities used in the movement of oil or petroleum products, during the period from July 1, 1998 through July 2, 2001. In November 2001, we furnished our response. This matter has not become an enforcement proceeding. On March 11, 2004, the Department of Justice (DOJ) invited the new owner of the Williams Pipe Line, Magellan Midstream Partners, L.P. (Magellan), to enter into negotiations regarding alleged violations of the Clean Water Act and to sign a tolling agreement. No penalty has been assessed by the EPA; however, the DOJ stated in its letter that the maximum possible penalties were approximately $22 million for the alleged violations. It is anticipated that by providing additional clarification and through negotiations with the EPA and DOJ, that any proposed penalty will be reduced. All environmental indemnity obligations to Magellan were released in the May 26, 2004 buyout agreement described above. Williams will participate in the EPA/DOJ negotiations and respond to requests for information related to three release events not related to Magellan-owned assets.

OTHER

At June 30, 2004, we had accrued environmental liabilities totaling approximately $16 million related primarily to our:

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

- former propane marketing operations, petroleum products and natural gas pipelines;

- a discontinued petroleum refining facility; and

- exploration and production and mining operations.

These costs include (1) certain conditions at specified locations related primarily to soil and groundwater contamination and (2) any penalty assessed on Williams Refining & Marketing, LLC (Williams Refining) associated with noncompliance with EPA's benzene waste "NESHAP" regulations. In 2002, Williams Refining submitted to the EPA a self-disclosure letter indicating noncompliance with those regulations. This unintentional noncompliance had occurred due to a regulatory interpretation that resulted in under-counting the total annual benzene level at Williams Refining Memphis refinery. Also in 2002, the EPA conducted an all-media audit of the Memphis refinery. The EPA anticipates releasing a report of its audit findings in 2004. The EPA will likely assess a penalty on Williams Refining due to the benzene waste NESHAP issue, but the amount of any such penalty is not known. In connection with the sale of the Memphis refinery in March 2003, we indemnified the purchaser for any such penalty.

We are a plaintiff in litigation involving the environmental investigation and subsequent cleanup of our former retail petroleum and refining operations. In April we received a court order to participate in mediation before the end of June with the defendant to attempt to reach a settlement prior to going to trial. Mediation occurred in June and discussions are ongoing.

Certain of our subsidiaries have been identified as potentially responsible parties (PRP) 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.

OTHER LEGAL MATTERS

Royalty indemnifications

In connection with agreements 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 which the producers may be required to pay as a result of such settlements. Transco, through its agent, Power, 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 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.

As a result of these settlements, Transco has been sued by certain producers seeking indemnification from Transco. Transco is currently a defendant in one lawsuit in which a producer has asserted damages, including interest calculated through June 30, 2004, of approximately $10 million. On July 11, 2003, at the conclusion of the trial, the judge ruled in Transco's favor and subsequently entered a formal judgment. The plaintiff is seeking an appeal.

Will Price (formerly Quinque)

On June 8, 2001, fourteen of our entities were named as defendants in a nationwide class action lawsuit which had been pending against other defendants, generally pipeline and gathering companies, for more than one year. The plaintiffs allege that the defendants, including us, 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. After the court denied class action certification and while motions to dismiss for lack of personal jurisdiction were pending, the court granted the plaintiffs' motion to amend their petition on July 29, 2003. The fourth amended petition, which was filed on July 29, 2003, deletes all of our defendants except two Midstream subsidiaries. All defendants intend to continue their opposition to class certification.

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 sale of Kern River and Texas Gas, 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. The amounts accrued for these indemnifications are insignificant. Grynberg has 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. On April 9, 1999, the DOJ announced that it was declining to intervene in any of the Grynberg qui tam cases, including the action filed in federal court in Colorado against us. On October 21, 1999, the Panel on Multi-District Litigation transferred all of the Grynberg qui tam cases, including those filed against us, to the federal court in Wyoming for pre-trial purposes. Grynberg's measurement claims remain pending against us and the other defendants; the court previously dismissed Grynberg's royalty valuation claims.

On August 6, 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 Williams Production RMT Company with a complaint in the state court in Denver, Colorado. The complaint alleges that the defendants have used mismeasurement techniques that distort the BTU 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 defendants inappropriately took deductions from the gross value of their natural gas and made other royalty valuation errors. Theories for relief include breach of contract, breach of implied covenant of good faith and fair dealing, anticipatory repudiation, declaratory relief, equitable accounting, civil theft, deceptive trade practices, negligent misrepresentation, deceit based on fraud, conversion, breach of fiduciary duty, and violations of the state racketeering statute. 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 $1.4 million dollars. Our motion to stay the proceedings in this case based on the pendency of the False Claims Act litigation discussed in the preceding paragraph was granted on January 15, 2003.

Securities class actions

Numerous shareholder class action suits have been filed against us in the United States District Court for the Northern District of Oklahoma. The majority of the suits allege that we and co-defendants, WilTel Communications (WilTel), previously an owned subsidiary known as Williams Communications, and certain corporate officers, have acted jointly and separately to inflate the stock price of both companies. Other suits allege similar causes of action related to a public offering in early January 2002, known as the FELINE PACS offering. These cases were filed against us, certain corporate officers, all members of our Board of Directors and all of the offerings' underwriters. These cases have all been consolidated and an order has been issued requiring separate amended consolidated complaints by our equity holders and WilTel equity holders. The underwriters of this offering have requested indemnification from these cases. If granted, costs incurred as a result of these indemnifications will not be covered by our insurance policies. The amended complaint of the WilTel securities holders was filed on September 27, 2002, and the amended complaint of our securities holders was filed on October 7, 2002. This amendment added numerous claims related to Power. On April 2, 2004, the purported class of our securities holders filed a partial motion for summary judgment with respect to certain disclosures made in connection with our public offerings during the class period.

In addition, four class action complaints have been filed against us, the members of our Board of Directors and members of our Benefits and Investment Committees under the Employee Retirement Income Security Act (ERISA) by participants in our 401(k) plan. A motion to consolidate these suits has been approved. On July 14, 2003, the Court dismissed us and our Board from the ERISA suits, but not the members of the Benefits and Investment Committees to whom we might have an indemnity obligation. If it is determined that we have an indemnity obligation, we expect that any costs incurred will be covered by our insurance policies. The Department of Labor is also independently investigating our employee benefit plans. On May 3, 2004, plaintiffs requested permission to amend their complaint to add additional Investment Committee members and to again name the Board of Directors. That permission was granted June 7, 2004, and a motion to dismiss was filed on behalf of the Board on July 15, 2004. Derivative shareholder suits have been filed in state court in Oklahoma, all based on similar allegations. On August 1, 2002, a motion to consolidate and a motion to stay these Oklahoma suits pending action by the federal court in the shareholder suits were approved.

Oklahoma securities investigation

On April 26, 2002, the Oklahoma Department of Securities issued an order initiating an investigation of us and WilTel regarding issues associated with the spin-off of WilTel and regarding the WilTel bankruptcy. We have no pending inquiries in this investigation, but are committed to cooperate fully in the investigation.

Shell offshore litigation

On November 30, 2001, Shell Offshore, Inc. filed a complaint at the FERC against Williams Gas Processing - Gulf Coast Company, L.P. (WGPGCC), Williams Gulf Coast Gathering Company (WGCGC), Williams Field Services Company (WFS) and Transco, alleging concerted actions by the affiliates frustrating the FERC's regulation of Transco. The alleged actions are related to offers of gathering service by WFS and its subsidiaries on the deregulated North Padre Island offshore gathering system. On September 5, 2002, the FERC issued an order reasserting jurisdiction over that portion of the North Padre Island facilities previously transferred to WFS. The FERC also determined an unbundled gathering rate for service on these facilities which is to be collected by Transco. Transco, WGPGCC, WGCGC and WFS believe their actions were reasonable and lawful and each has filed petitions for review of the FERC's orders with the U.S. Court of Appeals for the District of Columbia. On July 13, 2004, the Court of Appeals reversed the FERC's decision, ruling that FERC's attempt to impose regulated rates was without legal basis.

TAPS Quality Bank

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. Primary issues being litigated include the appropriate valuation of the naphtha, heavy distillate, vacuum gas oil and residual product cuts within the TAPS Quality Bank as well as the appropriate retroactive effects of the determinations. WAPI's interest in these proceedings is material as the matter involves claims by crude producers and the State of Alaska for retroactive payments plus interest of up to $181 million. Due to the sale of WAPI's interests on March 31, 2004, no future Quality Bank liability will accrue but any liability that existed as of the date of the sale will remain a Williams's liability. Because of the complexity of the issues involved, however, the outcome cannot be predicted with certainty nor can the likely result be quantified. Certain periodic discussions have been held and continue among some of the litigants. Because of the number of parties involved and the diversity of positions, no comprehensive terms have been identified that could be considered probable to achieve final settlement among all parties. The FERC and RCA presiding administrative law judges are expected to render their joint and/or individual initial decision(s) sometime during the third quarter of 2004. Although we sold WAPI, we retained potential liability for any retroactive payments that may be awarded in these proceedings for the period ending on March 31, 2004.

Deepwater Construction Litigation

On February 12, 2004, Technip Offshore Contractors, Inc. (TOCI) served WFS, as agent for Williams Fields Services Company - Gulf Coast Company, L.P. and Williams Oil Gathering, L.L.C., with a lawsuit brought in federal court in Houston, Texas. TOCI alleges breach of its contract with us for the construction of export pipelines connected to the Devils Tower SPAR in the Gulf of Mexico. TOCI seeks (1) acceleration of our obligation to pay amounts held as retention and (2) payment of almost $10 million for the value of disputed change orders. We have filed counterclaims seeking almost $7 million arising from damages suffered due to TOCI's breaches of the contract, including liquidated delay damages. The litigation is in the early stages of discovery.

Colorado Royalty Litigation

On June 27, 2002, a royalty owner in the Piceance basin of Colorado filed suit against Williams Production RMT Company alleging that we breached our lease agreements and violated the Colorado Deceptive Trade Practices Act by making various deductions from his royalty payments from 1996 to date. On August 2, 2004, the jury returned its verdict in the amount of $4.1 million for the plaintiff. The verdict included a finding of bad faith which could potentially triple the damage award. The verdict is not yet final pending post-trial motions, but we expect to appeal the verdict if it is not set aside by the court.

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. At June 30, 2004, 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 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 coverage, recovery from customers or other indemnification arrangements, will not have a materially adverse effect upon our future financial position.

COMMITMENTS

Power has entered into certain contracts giving it the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are currently in operation throughout the continental United States. At June 30, 2004, Power's estimated committed payments under these contracts are approximately $210 million for the remainder of 2004, range from approximately $397 million to $423 million annually through 2017 and decline over the remaining five years to $58 million in 2022. Total committed payments under these contracts over the next eighteen years are approximately $6.5 billion.

GUARANTEES

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 exceed the minimum purchase price.

In connection with the construction of a joint venture pipeline project, we guaranteed, through a put agreement, certain portions of the joint venture's project financing in the event of nonpayment by the joint venture. Our potential liability under this guarantee ranges from zero percent to 100 percent of the outstanding project financing, depending on our ability and the other project member's ability to meet certain performance criteria. As of June 30, 2004, the total outstanding project financing is $32.8 million. While our maximum potential liability is the full amount of the financing, based on a recently executed Memorandum of Agreement (MOA), our exposure has been significantly reduced. On March 8, 2004, we entered into the MOA, in which the partner in the joint venture assumed 100 percent of project development costs to date as well as responsibility for any ongoing additional costs, pending a final determination of whether the project will go forward. Based on the MOA and the current status of the project, it is highly unlikely that any obligation would be incurred with respect to the project. The put agreement expires in March 2005. We have not accrued any amounts related to the guarantee at June 30, 2004.

We have guaranteed commercial letters of credit totaling $17 million on behalf of an equity method investee. These expire in January 2005, and have no carrying value.

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 and have a maximum potential exposure of approximately $50 million at June 30, 2004. Our exposure declines systematically throughout the remaining term of WilTel's obligations. The carrying value of these guarantees is approximately $45 million at June 30, 2004 and is recorded as a non-current liability.

We have provided guarantees on behalf of certain partnerships in which we have an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. These guarantees continue until we withdraw from the partnerships. No amounts have been accrued at June 30, 2004.

14. COMPREHENSIVE INCOME (LOSS)

Comprehensive income (loss) from both continuing and discontinued operations is as follows:

	THREE MONTHS ENDED JUNE 30, 2004	THREE MONTHS ENDED JUNE 30, 2003	SIX MONTHS ENDED JUNE 30, 2004	SIX MONTHS ENDED JUNE 30, 2003
	(MILLIONS)		(MILLIONS)	
Net income (loss)	$ (18.2)	$ 269.7	$ (8.3)	$ (544.8)
Other comprehensive income (loss):				
Unrealized gains on securities	--	4.4	--	.2
Net realized losses on securities	--	--	3.0	--
Unrealized losses on derivative instruments	(83.8)	(266.1)	(268.4)	(450.2)
Net reclassification into earnings of derivative instrument losses	51.3	8.5	98.0	23.8
Foreign currency translation adjustments	(6.2)	28.9	(11.5)	53.6
Minimum pension liability adjustment	--	1.6	.7	1.6
Other comprehensive loss before taxes	(38.7)	(222.7)	(178.2)	(371.0)
Income tax benefit on other comprehensive loss	12.3	96.2	63.7	162.4
Other comprehensive loss	(26.4)	(126.5)	(114.5)	(208.6)
Comprehensive income (loss)	$ (44.6)	$ 143.2	$ (122.8)	$ (753.4)

15. SEGMENT DISCLOSURES

Segments and reclassification of operations

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. Other primarily consists of corporate operations and certain continuing operations previously reported within the International and Petroleum Services segments.

Effective June 1, 2004, and due in part to FERC Order 2004, management and decision-making control of certain regulated gas gathering assets was transferred from our Midstream segment to our Gas Pipeline segment. Consequently, the results of operations were similarly reclassified. All prior periods reflect these classifications.

Effective September 21, 2004, and due in large part to FERC Order 2004, management and decision-making control of our equity method investment in the Aux Sable gas processing plant and related business was transferred from our Midstream segment to our Power segment. Consequently, the results of operations were similarly reclassified. All prior periods reflect these classifications.

Segments - performance measurement

We currently evaluate performance based upon segment profit (loss) from operations which, includes revenues from external and internal customers, operating costs and expenses, depreciation, depletion and amortization, equity earnings (losses) and income (loss) from investments including gains/losses on 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.

Power has entered into intercompany interest rate swaps with the corporate parent, the effect of which is included in Power's segment revenues and segment profit (loss) as shown in the reconciliation within the following tables. The results of interest rate swaps with external counterparties are shown as interest rate swap income (loss) in the Consolidated Statement of Operations below operating income.

The majority of energy commodity hedging by certain of our business units is done through intercompany derivatives with Power which, in turn, enters into offsetting derivative contracts with unrelated third parties. Power bears the counterparty performance risks associated with unrelated third parties.

Notes (Continued)

15. SEGMENT DISCLOSURES (CONTINUED)

The following tables reflect the reconciliation of revenues and operating income (loss) as reported in the Consolidated Statement of Operations to segment revenues and segment profit (loss).

	POWER	GAS PIPELINE	EXPLORATION & PRODUCTION	MIDSTREAM GAS & LIQUIDS	OTHER	ELIMINATIONS	TOTAL
			(MILLIONS)				
THREE MONTHS ENDED JUNE 30, 2004							
Segment revenues:							
External	$ 2,118.7	$ 325.9	$ (19.3)	$ 621.3	$ 2.1	$ --	$ 3,048.7
Internal	235.0	5.1	208.3	9.2	4.9	(462.5)	--
Total segment revenues	2,353.7	331.0	189.0	630.5	7.0	(462.5)	3,048.7
Less intercompany interest rate swap income (loss)	20.5	--	--	--	--	(20.5)	--
Total revenues	$ 2,333.2	$ 331.0	$ 189.0	$ 630.5	$ 7.0	$ (442.0)	$ 3,048.7
Segment profit (loss)	$ 43.8	$ 132.8	$ 43.3	$ 99.5	$ (14.3)	$ --	$ 305.1
Less:							
Equity earnings (losses)	(.9)	5.2	3.2	3.5	(.3)	--	10.7
Loss from investments	--	(.7)	--	(.1)	(10.8)	--	(11.6)
Intercompany interest rate swap income (loss)	20.5	--	--	--	--	--	20.5
Segment operating income (loss)	$ 24.2	$ 128.3	$ 40.1	$ 96.1	$ (3.2)	$ --	285.5
General corporate expenses							(28.3)
Consolidated operating income							$ 257.2
THREE MONTHS ENDED JUNE 30, 2003							
Segment revenues:							
External	$ 2,797.8	$ 320.5	$ (5.8)	$ 488.2	$ 11.6	$ --	$ 3,612.3
Internal	125.7	10.2	206.0	14.0	8.5	(364.4)	--
Total segment revenues	2,923.5	330.7	200.2	502.2	20.1	(364.4)	3,612.3
Less intercompany interest rate swap loss	(16.7)	--	--	--	--	16.7	--
Total revenues	$ 2,940.2	$ 330.7	$ 200.2	$ 502.2	$ 20.1	$ (381.1)	$ 3,612.3
Segment profit (loss)	$ 335.9	$ 115.5	$ 178.7	$ 57.2	$ (51.7)	$ --	$ 635.6
Less:							
Equity earnings (losses)	(3.6)	2.0	2.5	.8	(.7)	--	1.0
Income (loss) from investments	(8.5)	.1	--	4.8	(42.5)	--	(46.1)
Intercompany interest rate swap loss	(16.7)	--	--	--	--	--	(16.7)
Segment operating income (loss)	$ 364.7	$ 113.4	$ 176.2	$ 51.6	$ (8.5)	$ --	697.4
General corporate expenses							(21.8)
Consolidated operating income							$ 675.6

	POWER	GAS PIPELINE	EXPLORATION & PRODUCTION	MIDSTREAM GAS & LIQUIDS	OTHER	ELIMINATIONS	TOTAL
			(MILLIONS)				
SIX MONTHS ENDED JUNE 30, 2004							
Segment revenues:							
External	$ 4,222.6	$ 681.2	$ (34.1)	$ 1,239.6	$ 4.9	$ --	$ 6,114.2
Internal	405.9	8.8	388.3	18.2	14.7	(835.9)	--
Total segment revenues	4,628.5	690.0	354.2	1,257.8	19.6	(835.9)	6,114.2
Less intercompany interest rate swap loss	(1.1)	--	--	--	--	1.1	--
Total revenues	$ 4,629.6	$ 690.0	$ 354.2	$ 1,257.8	$ 19.6	$ (837.0)	$ 6,114.2
Segment profit (loss)	$ 11.8	$ 280.2	$ 94.8	$ 207.1	$ (23.0)	$ --	$ 570.9
Less:							
Equity earnings (losses)	(.2)	9.0	6.1	7.7	(.3)	--	22.3
Loss from investments	--	(1.0)	--	(.3)	(17.3)	--	(18.6)

Intercompany interest rate swap loss	(1.1)	--	--	--	--	--	(1.1)
Segment operating income (loss)	$ 13.1	$ 272.2	$ 88.7	$ 199.7	$ (5.4)	$ --	568.3
General corporate expenses							(60.3)
Consolidated operating income							$ 508.0
SIX MONTHS ENDED JUNE 30, 2003							
Segment revenues:							
External	$ 6,385.8	$ 653.3	$ (12.9)	$ 1,336.1	$ 26.1	$ --	$ 8,388.4
Internal	313.3	17.0	457.0	31.5	22.0	(840.8)	--
Total segment revenues	6,699.1	670.3	444.1	1,367.6	48.1	(840.8)	8,388.4
Less intercompany interest rate swap loss	(22.6)	--	--	--	--	22.6	--
Total revenues	$ 6,721.7	$ 670.3	$ 444.1	$ 1,367.6	$ 48.1	$ (863.4)	$ 8,388.4
Segment profit (loss)	$ 198.9	$ 265.8	$ 292.5	$ 170.0	$ (46.9)	$ --	$ 880.3
Less:							
Equity earnings (losses)	(4.2)	3.8	4.6	(1.8)	3.0	--	5.4
Income (loss) from investments	(8.5)	.1	--	4.8	(42.5)	--	(46.1)
Intercompany interest rate swap loss	(22.6)	--	--	--	--	--	(22.6)
Segment operating income (loss)	$ 234.2	$ 261.9	$ 287.9	$ 167.0	$ (7.4)	$ --	943.6
General corporate expenses							(44.7)
Consolidated operating income							$ 898.9

15. SEGMENT DISCLOSURES (CONTINUED)

	TOTAL ASSETS	
	JUNE 30, 2004	DECEMBER 31, 2003*
	(MILLIONS)	
Power	$ 9,984.9	$ 8,732.9
Gas Pipeline	7,361.9	7,314.3
Exploration & Production	5,316.0	5,347.4
Midstream Gas & Liquids	4,020.2	3,990.3
Other	4,159.9	6,928.7
Eliminations	(5,109.3)	(6,078.2)
	25,733.6	26,235.4
Discontinued operations	434.8	786.4
Total	$ 26,168.4	$ 27,021.8

* Certain amounts have been reclassified as described in Note 2.

16. RECENT ACCOUNTING STANDARDS

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, the SEC staff, in a letter to the EITF Chairman, questioned whether leased mineral rights should be presented as intangible assets rather than property, plant and equipment. In March 2004, the EITF reached a consensus that all mineral rights should be considered tangible assets for accounting purposes. Therefore, no reclassification will be required.

In May 2004, the FASB issued FSP No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." This guidance is effective for us beginning in third quarter 2004 and supersedes FSP No. FAS 106-1. We are evaluating the impact of the Act on future obligations of the plan. If the plan is determined to be actuarially equivalent and thus eligible for the subsidy, the change in the obligation attributable to prior service will be deferred and recognized over future periods beginning in third-quarter 2004 (see Note 8).

EITF Issue No. 03-1, "The Meaning of Other Than Temporary Impairment and Its Application to Certain Investments," contains recognition and measurement guidance that must be applied to investment impairment evaluations in interim reporting periods beginning after June 15, 2004. This Issue is required to be adopted on a prospective basis. Specifically, the Issue provides guidance to determine whether an investment is impaired and whether that impairment is other than temporary. The Issue applies to debt and equity securities, except equity securities accounted for under the equity method. We are reviewing this Issue and have yet to determine the impact to our Consolidated Balance Sheet and Consolidated Statement of Operations.

17. SUBSEQUENT EVENTS

NOTES PAYABLE AND LONG-TERM DEBT

In August 2004, we made cash tender offers and consent solicitations for all of our 8.625 percent senior notes due 2010. Approximately $792.8 million, or approximately 99 percent, aggregate principal amount of notes were accepted for purchase. In conjunction with this purchase, we paid premiums of approximately $135 million.

On September 17, 2004, we initiated an offer to exchange up to 43.9 million FELINE PACS units for one share of our common stock plus $1.47 in cash for each unit. The offer expired October 18, 2004 and resulted in approximately 33.1 million of the 44 million issued and outstanding units being tendered and accepted for exchange. The exchange offer reduced our overall debt by approximately $827 million and increased our common stock outstanding by 33.1 million shares. The effect of the exchange, including a pre-tax charge for related expenses of approximately $25 million, will be reflected in the fourth quarter.

OTHER LEGAL MATTERS

As discussed in Note 13, 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. Primary issues being litigated include the appropriate valuation of the naptha, heavy distillate, vacuum gas oil and residual product cuts within the TAPS Quality Bank as well as the appropriate retroactive effects of the determinations.

The FERC and RCA presiding administrative law judges rendered their joint and individual initial decisions during the third quarter of 2004. The initial decisions set forth methodologies for determining the valuations of the product cuts under review and also approved the retroactive application of the approved methodologies for the heavy distillate and residual product cuts. Based on our computation and assessment of ultimate ruling terms that would be considered probable, we recorded an accrual of approximately $134 million in the third quarter of 2004. Because the application of certain aspects of the initial decisions are subject to interpretation, we have calculated the reasonably possible impact of the decisions, if fully adopted by the FERC and RCA, to result in additional exposure to us of approximately $32 million more than we have accrued at September 30, 2004. We will be filing a brief on exceptions to the initial decisions to both the FERC and RCA on November 16, 2004, and reply briefs are due on February 1, 2005. Decisions from the Commissions will then be issued likely before the end of 2005. It is unlikely that we will be required to make any payments with respect to this matter until sometime after the Commission decisions.

As discussed in Note 6, in July 2004, an arbitration panel awarded Gulf Liquids approximately $83.3 million related to obligations under construction contracts. On November 1, 2004, Winterthur remitted approximately $85 million to us in the settlement of certain disputes regarding obligations under construction contracts. As a result of the payment, we will recognize pre-tax income of approximately $95 to $100 million within Income from discontinued operations in the fourth quarter.

ITEM 2

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

RECENT EVENTS AND COMPANY OUTLOOK

In February 2003, we outlined our planned business strategy in response to the events that significantly impacted the energy sector and our company during late 2001 and much of 2002, including the collapse of Enron and the severe decline of the telecommunications industry. The plan focused on migrating to an integrated natural gas business comprised of a strong, but smaller, portfolio of natural gas businesses; reducing debt; and increasing our liquidity through asset sales, strategic levels of financing and reductions in operating costs. The plan was designed to address near-term and medium-term debt and liquidity issues, to de-leverage the company with the objective of returning to investment grade status and to develop a balance sheet and cash flows capable of supporting and ultimately growing our remaining businesses.

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, we successfully executed certain critical components of our plan during 2003. Key execution steps for 2004 and beyond included the completion of planned asset sales; additional reductions of our SG&A costs; the replacement of our cash-collateralized letter of credit and revolver facility with facilities that do not encumber cash; and continuation of our efforts to exit from the Power business.

Asset sales during 2004 were initially expected to generate proceeds of approximately $800 million. In first-quarter 2004, we completed the sale of our Alaska refinery and related assets for approximately $304 million. On July 28, 2004 we completed the sale of three straddle plants in western Canada for approximately $536 million. In addition to these transactions, we currently expect to generate additional proceeds from the sale of assets of approximately $50 to $100 million.

In April 2004, we entered into two new unsecured credit facilities totaling $500 million, primarily for issuing letters of credit. During April 2004, use of these facilities released approximately $500 million of restricted cash, restricted investments and margin deposits. Also, on May 3, 2004, we entered into a new three-year, $1 billion secured revolving credit facility. The revolving facility is secured by certain Midstream assets and a guarantee from WGP (see Note 12 of Notes to Consolidated Financial statements).

As part of our planned strategy, on February 25, 2004, our Exploration & Production segment amended its $500 million secured note facility, which was originally due May 30, 2007. The amendment provided more favorable terms including a lower interest rate and an extension of the maturity by one year (see Note 12 of Notes to Consolidated Financial Statements).

On March 15, 2004, we retired $679 million of senior unsecured 9.25 percent notes due March 15, 2004. The amount represented the outstanding balance subsequent to the fourth-quarter 2003 tender which retired $721 million of the original $1.4 billion balance.

In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of a specified series of our outstanding notes and debentures. As of the June 8, 2004 tender offer expiration date, we accepted for purchase $1.17 billion of the notes for purchase. In May 2004, we also repurchased debt of approximately $255 million of various maturities on the open market (see Note 12 in Notes to Consolidated Financial Statements). Our repurchase of these notes served to decrease debt and will result in reduced annual interest expense and reduced administrative costs associated with the various debt issues.

Long-term debt, excluding the current portion, at June 30, 2004 was approximately $9.5 billion.

We are seriously considering the possibility of creating a public master limited partnership (MLP) that would own and operate certain Midstream assets. Initial operations would include various NGL storage, fractionation and transportation assets most of which we had previously considered selling due to the strong interest from existing MLP's in this sector.

POWER BUSINESS STATUS

Since mid-2002, we have been pursuing a strategy of exiting the Power business and have worked with financial advisors to assist with this effort. To date, several factors have contributed to the difficulty of achieving a complete exit from this business, including the following with respect to the wholesale power industry:

- oversupply position in most markets expected through the balance of the decade,

- slow North American gas supply response to high gas prices, and

- expectations of hybrid regulated/deregulated market structure for several years.

As a result of these factors and the size of our Power business, the number of financially viable parties expressing an interest in purchasing the entire business has been limited. Additionally, the current and near term view of the wholesale power market, which we interpret as depressed, has strongly influenced these parties' view of value and related risk associated with this business.

Because market conditions may change, and we cannot determine the impact of this on a buyer's point of view, amounts ultimately received in any portfolio sale, contract liquidation or realization may be significantly different from the estimated economic value or carrying values reflected in the Consolidated Balance Sheet. In addition, our tolling agreements are not derivatives and thus have no carrying value in the Consolidated Balance Sheet pursuant to the application of EITF 02-3. Based on current market conditions, certain of these agreements are forecasted to realize significant future losses. It is possible that we may sell contracts for less than their carrying value or enter into agreements to terminate certain obligations, either of which could result in significant future loss recognition or reductions of future cash flows.

We continue to evaluate alternatives and discuss our plans and operating strategy for the Power business with our Board of Directors. As an alternative to continuing a plan of pursuing a complete exit from the Power business, we are evaluating whether the benefits of realizing the positive cash flows expected to be generated by this business through continued ownership exceed the benefits of a sale at a depressed price. If we pursue this alternative, we expect to continue our current program of managing this business to minimize financial risk, generate cash and manage existing contractual commitments.

GENERAL

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 consolidated financial statements and notes in Item 1 [Exhibit 99.5] reflect the results of operations, financial position and cash flows through the date of sale, as applicable, of the following components as discontinued operations (see Note 6 of Notes to Consolidated Financial Statements).

During second-quarter 2004, our Board of Directors approved a plan authorizing management to negotiate and facilitate a sale of the straddle plants in western Canada, which were part of the Midstream segments. As a result, these assets and their related income and cash flows are now reported as discontinued operations. In addition, the following components are included as discontinued operations:

- retail travel centers concentrated in the Midsouth, part of the previously reported Petroleum Services segment;

- refining and marketing operations in the Midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;

- Texas Gas Transmission Corporation, previously one of Gas Pipeline's segments;

- natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment;

- bio-energy operations, part of the previously reported Petroleum Services segment;

- our general partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;

- the Colorado soda ash mining operations, part of the previously reported International segment;

- certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream segment;

- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment;

- Gulf Liquids New River Project LLC, previously part of the Midstream segment.

Effective June 1, 2004, and due in part to FERC Order 2004, management and decision-making control of certain regulated gas gathering assets was transferred from our Midstream segment to our Gas Pipeline segment. Consequently, the results of operations were similarly reclassified. All prior periods reflect these classifications.

Unless indicated otherwise, the following discussion and analysis of results of operations, financial condition and liquidity relates to our current continuing operations and should be read in conjunction with the consolidated financial statements and notes thereto included in Item 1 [Exhibit 99.5] of this document and our 2003 Annual Report on Form 10-K, as restated and amended.

RESULTS OF OPERATIONS

CONSOLIDATED OVERVIEW

The following table and discussion is a summary of our consolidated results of operations for the three and six months ended June 30, 2004. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	THREE MONTHS ENDED JUNE 30,			SIX MONTHS ENDED JUNE 30,		
	2004	2003	% CHANGE FROM 2003(1)	2004	2003	% CHANGE FROM 2003 (1)
	(MILLIONS)			(MILLIONS)		
Revenues	$3,048.7	$3,612.3	-16%	$6,114.2	$8,388.4	-27%
Costs and expenses:						
Costs and operating expenses	2,658.3	3,024.8	+12%	5,348.2	7,448.4	+28%
Selling, general and administrative expenses	81.9	115.4	+29%	166.3	221.0	+25%
Other (income) expense - net	23.0	(225.3)	NM	31.4	(224.6)	NM
General corporate expenses	28.3	21.8	-30%	60.3	44.7	-35%
Total costs and expenses	2,791.5	2,936.7	+5%	5,606.2	7,489.5	+25%
Operating income	257.2	675.6	-62%	508.0	898.9	-43%
Interest accrued - net	(221.6)	(394.6)	+44%	(460.9)	(735.5)	+37%
Interest rate swap income (loss)	6.8	(6.1)	NM	(1.3)	(8.9)	+85%
Investing income (loss)	11.7	(43.2)	NM	22.0	3.1	NM
Early debt retirement costs	(96.8)	--	NM	(97.3)	--	NM
Minority interest in income of consolidated subsidiaries	(6.0)	(6.0)	--	(10.8)	(9.5)	-14%
Other income (expense) - net	13.4	13.9	-4%	14.8	36.0	-59%
Income (loss) from continuing operations before income taxes and cumulative effect of change in accounting principles	(35.3)	239.6	NM	(25.5)	184.1	NM
Provision (benefit) for income taxes	(17.3)	125.9	NM	(6.0)	113.5	NM
Income (loss) from continuing operations	(18.0)	113.7	NM	(19.5)	70.6	NM
Income (loss) from discontinued operations	(.2)	156.0	NM	11.2	145.9	-92%
Income (loss) before cumulative effect of change in accounting principles	(18.2)	269.7	NM	(8.3)	216.5	NM
Cumulative effect of change in accounting principles	--	--	--	--	(761.3)	+100%
Net income (loss)	(18.2)	269.7	NM	(8.3)	(544.8)	+98%
Preferred stock dividends	--	22.7	+100%	--	29.5	+100%
Income (loss) applicable to common stock	$ (18.2)	$ 247.0	NM	$ (8.3)	$ (574.3)	+99%

(1) + = Favorable Change; - = Unfavorable Change; 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 June 30, 2004 vs. Three Months Ended June 30, 2003

Our revenues decreased $563.6 million due primarily to decreased revenues at our Power segment, slightly offset by increased revenues at our Midstream segment. Power revenues decreased approximately $569.8 million due primarily to lower power sales volumes and decreased net unrealized gains on power and natural gas derivative contracts due primarily to the impact of a lesser increase in forward natural gas prices in second-quarter 2004. Partially offsetting these decreases were increased crude and refined product revenues resulting from increased sales to optimize pipeline and storage capacity as well as increased realized interest rate revenues due to higher interest rates in 2004. Midstream's revenues increased $128.3 million due primarily to higher product sales for natural gas liquids (NGLs) and olefins resulting from increased production volumes and higher market prices, and increased fee revenue from deepwater assets. The increases at Midstream were partially offset by the sale of our wholesale propane business in fourth-quarter 2003.

Costs and operating expenses decreased $366.5 million due primarily to decreased costs and operating expenses at Power, slightly offset by increased costs at Midstream. The decrease at Power is due primarily to lower power purchase volumes, partially offset by increased crude and refined product costs. The increase at Midstream is due primarily to higher natural gas and ethane purchases required to produce NGL and olefins. The increases were offset by lower natural gas liquids trading purchases due to the 2003 sale of our wholesale propane business.

Selling, general and administrative expenses decreased $33.5 million. This cost reduction is due primarily to reduced staffing levels at Power reflective of our strategy to exit this business.

Other (income) expense - net in 2004 includes an $11.3 million loss provision related to an ownership dispute on prior period production included in the Exploration & Production segment and a $9 million write-off of previously-capitalized costs on an idled segment of Northwest's system. Other (income) expense - net in 2003 includes a $175 million gain from the sale of a Power contract and $91.5 million in net gains from the sale of Exploration & Production's interests in natural gas properties. Partially offsetting these gains in 2003 was a $25.5 million charge at Northwest to write off capitalized software development costs and a $20 million charge related to a settlement by Power with the CFTC (see Note 13 of Notes to Consolidated Financial Statements).

General corporate expenses increased $6.5 million due primarily to increased third-party costs associated with compliance activities and with efforts to evaluate and implement certain cost reduction strategies through internal initiatives and outsourcing of certain services.

Interest accrued - net decreased $173 million due primarily to:

- $117 million lower interest expense and fees at Exploration & Production, due primarily to the May 2003 prepayment of the RMT note payable;

- $24 million lower amortization expense related to deferred debt issuance costs, due primarily to the reduction of debt; and

- a $24 million decrease reflecting lower average borrowing levels.

We entered into interest rate swaps with external counterparties primarily in support of the energy-trading portfolio (see Note 15 of Notes to Consolidated Financial Statements). The change in fair market value of these swaps was $12.9 million more favorable in 2004 than 2003. The total notional amount of these swaps was approximately $300 million at June 30, 2004 and June 30, 2003.

Investing income (loss) increased $54.9 million due primarily to the absence in 2004 of the following 2003 charges, partially offset by a $10.8 million impairment of our investment in equity securities of Longhorn Partners Pipeline LP (Longhorn):

- a $42.4 million 2003 impairment of our investment in equity and debt securities of Longhorn;

- a $13.5 million impairment of a cost-based investment in a company holding phosphate reserves; and

- an $8.5 million impairment of our investment in Aux Sable.

Early debt retirement costs for 2004 includes premiums, fees and expenses related to the debt repurchase and the debt tender offer and consent solicitations that we completed in the second quarter.

Other income (expense) - net, below operating income in 2004, includes a $4.1 million net gain in 2004 and a $7.9 million net gain in 2003 related to a foreign currency transaction gain or loss on a Canadian dollar denominated note receivable and an offsetting derivative gain or loss on a forward contract to fix the U.S. dollar principal cash flows from the note receivable. The note receivable was repaid in July 2004 with proceeds from the sale of the Canadian straddle plants and the related forward contract was terminated.

The provision (benefit) for income taxes was favorable by $143.2 million due primarily to a pre-tax loss in 2004 as compared to a pre-tax income for 2003. The effective income tax rate for 2004 is greater than the federal statutory rate due primarily to the effect of state income taxes, partially offset by net foreign operations and an accrual for income tax contingencies. The effective income tax rate for 2003 is greater than the federal statutory rate due primarily to the financial impairment of certain investments, capital losses generated, for which valuation allowances were established, nondeductible expenses and an accrual for income tax contingencies.

Income (loss) from discontinued operations decreased $156.2 million from an income position in 2003 of $156 million to a loss position in 2004 of $.2 million (see Note 6 of Notes to Consolidated Financial Statements). The decrease in the operating results from discontinued operations activities from an income position in 2003 to a loss position in 2004 is reflective of income (loss) from discontinued operations for the following operations:

- the absence of $9.3 million income from discontinued operations at Texas Gas;

- the absence of $8.3 million income from discontinued operations at Williams Energy Partners as well as a $5.1 million loss from discontinued operations in 2004 which includes the settlement related to the environmental indemnifications;

- the absence of $7.9 million income from discontinued operations from Raton Basin and Hugoton Embayment natural gas exploration and production properties; and

- a $9.6 million decrease in loss from discontinued operations for Gulf Liquids New River Project LLC (Gulf Liquids).

The 2003 gain on sale of discontinued operations of $232.9 million includes:

- a $11.1 million impairment of the soda ash mining facility located in Colorado;

- a $24.7 million gain on the sale of an earn-out agreement that we retained following the first quarter 2003 sale of a refinery located in Memphis, Tennessee;

- a $39.9 million gain on sale of natural gas exploration and production properties;

- a $275.6 million gain on the sale of our 100 percent general partnership interest and 54.6 percent limited partner investment in Williams Energy Partners; and

- a $92.6 million impairment of Gulf Liquids New River Project LLC.

In June 2003, we redeemed all of our outstanding 9.875 percent cumulative-convertible preferred shares. Thus, no preferred dividends were paid in 2004.

Six Months Ended June 30, 2004 vs. Six Months Ended June 30, 2003

Our revenues decreased approximately $2.3 billion due primarily to decreased revenues at our Power, Midstream and Exploration & Production segments. Power revenues decreased approximately $2.1 billion due primarily to lower power and crude and refined products sales volumes and decreased net unrealized gains on natural gas derivative contracts due primarily to the impact of forward natural gas prices. Midstream's revenues decreased $109.8 million due primarily to the sale of our wholesale propane business in the fourth quarter of 2003. Largely offsetting this decrease at Midstream were higher product sales for NGLs and olefins resulting from higher production volumes and higher market prices. In addition, Exploration & Production's revenues decreased $89.9 million due primarily to lower domestic production revenues from lower net realized average prices and lower production volumes as a result of 2003 property sales, lower gas management revenues, lower income from the utilization of excess transportation capacity and lower income on derivative instruments that did not qualify for hedge accounting.

Costs and operating expenses decreased $2.1 billion due primarily to decreased costs and operating expenses at Power and Midstream. The decrease at Power is due primarily to lower power purchase volumes and lower crude and refined products costs. In addition, costs at Midstream were impacted by the sale of our wholesale propane business offset by higher NGL and olefins production costs.

Selling, general and administrative expenses decreased $54.7 million, due primarily to reduced staffing levels at Power reflective of our strategy to exit this business. Also contributing to the decrease at Power was the absence of $12.6 million of expense related to the accelerated recognition of deferred compensation during 2003.

Other (income) expense - net, within operating income, in 2004 includes an $11.3 million loss provision related to an ownership dispute on prior period production included in the Exploration & Production segment; a $9 million write-off of previously-capitalized costs on an idled segment of Northwest's system; and $6.1 million in fees related to the sale of certain receivables to a third party. Other expense - net in 2003 includes a $175 million gain from the sale of a Power contract and $91.5 million in net gains from the sale of Exploration & Production's interests in certain natural gas properties. Partially offsetting these gains in 2003 was a $25.5 million charge at Northwest to write-off capitalized software development costs for a service delivery system and a $20 million charge related to a settlement by Power with the CFTC (see Note 13 of Notes to Consolidated Financial Statements).

General corporate expenses increased $15.6 million due primarily to increased third-party costs associated with compliance activities and with efforts to evaluate and implement certain cost reduction strategies through internal initiatives and outsourcing of certain services.

Interest accrued - net decreased $274.6 million due primarily to:

- $203 million lower interest expense and fees at Exploration & Production due primarily to the May 2003 prepayment of the RMT note payable;

- $34 million lower amortization expense related to deferred debt issuance costs, primarily due to the reduction of debt;

- a $28 million decrease reflecting lower average borrowing levels;

- a $10 million decrease reflecting lower average interest rates on long-term debt;

- the absence in 2004 of $12 million of interest expense within Power related to a FERC ruling in 2003; and

- an $18.5 million decrease in capitalized interest, which offsets interest accrued, due primarily to completion of certain Midstream projects in the Gulf Coast Region.

We entered into interest rate swaps with external counterparties primarily in support of the energy-trading portfolio (see Note 15 of Notes to Consolidated Financial Statements). The change in fair market value of these swaps was $7.6 million more favorable in 2004 than 2003. The total notional amount of these swaps was approximately $300 million at June 30, 2004 and June 30, 2003.

Investing income increased $18.9 million due primarily to:

- the absence in 2004 of a $42.4 million impairment of our investment in equity and debt securities of Longhorn in 2003, partially offset by $6.5 million net unreimbursed Longhorn recapitalization advisory fees in 2004;

- the absence in 2004 of a $12 million impairment of our cost-based investments in Algar Telecom S.A. and a $13.5 million impairment of a cost-based investment in a company holding phosphate reserves;

- $13.9 million higher equity earnings from Discovery due primarily to the absence of unfavorable accounting adjustments recorded at the partnership in 2003;

- the absence in 2004 of a $8.5 million impairment of our - investment in Aux Sable;

- $41 million lower interest income at Power due primarily to a favorable adjustment in 2003 resulting from certain 2003 FERC proceedings;

- $10 million lower interest income on advances to Longhorn that were subsequently exchanged for preferred stock; and

- a $10.8 million impairment of our investment in equity securities of Longhorn in 2004.

Early debt retirement costs for 2004 include premiums, fees and expenses related to the May 2004 debt repurchase and the debt tender offer and consent solicitations that we completed in the second quarter.

Other income (expense) - net, below operating income includes a $6.7 million net gain in 2004 and a $20.4 million net gain in 2003 related to a foreign currency transaction gain or loss on a Canadian dollar denominated note receivable and an offsetting derivative gain or loss on a forward contract to fix the U.S. dollar principal cash flows from the note receivable. The note receivable was repaid in July 2004 with proceeds from the sale of the Canadian straddle plants and the related forward contract was terminated.

The provision (benefit) for income taxes was favorable by $119.5 million due primarily to a pre-tax loss in 2004 as compared to a pre-tax income for 2003. The effective income tax rate for 2004 is less than the federal statutory rate due primarily to net foreign operations and an accrual for income tax contingencies, partially offset by the effect of state income taxes. The effective income tax rate for 2003 is greater than the federal statutory rate due primarily to the financial impairment of certain investments, capital losses generated, for which valuation allowances were established, nondeductible expenses and an accrual for income tax contingencies.

Income (loss) from discontinued operations decreased $134.7 million (see Note 6 of Notes to Consolidated Financial Statements). The decrease in the operating results from discontinued operations activities is reflective of income (loss) from discontinued operations for the following operations:

- the absence of $58.5 million income from discontinued operations at Texas Gas;

- the absence of $28.5 million income from discontinued operations at Alaska refining, retail and pipeline;

- the absence of $22.1 million of income from discontinued operations at Williams Energy Partners which was sold in 2003;

- a $5.6 million loss from discontinued operations at Williams Energy Partners which includes the settlement related to the environmental indemnifications;

- the absence of $20.1 million income from discontinued operations from Raton Basin and Hugoton Embayment natural gas exploration and production properties;

- a $26.8 million decrease in loss from discontinued operations for Gulf Liquids; and

- an $8.8 million increase in income from discontinued operations for Canadian straddle plants.

The 2003 gain on sale of discontinued operations of $115.6 million includes:

- a $109 million impairment of Texas Gas Transmission;

- an $8 million impairment of the Alaska refinery, retail and pipeline assets;

- a $16.1 million impairment of the soda ash mining facility located in Colorado;

- a $29.4 million gain on the sale of a refinery and other related operations located in Memphis, Tennessee, of which $24.7 million relates to the sale of an earn-out agreement that we retained following the sale of the assets;

- a $39.9 million gain on sale of certain natural gas exploration & production properties;
- a $6.4 million loss on sale of our Bio-energy operations;
- a $275.6 million gain on the sale of Williams Energy Partners; and
- a $92.6 million impairment of Gulf Liquids.

The cumulative effect of change in accounting principles reduced net income for 2003 by $761.3 million due to a $762.5 million charge related to the adoption of EITF 02-3, slightly offset by $1.2 million related to the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" (see Note 3 of Notes to Consolidated Financial Statements).

In June 2003, we redeemed all of our outstanding 9.875 percent cumulative-convertible preferred shares. Thus, no preferred dividends were paid in 2004.

RESULTS OF OPERATIONS - SEGMENTS

We are currently organized into the following segments: Power, Gas Pipeline, Exploration & Production, Midstream and Other. Other primarily consists of corporate operations and certain continuing operations previously reported within the International and Petroleum Services segments. Our management currently evaluates performance based on segment profit (loss) from operations (see Note 15 of Notes to Consolidated Financial Statements).

Prior period amounts have been restated to reflect these segment changes. The following discussions relate to the results of operations of our segments.

POWER

OVERVIEW OF SIX MONTHS ENDED JUNE 30, 2004

As described below, the continued effort to exit from the Power business, combined with liquidity constraints, and the effect of price changes on derivative contracts significantly influenced Power's operating results for the first half of 2004.

In the first half of 2004, Power continued to focus on 1) terminating or selling all or portions of the portfolio, 2) maximizing cash flow, 3) reducing risk, and 4) managing existing contractual commitments. These efforts are consistent with our 2002 decision to sell all or portions of Power's portfolios. The decrease in revenues, costs and selling, general and administrative expenses reflect our efforts to exit the Power business.

Key factors that influence Power's financial condition and operating performance include the following:

- prices of power and natural gas, including changes in the margin between power and natural gas prices;
- changes in market liquidity, including changes in the ability to economically hedge the portfolio;
- changes in power and natural gas price volatility;
- changes in interest rates;
- changes in the regulatory environment; and
- changes in power and natural gas supply and demand.

OUTLOOK FOR THE REMAINDER OF 2004

In the remainder of 2004, we anticipate further variability in Power's earnings due in part to the difference in accounting treatment of derivative contracts at fair value and the underlying non-derivative contracts on an accrual basis. This difference in accounting treatment combined with the volatile nature of energy commodity markets could result in future operating gains or losses. Some of Power's tolling contracts have a negative fair value, which is not reflected in the financial statements since these contracts are not derivatives. The negative fair value of these tolling contracts may result in future accrual losses. Continued efforts to sell all or a portion of these contracts may also have a significant impact on future earnings as proceeds may differ significantly from carrying values. The inability of counterparties to perform under contractual obligations due to their own credit constraints could also affect future operations.

PERIOD-OVER-PERIOD RESULTS

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
Segment revenues	$ 2,353.7	$ 2,923.5	$ 4,628.5	$ 6,699.1
Segment profit	$ 43.8	$ 335.9	$ 11.8	$ 198.9

Three months ended June 30, 2004 vs. three months ended June 30, 2003

The $569.8 million decrease in revenues includes a $407.4 million decrease in realized revenues and a $162.4 million decrease in net unrealized gains.

Realized revenues represent 1) revenue from sale of commodities or completion of energy-related services and 2) gains and losses from the net financial settlement of derivative contracts. The $407.4 million decrease in realized revenues is primarily due to a decrease in power and natural gas realized revenues of $536.3 million, partially offset by a $58.9 million increase in crude and refined products realized revenues and a $70 million increase in interest rate portfolio realized revenues.

Power and natural gas revenues decreased primarily due to a 42 percent decrease in power sales volumes. Sales volumes decreased because Power did not replace certain long-term physical contracts that expired or were terminated in 2003, primarily due to a lack of market liquidity and efforts to reduce our commitment to the Power business. Also, during the second quarter of 2003, Power corrected the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001, resulting in the recognition of $93 million in revenue that was attributable to prior periods. Refer to Note 1 of Notes to Consolidated Financial Statements for further information. The general decrease in power and natural gas realized revenues is partially offset by increased intercompany revenue from Midstream. Sales to Midstream have increased from the prior period as a result of higher processing margins, reflecting increased demand for natural gas used at its gas processing plants.

Crude and refined products realized revenues increased primarily as a result of increased refined products sales made in order to optimize pipeline and storage capacity that Power expects to sell in 2004.

The increase in realized revenues from Power's interest rate portfolio reflects the impact of a second-quarter 2004 rise in interest rates in contrast to a second quarter 2003 decline in rates.

Unrealized gains and losses represent changes in the fair value of derivative contracts with a future settlement or delivery date. The $162.4 million decrease in net unrealized gains is primarily due to a $183.8 million decrease in net unrealized gains on power and natural gas derivative contracts, partially offset by an $18.9 million increase in unrealized gains on interest rate derivatives.

The decrease in power and natural gas net unrealized gains is largely due to a lesser increase in forward natural gas prices in second-quarter 2004 compared to the same period in 2003. Interest rate unrealized gains (losses) increased due to an increase in forward interest rates in 2004 compared to a decrease in forward interest rates in 2003.

Power's costs represent purchases of commodities and fees paid for energy related services. Costs decreased $413.9 million primarily due to a $457.4 million decrease in power and natural gas costs offset by a $43.5 million increase in crude and refined products costs. Power and natural gas costs decreased largely due to a 44 percent decrease in power purchase volumes due largely to the expiration or termination of certain long-term physical contracts in 2003. This decrease was partially offset by the effect of an approximate 17 percent increase in the average price for natural gas purchases. Second-quarter 2004 reductions to liabilities associated with power marketing activities in California during 2000 and 2001 primarily resulting from recent contract agreements resulted in gains of $10.4 million, which contributed to the decrease in costs discussed above. Crude and refined products costs increased due to increased refined products purchases made in order to optimize pipeline and storage capacity that Power expects to sell in 2004.

Selling, general and administrative expenses decreased $24 million. Compensation expense declined in 2004 as a result of staff reductions in prior years combined with the accelerated recognition in 2003 of certain deferred compensation arrangements. Power employed approximately 235 employees at June 30, 2004 compared to 265 employees at June 30, 2003. Additionally, a $6.5 million increase in bad debt reserves associated with a contract termination settlement in 2003 also contributed to the decrease.

Other (income) expense - net in 2003 includes a $175 million gain from the sale of an energy-trading contract partially offset by a $20 million charge for a settlement with the CFTC in 2003.

Six months ended June 30, 2004 vs. six months ended June 30, 2003

The $2.1 billion decrease in revenues includes a $2.0 billion decrease in realized revenues and a $98.4 million decrease in unrealized gains (losses).

The $2 billion decrease in realized revenues is primarily due to a $1.5 billion decrease in power and natural gas realized revenues and a $524 million decrease in crude and refined products realized revenues, partially offset by a $55.5 million increase in interest rate portfolio realized revenues.

Power and natural gas realized revenues decreased primarily due to a 45 percent decrease in power sales volumes. Also, during the second quarter of 2003, Power corrected the accounting treatment previously given to certain third party derivative contracts during 2002 and 2001, resulting in the recognition of approximately $107 million in revenues in the second quarter of 2003 attributable to prior periods. Refer to Note 1 of Notes to Consolidated Financial Statements for further information. Power and natural gas revenues in 2003 include a $37 million loss for increased power rate refunds owed to the state of California as the result of FERC rulings, which partially offsets the general decrease discussed above.

Crude and refined products revenues decreased primarily due to the sale of the crude gathering business in 2003 and the continued efforts to exit this line of business.

The increase in realized revenues from Power's interest rate portfolio reflects the impact of a rise in interest rates during the first six months of 2004 in contrast to a decline in rates over the same period during 2003.

Unrealized revenues decreased primarily as a result of a decrease in natural gas unrealized revenues of $106.7 million, largely due to changes in the forward prices of natural gas. Because Power holds fixed price forward purchase contracts for natural gas, an increase in the forward natural gas price results in unrealized gains. However, the increase in the forward price of natural gas for the first six months of 2004 was not as significant as the increase in the same period in 2003. Thus, total unrealized gains related to natural gas derivatives decreased. Offsetting the decrease was the absence of unrealized losses of approximately $70 million recorded in first-quarter 2003 on contracts for which we elected the normal purchases and sales exception in second-quarter 2003.

Power's costs decreased $2 billion due to a decrease in power and natural gas costs of $1.5 billion and a decrease in crude and refined products costs of $536.4 million. Power and natural gas costs decreased largely due to a 45 percent decrease in power purchase volumes. Second-quarter 2004 reductions to liabilities associated with power marketing activities in California during 2000 and 2001 resulted in gains of $10.4 million, which contributed to the decrease in costs discussed above. Costs in 2004 also reflect a $13 million payment made to terminate a non-derivative power sales contract, which partially offsets the decrease in power and natural gas costs. Crude and refined products costs decreased largely due to the sale of the crude gathering business in 2003 and the continued efforts to exit this line of business.

Selling, general and administrative expenses decreased $44.3 million. Compensation expense declined in 2004 as a result of staff reductions in prior years combined with the accelerated recognition in 2003 of certain deferred compensation arrangements. A $6.3 million reversal of bad debt reserve resulting from the first-quarter 2004 settlement with certain California utilities and the absence of a $6.5 million increase to bad debt reserves associated with a termination settlement in second-quarter 2003 also contributed to the decrease.

Other (income) expense - net in 2003 includes a $175 million gain from the sale of an energy-trading contract partially offset by a $20 million charge for a settlement with the CFTC. Other (income) expense - net in 2004 includes $6.1 million in fees related to the sale of certain receivables to a third party.

GAS PIPELINE

OVERVIEW OF SIX MONTHS ENDED JUNE 30, 2004

In February 2004, Transco placed an expansion into service increasing capacity on its natural gas system by 54,000 Dth/d. As discussed below, Northwest made additional progress towards repairing and restoring a segment of its natural gas pipeline system in western Washington.

Effective June 1, 2004, and due in part to FERC Order 2004, management and decision-making control of certain regulated gas gathering assets was transferred from our Midstream segment to our Gas Pipeline segment. Consequently, the results of operations were similarly reclassified. All prior periods reflect these classifications.

OUTLOOK FOR THE REMAINDER OF 2004

In December 2003, we received an Amended Corrective Action Order (ACAO) from the U.S. Department of Transportation's Office of Pipeline Safety (OPS) regarding a segment of one of our natural gas pipelines in western Washington. The pipeline experienced two breaks in 2003 and we subsequently idled the pipeline segment until its integrity could be assured. The decision to idle the pipeline has not had a significant impact on our ability to meet market demand to date. Primarily because of customer market profiles prior to the summer months, we have been able to meet firm service requirements through our parallel pipeline in the same corridor.

We have successfully hydrotested and returned to service 111 miles of the 268 miles of pipe affected by the ACAO. That effort has restored 131 MDth/day of the 360 MDth/day of idled capacity and is anticipated to be adequate to meet most market conditions. The restored facilities will be monitored and tested as necessary until they are ultimately replaced. Total estimated testing and remediation costs are between $40 and $50 million, including approximately $9 million related to one segment of pipe that we recently determined not to return to service and is thus being expensed in the second quarter.

As currently required by OPS, we plan to replace the pipeline's entire capacity by November 2006 to meet long-term demands. We conducted a reverse open season to determine whether any existing customers were willing to relinquish or reduce their capacity commitments to allow us to reduce the scope of pipeline replacement facilities. That resulted in 13 MDth/day of capacity being relinquished and incorporated into the replacement project. The total costs of the capacity replacement project are expected to be in the range of approximately $310 million to $360 million. The majority of these costs will be spent in 2005 and 2006. We anticipate filing a rate case to recover the capitalized costs relating to restoration and replacement of facilities following the in-service date of the replacement facilities.

PERIOD-OVER-PERIOD RESULTS

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
Segment revenues	$ 331.0	$ 330.7	$ 690.0	$ 670.3
Segment profit	$ 132.8	$ 115.5	$ 280.2	$ 265.8

Three months ended June 30, 2004 vs. three months ended June 30, 2003

The $300,000 increase in Gas Pipeline revenues is due primarily to $14 million of higher transportation revenues associated with expansion projects. The $14 million consists of $10 million at Northwest from an expansion project that became operational in October 2003 (Evergreen) and $4 million higher demand revenues on the Transco system resulting primarily from new expansion projects that became operational in May 2003 (Momentum Phase I), November 2003 (Trenton-Woodbury) and February 2004 (Momentum Phase II). Partially offsetting these increases were $7 million lower revenues from the sale of environmental mitigation credits and $5 million lower transportation revenues ($3 million due to lower short-term firm on Northwest and $2 million due to lower gathering revenue on Transco).

Costs and operating expenses increased $2 million, or one percent, due primarily to a $4 million increase in non-income related taxes, $2 million higher fuel expense at Transco, reflecting a reduction in pricing differentials on the volumes of gas used in operations as compared to 2003. These increases were partially offset by $4 million reduction of depreciation, depletion and amortization expense related to environmental mitigation credits.

Other (income) expense - net in 2004 includes a $9 million charge for the write-off of previously-capitalized costs incurred on an idled segment of Northwest's system that we recently determined will not be returned to service. Other (income) expense - net in 2003 includes a $25.5 million charge at Northwest to write off capitalized software development costs for a service delivery system following a decision not to implement.

The $17.3 million, or 15 percent, increase in Gas Pipeline segment profit is due primarily to the absence of the $25.5 million charge in 2003 discussed above and $3.2 million higher equity earnings (included in Investing income (loss)). These items were partially offset by the $9 million charge discussed above and the $2 million increase in costs and operating expenses. The increase in equity earnings includes a $3 million increase in earnings from our investment in Gulfstream Natural Gas System (Gulfstream).

Six months ended June 30, 2004 vs. six months ended June 30, 2003

The $19.7 million, or three percent, increase in Gas Pipeline revenues is due primarily to $32 million higher transportation revenues associated with expansion projects. The $32 million consists primarily of $20 million at Northwest from an expansion project that became operational in October 2003 (Evergreen) and $12 million higher demand revenues on the Transco system resulting from new expansion projects that became operational in May 2003 (Momentum Phase I), November 2003 (Trenton-Woodbury) and February 2004 (Momentum Phase II). Revenues also increased due to $17 million higher gas exchange imbalance settlements (offset in costs and operating expenses). Partially offsetting these increases were $9 million lower revenues associated with tracked costs, which are passed through to customers (substantially offset in costs and operating expenses), $8 million lower revenues from the sale of environmental mitigation credits and $8 million lower transportation revenues ($5 million due to lower short-term firm on Northwest and $3 million due to lower gathering revenues on Transco).

Costs and operating expenses increased $26 million, or eight percent, due primarily to $17 million higher gas exchange imbalance settlements (offset in revenues), $11 million higher fuel expense at Transco, reflecting a reduction in pricing differentials on the volumes of gas used in operations as compared to 2003 and $7 million higher expenses related to operations and maintenance expenses. These increases were partially offset by $8 million lower recovery of tracked costs which are passed through to customers (offset in revenues), a $5 million reduction of depreciation, depletion and amortization expense related to environmental mitigation credits and a $4 million reduction of expense in first-quarter 2004 related to an adjustment to depreciation recognized in a prior period.

Other (income) expense - net in 2004 includes a $9 million charge for the write-off of previously-capitalized costs incurred on an idled segment of Northwest's system that we recently determined will not be returned to service. Other (income) expense - net in 2003 includes a $25.5 million charge at Northwest to write off capitalized software development costs for a service delivery system following a decision not to implement.

The $14.4 million, or five percent, increase in Gas Pipeline segment profit is primarily due to the absence of the $25.5 million charge in 2003 discussed above, $19.7 million higher revenues and $5.2 million higher equity earnings (included in Investment income (loss)). These increases were partially offset by the $26 million higher costs and operating expenses and the $9 million charge discussed above. The increase in equity earnings is primarily due to a $5.4 million increase in earnings from our investment in Gulfstream.

EXPLORATION & PRODUCTION

OVERVIEW OF THE SIX MONTHS ENDED JUNE 30, 2004

Domestic average daily production volumes increased 14 percent from the beginning of the year. Domestic average daily production was approximately 511 million cubic feet of gas equivalent at June 30, 2004, compared to 450 million cubic feet at the beginning of the year, and has surpassed production levels reached prior to the asset sales of 2003. The increase is a result of the company successfully contracting additional drilling rigs, particularly in the Piceance basin, to increase our development drilling. Additionally, the Piceance drilling program has improved the efficiency time to drill a well and start another one, increasing the number of wells drilled in a particular period of time and bringing new production on line more quickly. Additional rigs were also added to the other core areas of San Juan, Arkoma and Powder River basins. The benefit of these higher volumes was offset by hedge losses and increasing costs, including a loss provision related to an ownership dispute on prior period production.

OUTLOOK FOR THE REMAINDER OF 2004

Our expectations for the remainder of the year include:

- A continuing development drilling program in our key basins with an increase in activity in the Piceance basin.

- Increasing our beginning of the year production level 15 percent by the end of 2004. Approximately 78 percent of our forecasted production for the remainder of 2004 is hedged at prices that average $3.69 per mcfe at a basin level.

The following discussions of the quarter-over-quarter and year-to-date comparative results primarily relate to our continuing operations. However, the results for 2003 include those operations that were sold during 2003 that did not qualify for discontinued operations reporting. Those properties consist of the Uinta and Denver Julesberg basins and certain additional properties in the Green River and San Juan basins. The operations classified as discontinued operations are the properties in the Hugoton and Raton basins.

PERIOD-OVER-PERIOD RESULTS

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
Segment revenues	$ 189.0	$ 200.2	$ 354.2	$ 444.1
Segment profit	$ 43.3	$ 178.7	$ 94.8	$ 292.5

Three months ended June 30, 2004 vs. three months ended June 30, 2003

The $11.2 million, or six percent, decrease in Exploration & Production revenues is due primarily to lower income on derivative instruments that did not qualify for hedge accounting, and lower income from the utilization of excess transportation capacity. These decreases are partially offset by an increase in revenues from gas management activities.

Domestic production revenues increased slightly from the prior period. Net realized average prices include the effect of hedge positions. Production volumes increased slightly from period to period while net realized prices were lower than the prior period. We expect volumes to continue to increase during the remainder of the year as our drilling program continues.

To minimize the risk and volatility associated with the ownership of producing gas properties, we enter into derivative forward sales contracts which economically lock in a price for a portion of our future production. Approximately 76 percent of domestic production in the second quarter of 2004 was hedged. These hedging decisions are made considering our overall commodity risk exposure.

Costs and expenses, including selling, general and administrative expenses, increased $19 million, primarily reflecting the following:

- $7 million higher lease operating expense associated with the increase of well maintenance activities, higher labor and fuel costs and an increase in overhead payments to another operator;
- $6 million higher gas management expenses associated with the higher revenues from gas management activities;
- $2 million higher depreciation, depletion, and amortization expense primarily as a result of higher production volumes; and
- a $2 million increase in operating taxes primarily as a result of higher production volumes.

The $135.4 million decrease in segment profit is due primarily to the gain on the sale of properties of $91.5 million in the second quarter of 2003. Additionally, there were lower revenues related to excess transportation capacity and non-hedge derivative income in 2004. In addition, a loss provision of $11.3 million was recorded to Other (income) expense - net during the second quarter of 2004 related to an ownership dispute on prior period production.

Six months ended June 30, 2004 vs. six months ended June 30, 2003

The $89.9 million, or 20 percent, decrease in Exploration & Production's revenues is primarily due to the $45 million lower domestic production revenues reflecting lower net realized average prices and lower production volumes. The remainder of the decrease reflects a reduction in revenues from gas management activities, lower income from the utilization of excess transportation capacity, and lower income on derivative instruments that did not qualify for hedge accounting.

The decrease in domestic production revenues reflects $35 million lower revenues associated with a three percent decrease in net domestic production volumes and $10 million lower revenues associated with a 12 percent decrease in net realized average prices for production sold. The decrease in production volumes primarily results from the sales of properties in 2003, partially offset by increased production volumes for properties retained.

Costs and expenses, including selling, general and administrative expenses, decreased $1 million primarily reflecting the following:

- $7 million lower gas management expenses associated with the lower revenues from gas management activities;
- $3 million lower selling, general and administrative expenses as a result of assets sold in 2003;
- $2 million lower depreciation, depletion, and amortization expense as a result of decreased volumes; and
- $8 million higher lease operating expense.

Other (income) expense - net includes $91.5 million in net gains on the sale of assets during 2003.

The $197.7 million decrease in segment profit is due primarily to the absence of $92 million in net gains on the sales of assets in 2003, a decrease in net domestic production volumes resulting from the assets sold in 2003, and lower net realized average prices. Additionally, a loss provision of $11.3 million was recorded to Other (income) expense - net during the second quarter of 2004 related to an ownership dispute on prior period production.

MIDSTREAM GAS & LIQUIDS

OVERVIEW OF SIX MONTHS ENDED JUNE 30, 2004

Consistent with our strategy to invest in growth areas where we have large scale assets and divest non-core assets, we placed into service additional infrastructure in the deepwater offshore area of the Gulf of Mexico and expanded the Opal gas processing facility in Wyoming. In the deepwater Gulf of Mexico, the Devils Tower production handling facility, the Canyon Chief gas pipeline, and the Mountaineer oil pipeline began flowing product in May 2004, while the Gunnison oil pipeline volumes have been increasing since the first of the year. These deepwater assets contributed approximately $13 million to segment profit in the second quarter. Additionally, the Opal expansion began operating in the first quarter of 2004.

We have made significant progress on our asset sale program. We recently announced the execution of purchase and sale agreements for the sale of our western Canadian Straddle Plants and certain South Texas gas pipelines (owned by Transco Gas Pipeline). These transactions are expected to yield approximately $565 million in U.S. funds. The Canadian sale closed in July 2004 and the South Texas sale is pending FERC approval and is expected to close in the fourth-quarter of 2004. We continue to negotiate with counterparties for the sale of Gulf Liquids and the ethylene distribution business in Louisiana.

OUTLOOK FOR THE REMAINDER OF 2004

The following factors could impact our business in the remaining quarters of 2004 and beyond:

- Continued growth in the deepwater areas of the Gulf of Mexico is expected to contribute to, and become a larger component of our future segment revenues and segment profit. We expect these additional fee-based revenues to lower our overall exposure to commodity price risks. Revenues related to the Gunnison and Devils Tower deepwater projects are expected to continue growing throughout 2004 and make a contribution to annual segment profit in 2004.

- Our domestic gas processing margins benefited from strong crude oil prices in the first six months of 2004 and achieved five-year annual average. Since natural gas and crude oil markets are highly volatile, our processing margins in the first half of 2004 are not necessarily indicative of levels expected for the remainder of 2004.

- Beginning in the second quarter of 2003, our Gulf Coast gas processing plants earned additional fee revenues from short-term processing agreements contracted in response to gas merchantability orders from pipeline operators requiring producers' gas to be processed to achieve pipeline quality standards. These contracts could be terminated as a result of a shift in regulatory policy or a sustained, long-term period of favorable gas processing margins. The termination of these short-term contracts could result in lower Gulf Coast processing revenues.

- We have requested a waiver from the FERC regarding compliance with FERC Order 2004 for the management of Discovery Gas Transmission and Black Marlin assets. In July, the FERC granted a partial waiver allowing our Midstream segment to continue to manage these assets subject to the remaining procedural requirements of the FERC order. We continue to evaluate the details of the partial waiver and our compliance with the remaining requirements. Transfer of management of these assets would result in lower segment profit for Midstream, but Williams consolidated operating profit would remain unchanged.

- Our Venezuelan assets were constructed and are currently operated for the exclusive benefit of Petroleos de Venezuela S.A. (PDVSA), the state owned Petroleum Corporation of Venezuela. The Venezuelan economic and political environment can be volatile, but has not significantly impacted the cash flows of our facilities to date. However, the upcoming referendum on the Presidency of Hugo Chavez may create a higher degree of risk than we have experienced to date. PDVSA is applying increased pressure on the terms of operating contracts with vendors like and including ourselves.

During second-quarter 2004, we reclassified the operations of the Canadian Straddle Plants to discontinued operations. In July 2004, we completed the sale of these assets for approximately $536 million in U.S. funds. The estimated pre-tax gain on sale of approximately $190 million will be recorded in the third quarter of 2004. Additionally, the Canadian liquids system and Gulf Liquids continue to be classified as discontinued operations. Effective June 1, 2004, and due in part to FERC Order 2004, management and decision-making control of certain regulated gas gathering assets was transferred from our Midstream segment to our Gas Pipeline segment. Consequently, the results of operations were similarly reclassified. All prior periods reflect these classifications.

On July 20, 2004, Wilpro Energy Services (PIGAP II) Limited, one of our subsidiaries, received a notice of default from the Venezuelan state oil company, PDVSA, relating to certain operational issues alleging that our subsidiary is not in compliance under a services agreement. We do not believe a basis exists for such notice and are contesting the giving of this notice. Although this notice of default could result in an event of default with respect to project loans totaling approximately $219 million and could result in an adverse effect with respect to other of our debt instruments, we believe that we will be able to resolve any issues arising from the alleged notice of default without any such results occurring with respect to our other debt instruments. The lenders under the project loan agreement have confirmed to us in writing that based on the facts they currently know, they have no intention of exercising any rights or remedies under the project loan agreement until the issues raised in the notice and our response are clarified.

PERIOD-OVER-PERIOD RESULTS

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
Segment revenues	$ 630.5	$ 502.2	$ 1,257.8	$ 1,367.6
Segment profit (loss)				
Domestic Gathering & Processing	$ 76.7	$ 59.1	$ 154.9	$ 159.7
Venezuela	19.4	20.0	40.9	33.5
Other	3.4	(21.9)	11.3	(23.2)
Total	$ 99.5	$ 57.2	$ 207.1	$ 170.0

Three months ended June 30, 2004 vs. three months ended June 30, 2003

The $128.3 million increase in Midstream's revenues is primarily the result of favorable gas processing and olefins production economics. Revenues associated with natural gas liquids (NGLs) and olefins products increased $123 million due to significantly higher production volumes and slightly higher market prices. Included within the $123 million increase are revenues associated with our deepwater assets, including our recently completed infrastructure, which generated $18 million in higher fee revenue. In addition, revenues increased $81 million as the result of marketing natural gas liquids (NGLs) on behalf of our customers. Before 2004, our purchases of customers' NGLs were netted within revenues. In 2004, these purchases of customers' NGLs are reported in costs and operating expenses which substantially offsets the change in revenues. These revenue increases are largely offset by lower trading revenues resulting from the fourth-quarter 2003 sale of our wholesale propane business.

Costs and operating expenses increased $101 million primarily due to the higher cost of natural gas and ethene required to produce NGL and olefins. Natural gas purchases used to replace the heating value of NGLs extracted at our gas processing facilities increased $78 million while feedstock for olefins production increased $12 million. Higher NGL production volumes also resulted in $9 million in higher transportation and fractionation expenses. Maintenance costs, additional depreciation expense, and other product purchases increased approximately $22 million. With a similar impact to sales, total costs and operating expenses increased $81 million due to the marketing of NGLs on behalf of customers. These higher costs and operating expenses are largely offset by lower trading purchases due to the sale of our wholesale propane business noted above.

The $42.3 million increase in Midstream segment profit for the second quarter of 2004 is primarily the result of improved results at our domestic gathering and processing business and at our olefins facilities. A more detailed analysis of segment profit of Midstream's various operations is presented below.

Domestic Gathering & Processing: The $17.6 million increase in domestic gathering and processing segment profit includes an increase of $13.6 million in the Gulf Coast region's segment profit and a $4.0 million increase in the West region.

Segment profit for our Gulf Coast region increased $13.6 million as a result of incremental profits from newly constructed assets in the deepwater area of the Gulf of Mexico. The Devils Tower production handling facility, the Canyon Chief gas pipeline, and the Mountaineer oil were all placed into service at the end of the first quarter of 2004.

Our West Region's segment profit increased $4 million reflecting improved gas processing margins offset by lower fee revenues and higher operating expenses. Following are certain material components of the increase:

- Our gas processing margins increased $12 million due to higher NGL volumes and higher NGL prices supported by significantly higher crude prices. The increase in NGL revenues was partially offset by higher natural gas purchases caused by higher volumes and market prices.

- Fee revenues for gathering and processing services declined $5 million as a result of slightly lower rates and volumes in the Four Corners area.

- Maintenance expenses increased $5 million primarily due to additional scheduled maintenance projects at the San Juan and Wyoming facilities.

Venezuela: Segment profit for our Venezuelan assets in the second quarter of 2004 remained consistent with the second quarter of 2003.

Other: With improved olefins fractionation margins, results from our NGL trading, fractionation, and storage business, olefins businesses, and partnership investments increased $25.3 million. Primary drivers of these results are as follows:

- Segment profit for our NGL trading, fractionation, and storage business increased $10 million primarily due to $7 million higher net trading revenues. The improvement in net trading revenues is largely due to the absence of charges totaling $5 million recognized in 2003 for inventory hedge losses and adjustments. Our trading revenues also reflect a $2 million gain generated by rising NGL market prices while our production barrels are being transported to market. Selling, general and administrative expense was $2 million lower in the second-quarter 2004, primarily as a result of the fourth-quarter 2003 sale of our wholesale propane business.

- Segment profit for our olefins businesses increased $17 million. Domestic olefins fractionation margins improved $8 million reflecting the significant strengthening of the ethylene market in 2004 resulting from lower ethylene inventories and higher demand for olefins products. As a result, our domestic olefins business increased its volume of spot sales significantly. In addition, margins were improved by a new higher fixed margin contract. The $9 million improvement from our Canadian Olefins group is largely attributable to $6 million in higher olefins fractionation margins.

Six months ended June 30, 2004 vs. six months ended June 30, 2003

The $109.8 million decrease in Midstream's revenue is primarily the result of lower trading revenues primarily due to the fourth-quarter 2003 sale of our wholesale propane business. This decline was largely offset by higher revenues from all of Midstream's current businesses. Revenue from the sale of NGLs and olefins products increased $177 million due to significantly higher production volumes and slightly higher market prices as a result of improving market conditions in 2004. Included within the $177 million increase are revenues associated with our deepwater assets, including our recently completed infrastructure, which generated $21 million in higher fee revenue. Additionally, sales of NGLs increased $128 million as a result of marketing of NGLs on behalf of our customers. Before 2004, our purchases of customers' NGLs were netted within revenues. In 2004, these purchases of customers' NGLs are reported in costs and operating expenses, which substantially offsets the change in revenues.

Cost and operating expenses declined $120.9 million primarily as a result of lower trading costs due to the sale of our wholesale propane business. This decline was partially offset by higher costs relating to the increase in NGL and olefins production noted above. Natural gas purchases used to replace the heating value of NGLs extracted at our gas processing facilities increased $117 million and feedstock for olefins production increased $39 million. Higher NGL production volumes also resulted in $8 million in higher transportation and fractionation expenses. Maintenance costs, additional depreciation expense, and other product purchases increased approximately $25 million. With a similar impact to sales, total costs and operating expenses increased $128 million due to the marketing of NGLs on behalf of customers.

The $37.1 million increase in Midstream segment profit for the first six months of 2004 is due primarily to improved olefins production margins and higher deepwater profits. These increases are partially offset by lower gas processing margins and lower gathering and processing fee income. A more detailed analysis of segment profit of Midstream's various operations is presented below.

Domestic Gathering & Processing: The $4.8 million decrease in our domestic gathering and processing segment profit includes a $20.1 million decline in the West region partially offset by a $15.3 million increase in our Gulf Coast region.

Our West region's segment profit declined $20.1 million primarily due to lower gas processing margins, lower gathering and processing fee revenues, and higher operating expenses. Following are certain material components of the decrease.

- Although still above 5-year averages, gas processing margins in the first six months of 2004 declined $9 million from the level recorded in the same period in 2003. Higher market prices for natural gas used to replace the heating value of NGLs extracted at our processing plants negatively impacted our processing margins. This increase in natural gas prices is largely due to the absence of depressed Wyoming natural gas prices caused by regional transportation constraints in the first quarter of 2003. This impact of higher natural gas prices is partially offset by significantly higher NGL prices in 2004 supported by strong crude prices.

- Gathering and processing fee revenues declined $12 million primarily due to fewer customers electing the fee-based billing option of processing contracts and slightly lower rates and volumes in the Four Corners area.

- Maintenance expenses increased $8 million primarily due to additional scheduled maintenance projects at the San Juan and Wyoming facilities.

- Other revenues increased $4 million primarily due to higher gas treating fees on our southwest Wyoming facilities.

Segment profit for our Gulf Coast Region increased $15.3 million primarily as a result of newly constructed assets in the deepwater area of the Gulf of Mexico. The Devils Tower production handling facility, the Canyon Chief gas pipeline, and the Mountaineer oil were all placed into service at the end of the first quarter of 2004. In addition, gas processing margins increased as a result of new processing agreements created to allow producers' gas to be processed to achieve pipeline quality standards.

Venezuela: The $7.4 million increase in segment profit for our Venezuelan assets is primarily due to the absence of a fire at the El Furrial facility that reduced revenues by $10 million in the first quarter of 2003. In addition, lower equity earnings from our investment in the Accroven partnership and higher currency revaluation expenses negatively impacted segment profit.

Other: As a result of improved olefins fractionation margins, results from our NGL trading, fractionation, and storage business; olefins businesses; and partnership investments increased $34.5 million, as follows:

- Segment profit for our NGL trading, fractionation, and storage business increased $4 million primarily due to $4 million in lower selling, general and administrative expense resulting from the fourth-quarter 2003 sale of our wholesale propane business.

- Segment profit for the olefins businesses increased $24 million. Domestic olefins fractionation margins improved $12 million reflecting the significant strengthening of the ethylene market in 2004 created as a result of lower ethylene inventories and higher demand for olefins products. As a result, our domestic olefins business increased its volume of spot sales significantly. In addition, margins were improved by a new higher fixed margin contract. Segment profit from our Canadian olefins business increased $12 million largely due to $6 million in higher olefins fractionation margins. Currency translation adjustments were $4 million favorable as a result of a strengthening Canadian dollar.

- Our earnings from partially owned domestic assets accounted for using the equity method increased $6 million largely due to the absence of items impacting earnings of partnerships in 2003. This 2003 activity includes $12 million in charges associated with accounting adjustments recorded at the Discovery partnership, a $5 million gain on the sale of our investment in Rio Grande Pipeline partnership, and the absence of approximately $4 million in earnings generated from investments that were sold after the second quarter of 2003.

OTHER

	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
	2004	2003	2004	2003
	(MILLIONS)		(MILLIONS)	
Segment revenues	$ 7.0	$ 20.1	$ 19.6	$ 48.1
Segment loss	$ (14.3)	$ (51.7)	$ (23.0)	$ (46.9)

Other segment revenues for the three and six months ended June 30, 2003 includes approximately $8 million and $22 million, respectively, of revenues related to certain butane blending assets, which were sold during third-quarter 2003.

Other segment loss for the three and six months ended June 30, 2004 includes a $10.8 million impairment of our investment in Longhorn. The charge reflects management's belief that there was an other than temporary decline in the fair value of this investment following a determination that additional funding would be required to commission the pipeline into service. The project incurred cost overruns in preparation for commissioning, including higher priced line fill costs and is expected to become operational before the end of 2004. Other segment loss for the six months ended June 30, 2004 includes $6.5 million net unreimbursed advisory fees related to the recapitalization of Longhorn in February 2004. If the project achieves certain future performance measures, the unreimbursed fees may be recovered. As a result of this recapitalization, we sold a portion of our equity investment in Longhorn for $11.4 million, received $58 million in repayment of a portion of our advances to Longhorn and converted the remaining advances, including accrued interest, into preferred equity interests in Longhorn. These preferred equity interests are subordinate to the preferred interests held by the new investors. Other than the unreimbursed fees, no gain or loss was recognized on this transaction.

Other segment loss for the three and six months ended June 30, 2003 includes a $42.4 million impairment related to the investment in equity and debt securities of Longhorn.

FAIR VALUE OF TRADING DERIVATIVES

The chart below reflects the fair value of derivatives held for trading purposes as of June 30, 2004. We have presented the fair value of assets and liabilities by the period in which we expect them to be realized.

ASSETS (LIABILITIES)				
TO BE REALIZED IN 1-12 MONTHS (YEAR 1)	TO BE REALIZED IN 13-36 MONTHS (YEARS 2-3)	TO BE REALIZED IN 36-60 MONTHS (YEARS 4-5)	TO BE REALIZED IN 61-120 MONTHS (YEARS 6-10)	TOTAL FAIR VALUE
(MILLIONS)				
$ (31)	$ 17	$ (8)	$ 1	$ (21)

As the table above illustrates, we are not materially engaged in trading activities. However, we hold a substantial portfolio of non-trading derivative contracts. Non-trading derivative contracts are those that hedge or could possibly hedge Power's long-term structured contract position and the activities of our other segments on an economic basis. Certain of these economic hedges have not been designated as or do not qualify as SFAS No. 133 hedges. As such, changes in the fair value of these derivative contracts are reflected in earnings. We also hold certain derivative contracts, which do qualify as SFAS No. 133 cash flow hedges, which primarily hedge Exploration & Production's forecasted natural gas sales. As of June 30, 2004, the fair value of these non-trading derivative contracts was a net asset of $234 million.

COUNTERPARTY CREDIT CONSIDERATIONS

We include an assessment of the risk of counterparty non-performance 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 June 30, 2004, we held collateral support of $338 million.

We also enter into netting agreements to mitigate counterparty performance and credit risk. During second-quarter 2004, we did not incur any significant losses due to recent counterparty bankruptcy filings.

The gross credit exposure from our derivative contracts as of June 30, 2004 is summarized below.

COUNTERPARTY TYPE	INVESTMENT GRADE(A)	TOTAL
	(MILLIONS)	
Gas and electric utilities	$ 667.9	$ 780.5
Energy marketers and traders	2,446.9	4,843.7
Financial institutions	1,343.4	1,343.4
Other	434.2	438.5
	$ 4,892.4	7,406.1
Credit reserves		(34.2)
Gross credit exposure from derivatives(b)		$ 7,371.9

We assess our credit exposure on a net basis. The net credit exposure from our derivatives as of June 30, 2004 is summarized below.

COUNTERPARTY TYPE	INVESTMENT GRADE(A)	TOTAL
	(MILLIONS)	
Gas and electric utilities	$ 130.2	$ 145.5
Energy marketers and traders	527.8	792.3
Financial institutions	191.5	191.5
Other	2.9	3.9
	$ 852.4	1,133.2
Credit reserves		(34.1)
Net credit exposure from derivatives(b)		$ 1,099.1

(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.

(b) One counterparty within the California power market represents more than ten percent of the derivative assets and is included in investment grade. Standard & Poor's and Moody's Investors Service do not currently rate this counterparty. We included this counterparty in the investment grade column based upon contractual credit requirements in the event of assignment or substitution of a new obligation for the existing one.

FINANCIAL CONDITION AND LIQUIDITY

LIQUIDITY

Overview

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, we successfully executed certain critical components of our plan during 2003. Key execution steps for 2004 and beyond, and our progress to date, include the following:

1) Completion of planned asset sales, which we estimated would generate proceeds of approximately $800 million in 2004.

   - On March 31, 2004, we completed the sale of our Alaska refinery and related assets for approximately $304 million.

   - On July 28, 2004, we completed the sale of three straddle plants in western Canada for approximately $536 million.

   - In addition to these transactions, we expect to generate additional proceeds from the sale of assets of approximately $50 to $100 million.

2) Additional reduction of our selling, general and administrative costs.

   - On June 1, 2004, we announced an agreement with IBM Business Consulting Services (IBM) to aid us in transforming and managing certain areas of our accounting, finance and human resources processes. In addition, IBM will manage key aspects of our information technology, including enterprise wide infrastructure and application development. The 7 1/2 year agreement began July 1, 2004 and is expected to reduce costs in these areas while maintaining a high quality of service.

3) The replacement of our cash-collateralized letter of credit and revolver facility with facilities that do not encumber cash.

   - In April 2004, we entered into two unsecured bank revolving credit facilities totaling $500 million. These facilities provide for both borrowings and letters of credit, but are used primarily for issuing letters of credit. Use of these new facilities released approximately $500 million of restricted cash, restricted investments and margin deposits in the second quarter. Also, on May 3, 2004 we entered into a new three-year, $1 billion secured revolving credit facility which is available for borrowings and letters of credit. Northwest and Transco have access to $400 million each under the facility, which is secured by certain Midstream assets and a guarantee from WGP (see Note 12 of Notes to the Consolidated Financial Statements).

4) Continuation of our efforts to exit from the Power business.

   - We continue to evaluate alternatives and discuss our plans and operating strategy for the Power business with our Board of Directors. As an alternative to continuing a plan of pursuing a complete exit from the Power business, we are evaluating whether the benefits of realizing the positive cash flow expected to be generated by this business through continued ownership exceed the benefits of a sale at a depressed price. If we pursue this alternative, we expect to continue our current program of managing this business to minimize financial risk, generate cash and manage existing contractual commitments.

Sources of liquidity

Our liquidity is derived from both internal and external sources. Certain of those sources are available to us (at the parent level) and others are available to certain of our subsidiaries.

At June 30, 2004, we have the following sources of liquidity from cash and cash equivalents:

- Cash-equivalent investments at the corporate level of $794 million as compared to $2.2 billion at December 31, 2003.

- Cash and cash-equivalent investments of various international and domestic entities of $236 million, as compared to $91 million at December 31, 2003.

At December 31, 2003, we had capacity of $447 million available under the $800 million revolving and letter of credit facility. This facility was terminated on May 3, 2004. At June 30, 2004, we have capacity of $11 million available under the two unsecured revolving credit facilities totaling $500 million and $819 million available under our $1 billion secured revolving facility. We also have a commitment from our agent bank to expand our credit facility by an additional $275 million.

We have an effective shelf registration statement with the Securities and Exchange Commission that authorizes us to issue an additional $2.2 billion of a variety of debt and equity securities. However, the ability to utilize this shelf registration for debt securities is restricted by certain covenants of our debt agreements.

In addition, our wholly owned subsidiaries Northwest and Transco have outstanding registration statements filed with the Securities and Exchange Commission. As of June 30, 2004, approximately $350 million of shelf availability remains under these registration statements. However, the ability to utilize these registration statements is restricted by certain covenants associated with our $800 million 8.625 percent senior unsecured notes. Interest rates, market conditions, and industry conditions will affect amounts raised, if any, in the capital markets.

During the first six months of 2004, we satisfied liquidity needs with:

- $304 million in cash generated from the sale of the Alaska refinery and related assets, and

- $603.6 million in cash generated from operating activities of continuing operations, including the release of approximately $500 million of restricted cash, restricted investments and margin deposits previously used to collateralize certain credit facilities.

Credit ratings

As part of executing the business plan announced in February, 2003, we established a goal of returning to investment grade status. While reduction of debt is viewed as a key contributor towards this goal, certain of the key credit rating agencies have imputed the financial commitments associated with our long-term tolling agreements within the Power business as debt. If we are unable to achieve our goal of exiting the Power business or otherwise eliminating these commitments, obtaining an investment grade rating may be further delayed. See Note 1 of Notes to Consolidated Financial Statements for a further discussion on the status of the Power business.

On July 30, 2004, Standard & Poor's raised our debt ratings outlook to stable from negative citing our debt reductions efforts. If we continue to reduce debt in line with forecasts, our rating could improve over the three-year horizon of the outlook. An improved rating could result in lower borrowing costs. However, if financial ratios fall considerably below expectations, the outlook and the rating could decline.

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

As discussed previously, in April 2004, we entered into two unsecured bank revolving credit facilities totaling $500 million. We were able to obtain the unsecured credit facilities because the funding bank syndicated its associated credit risk into the institutional investor market via a Rule 144A offering, which allows for the sale of certain restricted securities only to qualified institutional buyers. Upon the occurrence of certain credit events, letters of credit outstanding under the agreement become cash collateralized, creating a borrowing under the facilities. Concurrently the bank can deliver the facilities to the institutional investors, whereby the investors replace the bank as lender under the facilities.

To facilitate the syndication of the facilities, the bank established trusts funded by the institutional investors. The assets of the trusts serve as collateral to reimburse the bank for our borrowings in the event the facilities are delivered to the investors. We have no asset securitization or collateral requirements under the new facilities. During the second quarter, use of these new facilities released approximately $500 million of restricted cash, restricted investments and margin deposits (see Note 12 of Notes to the Consolidated Financial Statements).

OPERATING ACTIVITIES

For the six months ended June 30, 2004, we recorded approximately $30 million in Provision for loss on investments, property and other assets consisting primarily of a $10.8 million impairment of our investment in Longhorn and a $9 million write off of previously-capitalized costs incurred on an idled segment of Northwest's system.

For the six months ended June 30, 2003, we recorded approximately $121 million in Provision for loss on investments, property and other assets consisting primarily of a $42.4 million impairment of our investment in Longhorn, a $25.5 million write-off of software development costs at Northwest, a $13.5 million impairment of an investment in a company holding phosphate reserves and a $12 million impairment of Algar Telecom S.A.

The net gain on disposition of assets in second quarter 2003 primarily consists of the gains on the sales of natural gas properties.

In 2003, we recorded an accrual for fixed rate interest included in the RMT Note on the Consolidated Statement of Cash Flows representing the quarterly non-cash reclassification of the deferred fixed rate interest from an accrued liability to the RMT Note. The amortization of deferred set-up fee and fixed rate interest on the RMT Note relates to amounts recognized in the income statement as interest expense, which were not payable until maturity. The RMT Note was repaid in May 2003.

In the first quarter of 2004, we recognized net cash used by operating activities of discontinued operations in the Consolidated Statement of Cash Flow of $47.1 million. Included in this amount was approximately $70 million in use of funds related to the timing of settling working capital issues of the Alaska refinery and related assets. In the second quarter of 2004, we received the proceeds from the collection of approximately $58 million in trade receivables related to the Alaska refinery and related assets.

FINANCING ACTIVITIES

On March 15, 2004, we retired the remaining $679 million obligation pertaining to the outstanding balance of the 9.25 percent senior unsecured Notes due March 15, 2004. The $679 million represented the remaining amount of the Notes subsequent to the fourth-quarter 2003 tender which retired $721 million of the original $1.4 billion balance.

In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of a specified series of our outstanding notes and debentures. As of the June 8, 2004, tender offer expiration date, we accepted for purchase tenders of notes and debentures with an aggregate principal amount of approximately $1.17 billion. The payment of these notes and debentures in second-quarter 2004 is recorded as Payments of long term debt on the Consolidated Statement of Cash Flows. In May 2004, we also repurchased on the open market debt of approximately $255 million of various notes with maturity dates ranging from 2006 to 2011. In conjunction with the tendered notes, related consents, and the debt repurchase, we paid premiums of approximately $79 million. The premiums, as well as related fees and expenses, together totaling $96.8 million, were recorded in Early debt retirement costs.

In June 2004, we made a payment of approximately $109 million for accrued interest, short-term payables, and long-term debt to repurchase certain receivables from the California Power Exchange that were previously sold to a third party. Approximately $79 million of the payment is included in payments of long-term debt on the Consolidated Statement of Cash Flows. In July 2004, we received payment of approximately $104 million from the California Power Exchange which will be reported in cash flows from operations in the third quarter.

For a discussion of other borrowings and repayments in 2004, see Note 12 of Notes to Consolidated Financial Statements.

Dividends paid on common stock are currently $.01 per common share on a quarterly basis and totaled $10.4 million for the six months ended June 30, 2004. One of the covenants under the indenture for the $800 million senior unsecured notes due 2010 currently limits our quarterly common stock dividends to not more than $.02 per common share. This restriction will be removed in the future if certain requirements in the covenants are met.

INVESTING ACTIVITIES

During the first four months of 2004, we purchased $471.8 million of restricted investments comprised of U.S. Treasury notes and received proceeds on maturity of $851.4 million of such investments on their scheduled maturity date. We made these purchases to satisfy the 105 percent cash collateralization requirement in the $800 million revolving credit facility. This facility was terminated May 3, 2004, subsequent to us entering into the $1 billion secured revolving credit facility (see Note 12 of Notes to Consolidated Financial Statements).

During February 2004, we participated in a recapitalization plan completed by Longhorn. As a result of this plan, we received $58 million in repayment of a portion of our advances to Longhorn and converted the remaining advances, including accrued interest, into preferred equity interests in Longhorn. The $58 million received is included in Proceeds from dispositions of investments and other assets.

The following sales in the first half of 2004 and in 2003 provided significant proceeds and may include various adjustments subsequent to the actual date of sale.

In 2004:

- $304 million related to the sale of Alaska refinery, retail and pipeline and related assets.

In 2003:

- $793 million related to the sale of Texas Gas Transmission Corporation,
- $431 million (net of cash held by Williams Energy Partners) related to the sale of our general partnership interest and limited partner investment in Williams Energy Partners,
- $452 million related to the sale of the Midsouth refinery,
- $417 million related to certain natural gas exploration and production properties in Kansas, Colorado and New Mexico,
- $188 million related to the sale of the Williams travel centers,
- $60 million related to the sale of our equity interest in Williams Bio-Energy L.L.C., and
- $40 million related to the sale of the Worthington facility.

CONTRACTUAL OBLIGATIONS

As discussed in our Annual Report on Form 10-K for the year ended December 31, 2003, we had certain contractual obligations at December 31, 2003, with various maturity dates, related to the following:

- notes payable,
- long-term debt,
- capital and operating leases,
- purchase obligations, and
- other long-term liabilities, including physical and financial derivatives.

During the first six months of 2004, the amount of our contractual obligations changed significantly due to the following:

- On March 15, 2004, we retired the remaining $679 million outstanding balance of the 9.25 percent senior unsecured notes due March 15, 2004.

- In May 2004, we made cash tender offers for approximately $1.34 billion aggregate principal amount of our specified series of outstanding notes and debentures. As of the June 8, 2004, tender offer expiration date, we had accepted for purchase tenders of notes and debentures with an aggregate principal amount of approximately $1.17 billion.

- In May 2004, we repurchased debt of approximately $255 million of various notes with maturity dates ranging from 2006 to 2011.

- On May 27, 2004, we were released from certain historical indemnities, primarily related to environmental remediation, for an agreement to pay $117.5 million (see Note 13 of Notes to Consolidated Financial Statements). We had previously deferred $113 million of a gain on sale in anticipation of costs related to these indemnities. At June 30, 2004, the net present value of this settlement is $107.5 million. Of this amount, $35 million is classified as current and was subsequently paid on July 1, 2004. The remaining amount will be paid in three installments of $27.5 million, $20 million, and $35 million in 2005, 2006, and 2007, respectively.

- Power's physical and financial derivative obligations decreased by approximately $1.2 billion. The decrease is due to normal trading and market activity and the expiration of certain long-term power contracts in the first six months of 2004.

- As part of the sale of the Alaska refinery, we terminated a $385 million crude purchase contract with the state of Alaska.

OUTLOOK FOR THE REMAINDER OF 2004

We estimate capital and investment expenditures will be approximately $775 million to $875 million for 2004. During the remainder of 2004, we expect to fund capital and investment expenditures, debt payments and working-capital requirements through (1) cash and cash equivalent investments on hand, (2) cash generated from operations, and (3) cash generated from the sale of assets. In first-quarter 2004, we completed the sale of our Alaska refinery and related assets for approximately $304 million. On July 28, 2004, we completed the sale of three straddle plants in western Canada for approximately $536 million. In addition to these transactions, we currently expect to generate additional proceeds from the sale of assets of approximately $50 to $100 million. We also expect to generate $1 to $1.3 billion in cash flow from continuing operations.

In the remainder of 2004, we expect to make additional progress towards debt reduction while maintaining management's estimate of appropriate levels of cash and other forms of liquidity. To manage our operations and meet unforeseen or extraordinary calls on cash, we expect to maintain liquidity levels of at least $1 billion. Through debt tenders, open market repurchases and scheduled maturities, we have reduced our debt to $9.8 billion at June 30, 2004, a reduction of over $2.2 billion for the year-to-date. Primarily through additional debt tenders, we expect to further reduce debt to a level of approximately $9 billion by the end of 2004. While our access to the capital markets continues to improve, one of our indentures, and our two unsecured revolving credit facilities, have covenants that restrict our ability to issue new debt, with minimal exceptions, until a certain fixed charge coverage ratio is achieved. We expect to satisfy this requirement by the end of 2005. Our secured revolving credit facility has a covenant restricting our ability to issue new debt if, after giving effect to the issuance, we were to fail to meet the associated consolidated debt to consolidated net worth ratio.