I.12-01-007, I.11-02-016, I.11-11-009.

PG&E'S REQUEST FOR OFFICIAL NOTICE

EXHIBIT 11

Kinder Morgan, Inc., Annual Report (Form 10-K) (Mar. 1, 2007)

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

FORM 10-K

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

For the fiscal year ended **December 31, 2006**
or

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

For the transition period from _____to_____

Commission File Number 1-06446

Kinder Morgan, Inc.

(Exact name of registrant as specified in its charter)

Kansas	48-0290000
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

500 Dallas Street, Suite 1000, Houston, Texas 77002
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code (713) 369-9000

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common stock, par value $5 per share	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act:

Preferred stock, Class A $5 cumulative series
(Title of class)

Indicate by checkmark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:
Yes ☑ No ☐

Indicate by checkmark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:
Yes ☐ No ☑

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant was $10,705,381,712 at June 30, 2006.

The number of shares outstanding of the registrant's common stock, $5 par value, as of January 31, 2007 was 134,188,793 shares.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONTENTS

KINDER MORGAN, INC. AND SUBSIDIARIES
CONTENTS (Continued)

Note: Individual financial statements of the parent company are omitted pursuant to the provisions of Accounting Series Release No. 302.

PART I

Items 1. and 2. *Business and Properties.*

In this report, unless the context requires otherwise, references to "we," "us," "our," or the "Company" are intended to mean Kinder Morgan, Inc. (a Kansas corporation, incorporated on May 18, 1927, formerly known as K N Energy, Inc.) and its consolidated subsidiaries. All dollars are United States dollars, except where stated otherwise. Canadian dollars are designated as C$. To convert December 31, 2006 balances denominated in Canadian dollars to U.S. dollars, we used the December 31, 2006 Bank of Canada closing exchange rate of 0.8581 U.S. dollars per Canadian dollar. Unless otherwise indicated, all volumes of natural gas are stated at a pressure base of 14.73 pounds per square inch absolute and at 60 degrees Fahrenheit and, in most instances, are rounded to the nearest major multiple. In this report, the term "MMcf" means million cubic feet, the term "Bcf" means billion cubic feet, the term "TJ" means terajoule (one thousand gigajoules), the term "PJ" means petajoule (one million gigajoules), the term "bpd" means barrels per day and the terms "Dth" (dekatherms) and "MMBtus" mean million British Thermal Units ("Btus"). Natural gas liquids consist of ethane, propane, butane, iso-butane and natural gasoline. For the purpose of making Imperial to Metric conversions, 1 mile equals 1.609 kilometers and 1MMBtu equals 1.055 gigajoules. The following discussion should be read in conjunction with the accompanying Consolidated Financial Statements and related Notes.

(A) General Development of Business

We are one of the largest energy transportation and storage companies in North America. We own the general partner interest and a significant limited partner interest in Kinder Morgan Energy Partners, L.P. ("Kinder Morgan Energy Partners"), a publicly traded pipeline limited partnership. Due to our implementation of Emerging Issues Task Force ("EITF") No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*, we have included Kinder Morgan Energy Partners and its consolidated subsidiaries in our consolidated financial statements effective January 1, 2006. This means that the accounts, balances and results of operations of Kinder Morgan Energy Partners and its consolidated subsidiaries are now presented on a consolidated basis with ours and those of our other consolidated subsidiaries for financial reporting purposes, instead of equity method accounting as previously reported. See Note 1(B) of the accompanying Notes to Consolidated Financial Statements. We operate or own an interest in approximately 43,000 miles of pipelines and approximately 155 terminals. Our pipelines transport more than two million barrels per day of gasoline and other petroleum products and up to 10.5 billion cubic feet per day of natural gas. Our terminals handle over 80 million tons of coal and other dry-bulk materials annually and have a liquids storage capacity of almost 70 million barrels for petroleum products and chemicals. We own and operate retail natural gas distribution businesses serving approximately 905,000 customers in British Columbia. We are also the leading independent provider of carbon dioxide for enhanced oil recovery projects in the United States. Our common stock is traded on the New York Stock Exchange under the symbol "KMI." Our executive offices are located at 500 Dallas Street, Suite 1000, Houston, Texas 77002 and our telephone number is (713) 369-9000.

On October 7, 1999, we completed the acquisition of Kinder Morgan (Delaware), Inc., a Delaware corporation and the sole stockholder of the general partner of Kinder Morgan Energy Partners. To effect that acquisition, we issued approximately 41.5 million shares of our common stock in exchange for all of the outstanding shares of Kinder Morgan (Delaware). Upon closing of the transaction, Richard D. Kinder, Chairman and Chief Executive Officer of Kinder Morgan (Delaware), was named our Chairman and Chief Executive Officer, and we were renamed Kinder Morgan, Inc. As a result of that acquisition and certain subsequent transactions, we own the general partner of, and have a significant limited partner interest in, Kinder Morgan Energy Partners, one of the largest publicly traded pipeline limited partnerships in the United States in terms of market capitalization, and the owner and operator of the largest independent refined petroleum products pipeline system in the United States in terms of volumes delivered. Additional information concerning our investment in Kinder Morgan Energy Partners and its various businesses is contained in Note 2 of the accompanying Notes to Consolidated Financial Statements and in Kinder Morgan Energy Partners' 2006 Annual Report on Form 10-K.

In May 2001, Kinder Morgan Management, LLC ("Kinder Morgan Management"), one of our indirect subsidiaries, issued and sold its limited liability shares in an underwritten initial public offering. The net proceeds from the offering were used by Kinder Morgan Management to buy i-units from Kinder Morgan Energy Partners for $991.9 million. Upon purchase of the i-units, Kinder Morgan Management became a limited partner in Kinder Morgan Energy Partners and was delegated by Kinder Morgan Energy Partners' general partner, the responsibility to manage and control the business and affairs of Kinder Morgan Energy Partners. The i-units are a class of Kinder Morgan Energy Partners' limited partner interests that have been, and will be, issued only to Kinder Morgan Management. We have certain rights and obligations with respect to these securities.

In the initial public offering, we purchased 10% of the Kinder Morgan Management shares, with the balance purchased by the public. The equity interest in Kinder Morgan Management (which is consolidated in our financial statements) owned by the public is reflected as minority interest on our balance sheet. The earnings recorded by Kinder Morgan Management that are attributed to its shares held by the public are reported as "minority interest" in our Consolidated Statements of Operations. Subsequent to the initial public offering by Kinder Morgan Management of its shares, our ownership interest in Kinder Morgan Management has changed because (i) we recognize our share of Kinder Morgan Management's earnings, (ii) we record the receipt of distributions attributable to the Kinder Morgan Management shares that we own, (iii) Kinder Morgan Management has made additional sales of its shares (both through public and private offerings), (iv) pursuant to an option feature that was previously available to Kinder Morgan Management shareholders but no longer exists, we exchanged certain of the Kinder Morgan Energy Partners' common units held by us for Kinder Morgan Management shares held by the public and (v) we sold some Kinder Morgan Management shares we owned in order to generate taxable gains to offset expiring tax loss carryforwards. At December 31, 2006, we owned 10.3 million Kinder Morgan Management shares representing 16.5% of Kinder Morgan Management's total outstanding shares. Additional information concerning the business of, and our investment in and obligations to, Kinder Morgan Management is contained in Note 3 of the accompanying Notes to Consolidated Financial Statements and in Kinder Morgan Management's 2006 Annual Report on Form 10-K.

On November 30, 2005, we completed the acquisition of Terasen Inc., referred to in this report as Terasen and, accordingly, Terasen's results of operations are included in our consolidated results of operations beginning on that date. Terasen is an energy transportation and utility services provider headquartered in Burnaby, British Columbia, Canada. Terasen's two core businesses are its natural gas distribution business and its petroleum pipeline business. Terasen Gas is the largest distributor of natural gas in British Columbia, serving approximately 905,000 customers at December 31, 2006. Terasen Pipelines, which we have renamed Kinder Morgan Canada, operates Trans Mountain Pipe Line, which extends from Edmonton to Vancouver and Washington State, and Corridor Pipeline, which operates between the Alberta oilsands and Edmonton. Both Trans Mountain Pipe Line and Corridor Pipeline are owned by Terasen. Kinder Morgan Canada also operates, and Terasen owns a one-third interest in, the Express System, which extends from Alberta to the U.S. Rocky Mountain region and Midwest.

On May 29, 2006, we announced that our board of directors had received a proposal from investors led by Richard D. Kinder, our Chairman and Chief Executive Officer, to acquire all of our outstanding common stock for $100 per share in cash. The investors include Richard D. Kinder, other senior members of our management, co-founder Bill Morgan, current board members Fayez Sarofim and Mike Morgan, and affiliates of Goldman Sachs Capital Partners, American International Group, Inc., The Carlyle Group, and Riverstone Holdings LLC. Our board of directors formed a special committee composed entirely of independent directors to consider the proposal. On August 28, 2006, we entered into a definitive merger agreement under which the investors would acquire all of our outstanding common stock (except for shares held by certain stockholders and investors) for $107.50 per share in cash, without interest, and our board of directors, on the unanimous recommendation of the special committee, approved the agreement and recommended that our stockholders approve the merger.

Our stockholders voted to approve the proposed merger agreement on December 19, 2006. On January 25, 2007, we announced that we had received Hart-Scott-Rodino Antitrust Improvements Act clearance for the proposed acquisition. The Federal Trade Commission had challenged the participation of certain investors, but those investors reached a settlement with the FTC that clears the way for the acquisition to proceed. Currently, the only outstanding approvals are from certain state regulatory utility commissions. The California Public Utilities Commission issued a procedural schedule which could delay the closing of the transaction until the second quarter of 2007; however, we are working diligently with the CPUC to try to expedite the matter and are hopeful that the transaction can be closed in the first or second quarter of 2007. Upon closing of the transaction, our common stock will no longer be traded on the New York Stock Exchange.

Business Strategy

Our business strategy is to: (i) focus on fee-based energy transportation and storage assets that are core to the energy infrastructure of growing markets within North America, (ii) increase utilization of our existing assets while controlling costs, operating safely and employing environmentally sound operating practices, (iii) leverage economies of scale from incremental acquisitions and expansions of properties that fit within our strategy and are accretive to earnings and cash flow and (iv) maximize the benefits of our financial structure to create and return value to our stockholders as discussed following.

We intend to maintain a capital structure that provides flexibility and stability, while returning value to our shareholders through dividends and share repurchases. During 2006, we utilized cash generated from operations (including cash received from distributions attributable to our investment in Kinder Morgan Energy Partners) to pay common stock dividends, finance our capital expenditures program and repurchase our common shares. In recent periods, we have increased our common stock dividends in response to changes in income tax laws that have made dividends a more efficient way to return cash to our shareholders.

We expect to benefit from accretive acquisitions (primarily by Kinder Morgan Energy Partners). Kinder Morgan Energy Partners has a multi-year history of making accretive acquisitions, which benefit us through our limited and general partner interests. This acquisition strategy is expected to continue, although we can provide no assurance that such acquisitions will occur in the future. In addition, we expect to benefit from expansion opportunities pursued both by Kinder Morgan Energy Partners and by us. Along with Sempra Pipelines & Storage, a unit of Sempra Energy, and ConocoPhillips, Kinder Morgan Energy Partners is developing the Rockies Express Pipeline, a new natural gas pipeline that when completed will link producing areas in the Rocky Mountain region to the upper Midwest and Eastern United States. The approximately $4.4 billion project will be placed in service in segments and is expected to be completed by June 2009, subject to regulatory approvals. The Rockies Express Pipeline will have the capability to transport 1.8 Bcf per day of natural gas, and binding firm commitments have been secured for virtually all of the pipeline capacity. We expect to expand, within strict guidelines as to risk, rate of return and timing of cash flows, Kinder Morgan Canada's (formerly Terasen Pipelines') pipeline systems and NGPL's pipeline system.

We regularly consider and enter into discussions regarding potential acquisitions and are currently contemplating potential acquisitions. Any such transaction would be subject to negotiation of mutually agreeable terms and conditions, receipt of fairness opinions and approval of the respective boards of directors. While there are currently no unannounced purchase agreements for the acquisition of any material business or assets, such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations.

It is our intention to carry out the above business strategy, modified as necessary to reflect changing economic conditions and other circumstances. However, as discussed under "Risk Factors" elsewhere in this report, there are factors that could affect our ability to carry out our strategy or affect its level of success even if carried out.

Recent Developments

- **Going Private Transaction**
  As discussed above, on December 19, 2006, our stockholders voted to approve a definitive merger agreement under which investors led by Richard D. Kinder, our Chairman and Chief Executive Officer, would acquire all of our outstanding common stock for $107.50 per share in cash. The transaction is expected to be completed in the first or second quarter of 2007, subject to receipt of regulatory approvals, as well as the satisfaction of other customary closing conditions.

- **Sale of U.S. Retail Operations**
  In August 2006, we entered into a definitive agreement with a subsidiary of General Electric Company to sell our U.S. retail natural gas distribution and related operations for $710 million plus working capital. Pending regulatory approvals, we expect this transaction to close by the end of the first quarter of 2007. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* the financial results of these operations have been reclassified to discontinued operations for all periods presented.

- **Sale of Terasen Gas Business Segment**
  On February 26, 2007, we entered into a definitive agreement to sell Terasen Inc. to Fortis Inc. (TSX: FTS), a Canada-based company with investments in regulated distribution utilities, for approximately $3.2 billion (C$3.7 billion) including cash and assumed debt. Terasen Inc.'s principal assets include Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. The transaction is subject to certain closing conditions and regulatory approvals and is expected to close in mid 2007. This sale does not include assets of Kinder Morgan Canada.

- **Dividends**
  We increased our annual rate of cash dividends per share by $0.50 in the first quarter of 2006, reaching an annual rate of $3.50. This increase was principally in response to federal tax legislation enacted in 2003 and to increased cash flow.

- **NGPL Re-Contracting Transportation and Storage Capacity**
  In 2006, NGPL extended long-term firm transportation and storage contracts with some of its largest shippers, including Northern Illinois Gas Company (Nicor), The Peoples Gas Light and Coke Company, Centerpoint Energy Minnesota Gas, Interstate Power and Light Company, subsidiaries of Ameren Corporation, and Wisconsin Electric Power Co. Combined, the contracts represent approximately 0.49 million Dth per day of annual firm transportation service.

- **NGPL Storage Expansions**
  In the second quarter of 2006, NGPL placed into service a $38 million expansion of its Sayre storage field located in Oklahoma, which added 10 Bcf of storage service capacity, all of which is contracted for under long-term agreements. In August 2005, NGPL filed a certificate application with the Federal Energy Regulatory Commission ("FERC") for an additional 10 Bcf expansion of its North Lansing storage facility located in east Texas, at a cost of $74 million. All of the capacity is contracted for under long-term agreements. The FERC order approving the project

was issued January 23, 2006. Service is anticipated to commence during the spring of 2007.

- **NGPL Amarillo-Gulf Coast Line Expansion**
  In the second quarter of 2006, NGPL placed into service its Amarillo-Gulf Coast cross-haul expansion. The $21 million project added 51,000 Dth per day of capacity and is fully subscribed under long-term contracts. In addition, NGPL added a new compressor station to Segment 17 of its Amarillo-Gulf Coast line that provides 140 MMcf per day of additional capacity. The $17 million project was placed in service January 6, 2007, and all of the additional capacity is fully contracted.

- **NGPL Louisiana Line Expansion**
  In October 2006, NGPL filed with the FERC seeking approval to expand its Louisiana Line by 200,000 Dth per day. This $66 million project is supported by five-year agreements that fully subscribe the additional capacity.

- **Kinder Morgan Illinois Pipeline**
  In September 2006, Kinder Morgan Illinois Pipeline filed with FERC seeking approval to acquire lease capacity on NGPL and build facilities to supply service for The Peoples Gas Light and Coke Co., who has signed a 10-year agreement for all the capacity. The $13.3 million project would have a capacity of 360,000 Dth per day.

- **Terasen Gas Pipeline Project**
  In June 2006, the BCUC approved an application from Terasen Gas Inc. to build a 50-kilometer natural gas pipeline from Squamish to Whistler. The estimated C$42 million project, which includes the cost of retrofitting utility customers' gas-fired appliances from propane to natural gas use, will replace an aging propane system. Construction on this project is being integrated with and performed by the contractor performing the highway upgrades to Whistler in advance of the 2010 Winter Olympics. We expect full service to be available to Whistler by November 2008.

- **Kinder Morgan Canada Trans Mountain Pipeline Expansions**
  On November 10, 2005, Kinder Morgan Canada received approval from the National Energy Board ("NEB") to increase the capacity of the Trans Mountain pipeline system from 225,000 barrels per day ("bpd") to 260,000 bpd. The C$195 million expansion is designed to add 35,000 bpd of heavy crude oil capacity by building new and upgrading existing pump stations along the pipeline system between Edmonton, Alberta, and Burnaby, British Columbia. Construction began in the summer of 2006 and the expansion is expected to be in service by April 2007.

  Kinder Morgan Canada filed a comprehensive environmental report with the Canadian Environmental Assessment Agency on November 15, 2005, and filed a complete NEB application for the Anchor Loop Project on February 17, 2006. The C$443 million project involves looping a 98-mile section of the existing Trans Mountain pipeline system between Hinton, Alberta, and Jackman, British Columbia, and the addition of three new pump stations. With construction of the Anchor Loop, the Trans Mountain system's capacity will increase from 260,000 bpd to 300,000 bpd by the end of 2008. The public hearing of the application was held the week of August 8, 2006. On October 26, 2006, the NEB released its favorable decision on the application.

- **Kinder Morgan Canada Corridor Pipeline Expansion**
  An application for the Corridor pipeline expansion project was filed with the Alberta Energy Utilities Board and Alberta Environment on December 22, 2005, and approval was received in August 2006. The proposed C$1.8 billion expansion, as authorized and supported by shipper resolutions and the underlying firm service agreement, includes building a new 42-inch diameter diluent/bitumen ("dilbit") pipeline, a new 20-inch diameter products pipeline, tankage and upgrading existing pump stations along the existing pipeline system from the Muskeg River Mine north of Fort McMurray to the Edmonton region. The Corridor pipeline expansion would add an initial 180,000 bpd of dilbit capacity to accommodate the new bitumen production from the Muskeg River Mine. An expansion of the Corridor pipeline system has been completed in 2006 increasing the dilbit capacity to 278,000 bpd by upgrading existing pump station facilities. By 2009, the dilbit capacity of the Corridor system is expected to be approximately 460,000 bpd. Construction of the Corridor pipeline expansion began in November 2006.

- **Products Pipelines – KMP Pacific Operations Regulatory Matter**
  On March 7, 2006, Kinder Morgan Energy Partners' Pacific operations filed a revised cost of service filing with the FERC in accordance with the FERC's December 16, 2005 order addressing two cases: (i) the phase two initial decision, issued September 9, 2004, which would establish the basis for prospective rates and the calculation of reparations for complaining shippers with respect to the Pacific operations' West Line and East Line pipelines, and (ii) certain cost of service issues remanded to the FERC by the United States Court of Appeals for the District of Columbia Circuit, referred to in this report as D.C. Circuit, in its July 2004 *BP West Coast Products v. FERC* opinion, including the level of income tax allowance that the Pacific operations is entitled to include in its interstate rates. The December 16, 2005 order did not address the FERC's March 2004 phase one rulings on the grandfathered

state of the Pacific operations' rates that are currently pending on appeal before the D.C. Circuit.

On April 28, 2006, the FERC issued an order accepting Kinder Morgan Energy Partners' Pacific operations' compliance filing and revised tariffs, which lowered its West Line and East Line rates in conformity with previous FERC orders, and these lower tariff rates became effective May 1, 2006. Further, Kinder Morgan Energy Partners was required to calculate estimated reparations for complaining shippers consistent with the December 16, 2005 FERC order, and various parties have submitted comments to the FERC challenging aspects of the costs of service and tariff rates reflected in the compliance filings. The FERC indicated that a subsequent order would address the issues raised in these comments. In December 2005, Kinder Morgan Energy Partners recognized a $105.0 million non-cash expense attributable to an increase in its reserves related to its rate case liability; however, we are not able to predict with certainty the final outcome of the pending FERC proceedings, or whether we can reach a settlement with some or all of the complainants. For additional information, see Note 19 to our consolidated financial statements.

- **Products Pipelines – KMP Watson Station Regulatory Settlement**
  On May 17, 2006, Kinder Morgan Energy Partners entered into a settlement agreement and filed an offer of settlement with the FERC in response to certain challenges by complainants with regard to delivery tariffs and gathering enhancement fees at the Pacific operations' Watson Station, located in Carson, California. On August 2, 2006, the FERC approved the settlement without modification and directed that it be implemented. Pursuant to the settlement, Kinder Morgan Energy Partners filed a new tariff, which took effect September 1, 2006, lowering the Pacific Operations' going-forward rate, and Kinder Morgan Energy Partners also paid refunds to all shippers for the period April 1, 1999 through August 31, 2006.

  On September 28, 2006, Kinder Morgan Energy Partners filed a refund report with the FERC, setting forth the refunds that had been paid and describing how the refund calculations were made. On December 5, 2006, the FERC approved the refund report with respect to all shippers except ExxonMobil, and it remanded the ExxonMobil refund issue to an administrative law judge for a determination as to whether additional refunds were due. On January 16, 2007, Kinder Morgan Energy Partners and ExxonMobil informed the presiding judge that they had reached a settlement in principle regarding the ExxonMobil refund issue, and in February 2007, Kinder Morgan Energy Partners and ExxonMobil reached agreement regarding ExxonMobil's protest of the refund report, and the protest was withdrawn. As of December 31, 2006, Kinder Morgan Energy Partners made aggregate payments pursuant to the agreement, including accrued interest, of $19.1 million.

- **Products Pipelines – KMP Pacific Operations East Line Expansion**
  On June 1, 2006, Kinder Morgan Energy Partners announced that it had completed and fully placed into service a $210 million expansion of the Pacific operations' East Line pipeline segment. The completion of the project included the construction of a new pump station, a 490,000 barrel tank facility near El Paso, Texas, and upgrades to existing stations and terminals between El Paso and Phoenix, Arizona. Initially proposed in October 2002, the expansion also includes the replacement of 160 miles of 8-inch diameter pipe between El Paso and Tucson, Arizona, and 84 miles of 8-inch diameter pipe between Tucson and Phoenix with new state-of-the-art 12-inch and 16-inch diameter pipe, respectively. Kinder Morgan Energy Partners announced the completion of the pipeline portion of the project on April 19, 2006, and new transportation tariffs designed to earn a return on its construction costs went into effect June 1, 2006.

  In addition, Kinder Morgan Energy Partners continues working on its second East Line expansion project, which it announced on August 4, 2005. This second expansion consists of replacing approximately 140 miles of 12-inch diameter pipe between El Paso and Tucson with 16-inch diameter pipe, constructing additional pump stations, and adding new storage tanks at Tucson. The project is expected to cost approximately $145 million. Kinder Morgan Energy Partners is currently working on engineering design and obtaining necessary pipeline permits, and construction is expected to begin in May 2007. The project, scheduled for completion in December 2007, will increase East Line capacity by another 8% and will provide the platform for further incremental expansions through horsepower additions to the system.

- **Products Pipelines – KMP CALNEV Pipeline System Expansion**
  On October 19, 2006, Kinder Morgan Energy Partners announced the third of three investments in its CALNEV refined petroleum products pipeline system. CALNEV is a 550-mile pipeline that currently transports approximately 140,000 barrels of refined products per day of gasoline, diesel fuel and jet fuel from the Los Angeles, California area to the Las Vegas, Nevada market through parallel 14-inch and 8-inch diameter pipelines. Combined, the $413 million in capital improvements will upgrade and expand pipeline capacity and help provide sufficient fuel supply to the Las Vegas, Nevada market for the next several years. The investments include the following:

  - the first project, estimated to cost approximately $10 million, involves pipeline expansions that will increase current transportation capacity by 3,200 barrels per day (2.2%), as well as the construction of two new 80,000 barrel storage tanks at the Las Vegas terminal;

- the second project, expected to cost approximately $15 million, includes the installation of new and upgraded pumping equipment and piping at the Colton, California terminal, a new booster station with two pumps at Cajon, California, and piping upgrades at the Las Vegas terminal; and

- the third project, expected to cost approximately $388 million, includes construction of a new 16-inch diameter pipeline that will further expand the system and which would increase system capacity to approximately 200,000 barrels per day upon completion. Capacity could be increased as necessary to over 300,000 barrels per day with the addition of pump stations. The new 16-inch diameter pipeline will parallel existing utility corridors between Colton and Las Vegas in order to minimize environmental impacts. It will transport gasoline and diesel, as well as military jet fuel for Nellis Air Force Base, which is located eight miles northeast of downtown Las Vegas. The existing 14-inch diameter pipeline will be dedicated to commercial jet fuel service for McCarran International Airport in Las Vegas and for any future commercial airports planned for the Las Vegas market. The 8-inch diameter pipeline that currently serves McCarran would be purged and held for future service. The expansion is subject to environmental permitting, rights-of-way acquisition and the receipt of approvals from the FERC authorizing rates that are economic to CALNEV. Start-up of the new pipeline is scheduled for early 2010.

  In addition, Kinder Morgan Energy Partners is currently working with its customers to determine interest in the construction of a new refined products distribution terminal to be located south of Henderson, Nevada.

- **Products Pipelines – KMP Cochin Pipeline System Ownership Interest To Increase to 100%**
  On January 15, 2007, Kinder Morgan Energy Partners announced that it had entered into an agreement with affiliates of BP to increase Kinder Morgan Energy Partners' ownership interest in the Cochin pipeline system to 100%. Kinder Morgan Energy Partners purchased its original undivided 32.5% ownership interest in the Cochin pipeline system in November 2000, and currently, Kinder Morgan Energy Partners owns a 49.8% ownership interest. BP Canada Energy Company, an affiliate of BP, owns the remaining 50.2% ownership interest and is the operator of the pipeline. The agreement is subject to due diligence, regulatory clearance and other customary closing conditions. The transaction is expected to close in the first quarter of 2007, and upon closing, Kinder Morgan Energy Partners will become the operator of the pipeline.

- **Natural Gas Pipelines – KMP Rockies Express Pipeline**
  Effective February 23, 2006, Rockies Express Pipeline LLC acquired Entrega Gas Pipeline LLC from EnCana Corporation for $244.6 million in cash. West2East Pipeline LLC is a limited liability company and is the sole owner of Rockies Express Pipeline LLC. Kinder Morgan Energy Partners contributed 66 2/3% of the consideration for this purchase, which corresponded to its percentage ownership of West2East Pipeline LLC at that time. At the time of acquisition, Sempra Energy held the remaining 33 1/3% ownership interest and contributed this same proportional amount of the total consideration.

  On the acquisition date, Entegra Gas Pipeline LLC owned the Entrega Pipeline, an interstate natural gas pipeline that now consists of two segments: (i) a 136-mile, 36-inch diameter pipeline that extends from the Meeker Hub in Rio Blanco County, Colorado to the Wamsutter Hub in Sweetwater County, Wyoming and (ii) a 191-mile, 42-inch diameter pipeline that extends from the Wamsutter Hub to the Cheyenne Hub in Weld County, Colorado, where it will ultimately connect with the Rockies Express Pipeline, an interstate natural gas pipeline that is currently being developed by Rockies Express Pipeline LLC. In the first quarter of 2006, EnCana Corporation completed construction of the pipeline segment that extends from the Meeker Hub to the Wamsutter Hub, and interim service began on that portion of the pipeline on February 24, 2006. In February 2007, Kinder Morgan Energy Partners completed construction of the second pipeline segment that extends from the Wamsutter Hub to the Cheyenne Hub and service began on the first two pipeline segments on February 14, 2007.

  However, our operating revenues and our operating expenses were not impacted during the construction or interim service periods due to the fact that regulatory accounting provisions require capitalization of revenues and expenses until the second segment of the project was completed and in-service.

  In April 2006, Rockies Express Pipeline LLC merged with and into Entrega Gas Pipeline LLC, and the surviving entity was renamed Rockies Express Pipeline LLC. Going forward, the entire pipeline system (the two Entrega segments described above and the two Rockies Express segments that are currently being developed and described below) will be known as the Rockies Express Pipeline.

  On May 31, 2006, Rockies Express Pipeline LLC filed an application with the FERC for authorization to construct and operate certain facilities comprising its proposed Rockies Express-West project. This project is the first planned eastward extension of the certificated Rockies Express segments, described above. The Rockies Express-West project will be comprised of approximately 713 miles of 42-inch diameter pipeline extending from the Cheyenne Hub to an interconnection with Panhandle Eastern Pipe Line located in Audrain County, Missouri. The segment extension will have capacity to transport up to 1.5 billion cubic feet per day of natural gas across the following five states: Wyoming, Colorado, Nebraska, Kansas and Missouri. The project will also include certain improvements to existing Rockies Express facilities located to the west of the Cheyenne Hub.

On June 30, 2006, ConocoPhillips exercised its option to acquire a 25% ownership interest in West2East Pipeline LLC (and indirectly, its subsidiary Rockies Express Pipeline LLC). On that date, a 24% ownership interest was transferred to ConocoPhillips, and an additional 1% interest will be transferred once construction of the entire Rockies Express Pipeline project is completed. Through its subsidiary Kinder Morgan W2E Pipeline LLC, Kinder Morgan Energy Partners continues to operate the project but its equity ownership interest decreased from 66 2/3% to 51%. Sempra's ownership interest in West2East Pipeline LLC decreased to 25% (down from 33 1/3%). When construction of the entire project is completed, Kinder Morgan Energy Partners' ownership interest will be reduced to 50% at which time the capital accounts of West2East Pipeline LLC will be trued up to reflect Kinder Morgan Energy Partners' 50% economics in the project. We do not anticipate any additional changes in the ownership structure of the project.

On September 21, 2006, the FERC issued a favorable preliminary determination on all non-environmental issues of the Rockies Express-West project, approving Rockies Express' application (i) to construct and operate the 713 miles of new natural gas transmission facilities from the Cheyenne Hub and (ii) to lease capacity from Questar Overthrust Pipeline Company, which will extend the Rockies Express system 140 miles west from Wamsutter to the Opal Hub in Wyoming. Pending completion of the FERC environmental review and the issuance of a certificate, the Rockies Express-West project is expected to begin service in January 2008.

The final segment of the Rockies Express Pipeline consists of an approximate 635-mile pipeline segment that will extend from eastern Missouri to the Clarington Hub in eastern Ohio. Rockies Express will file a separate application in the future for this proposed Rockies Express-East project. In June 2006, Kinder Morgan Energy Partners made the National Environmental Policy Act pre-filing for Rockies Express-East with the FERC. This project is expected to begin interim service as early as December 31, 2008, and to be fully completed by June 2009. When fully completed, the combined 1,675-mile Rockies Express Pipeline system will be one of the largest natural gas pipelines ever constructed in North America. The approximately $4.4 billion project will have the capability to transport 1.8 billion cubic feet per day of natural gas, and binding firm commitments have been secured for virtually all of the pipeline capacity.

- **Natural Gas Pipelines – KMP Sale of Douglas Gathering System and Painter Unit Fractionation Facility**
  Effective April 1, 2006, Kinder Morgan Energy Partners sold its Douglas natural gas gathering system and its Painter Unit fractionation facility to Momentum Energy Group, LLC for approximately $42.5 million in cash. Our investment in net assets, including all transaction related accruals, was approximately $24.5 million, most of which represented property, plant and equipment, and we recognized approximately $18.0 million of gain on the sale of these net assets.

  Additionally, with regard to the natural gas operating activities of our Douglas gathering system, we utilized certain derivative financial contracts to offset (hedge) our exposure to fluctuating expected future cash flows caused by periodic changes in the price of natural gas and natural gas liquids. According to the provisions of current accounting principles, when an asset generating a hedged transaction is disposed of prior to the occurrence of the transaction, the net cumulative gain or loss previously recognized in equity should be transferred to net income in the current period. Accordingly, we reclassified a net loss of $2.9 million from "Accumulated other comprehensive loss" into net income on those derivative contracts that effectively hedged uncertain future cash flows associated with forecasted Douglas gathering transactions. We included the net amount of the gain, $15.1 million, within the caption "Other expense (income)" in our accompanying consolidated statement of income for the year ended December 31, 2006.

- **Natural Gas Pipelines – KMP Long-term Transportation and Storage Services Contract**
  On April 18, 2006, Kinder Morgan Energy Partners announced that its Texas intrastate natural gas pipeline group had entered into a long-term agreement with CenterPoint Energy Resources Corp. to provide the natural gas utility with firm transportation and storage services. Under the terms of the agreement, CenterPoint has contracted for one billion cubic feet per day of transportation capacity and 16 billion cubic feet of storage capacity, effective April 1, 2007. CenterPoint owns and operates the largest local natural gas distribution company in Houston, Texas, and the agreement helps ensure the Houston metropolitan area has access to reliable and diverse supplies of natural gas in order to meet the growing demand.

- **Natural Gas Pipelines – KMP North Dayton, Texas Storage Expansion**
  On June 8, 2006, Kinder Morgan Energy Partners announced an approximate $76 million expansion project that will significantly increase capacity at its North Dayton, Te xas natural gas storage facility. The project involves the development of a new underground cavern that will add an estimated 5.5 billion cubic feet of incremental working natural gas storage capacity. Currently, two existing storage caverns at the facility provide approximately 4.2 billion cubic feet of working gas capacity. The North Dayton natural gas storage facility is connected to Kinder Morgan Energy Partners' Texas Intrastate natural gas pipeline system, and the expansion will greatly enhance storage options for natural gas coming from new and growing supply areas located in East Texas and from liquefied natural gas along the Texas Gulf Coast. Project costs are now anticipated to range from $76 million to $82 million, and the additional capacity is expected to be available in mid-2009.

- **Natural Gas Pipelines – KMP TransColorado's "Blanco-Meeker Expansion Project"**
  On June 23, 2006, TransColorado Gas Transmission Company filed an application for authorization with the FERC to construct and operate certain facilities comprising its proposed "Blanco-Meeker Expansion Project." Upon implementation, this approximately $58 million project will facilitate the transportation of up to approximately 250 million cubic feet per day of natural gas northbound from the Blanco Hub area in San Juan County, New Mexico through TransColorado's existing interstate pipeline for delivery to the Rockies Express Pipeline at an existing point of interconnection located at the Meeker Hub in Rio Blanco County, Colorado. The expansion is expected to begin service on January 1, 2008, subject to receipt of all necessary regulatory approvals.

- **Natural Gas Pipelines – KMP Kinder Morgan Louisiana Pipeline**
  On September 8, 2006, Kinder Morgan Energy Partners filed an application with the FERC requesting approval to construct and operate the Kinder Morgan Louisiana Pipeline. The project is expected to cost approximately $500 million and will provide approximately 3.2 billion cubic feet per day of take-away natural gas capacity from the Cheniere Sabine Pass liquefied natural gas terminal located in Cameron Parish, Louisiana. The project is supported by fully subscribed capacity and long -term customer commitmen ts with Chevron and Total. Various water and environmental surveys have been completed and Kinder Morgan Energy Partners procured long-lead items, such as line pipe and mainline block valves. Kinder Morgan Energy Partners is currently finalizing interconnect agreements, preparing detailed designs of the facilities and acquiring necessary rights-of-way.

  The Kinder Morgan Louisiana Pipeline will consist of two segments: (i) a 132-mile, 42-inch diameter pipeline with firm capacity of approximately 2.0 billion cubic feet per day of natural gas that will extend from the Sabine Pass terminal to a point of interconnection with an existin g Columbia Gulf Transmission line in Evangeline Parish, Louisiana, including an offshoot consisting of approximately 2.3 miles of 24-inch diameter pipeline with firm peak day capacity of approximately 300 million cubic feet per day extending away from the 42-inch diameter line to the existing Florida Gas Transmission Company compressor station in Acadia Parish, Louisiana.; and (ii) a 1-mile, 36-inch diameter pipeline with firm capacity of approximately 1.2 billion cubic feet per day that will extend from the Sabine Pass terminal and connect to Natural Gas Pipeline Company of America's natural gas pipeline. In addition, in exchange for shipper commitments to the project, Kinder Morgan Energy Partners has granted options to acquire equity in the project, which, if fully exercised, could result in Kinder Morgan Energy Partners owning a minimum interest of 80% after the project is completed. The 132-mile pipeline segment is expected to be in service in the second quarter of 2009, and the 1-mile segment is expected to be in service in the third quarter of 2008.

  On January 26, 2007, the FERC issued a draft Environm ental Impact Statement ("EIS") which addresses the potential environmental effects of the construction and operation of the Kinder Morgan Louisiana Pipeline. The draft EIS was prepared to sa tisfy the requirements of the National Environmental Policy Act. It concluded that approval of the proposed project would have limited adverse environmental impact. The public will have until March 19, 2007 to file comments on the draft, which will be taken into account in the preparation of the final EIS.

- **Natural Gas Pipelines – KMP Midcontinent Express Pipeline**
  On December 13, 2006, Kinder Morgan Energy Partners announced that it had entered into a joint development of the Midcontinent Express Pipeline with Energy Transfer Partners, L.P., and the start of a binding open season for the pipeline's firm natural gas transportation capacity. The approximate $1.25 billion interstate natural gas pipeline project will consist of an approximate 500-mile pipeline that will originate near Bennington, Oklahoma, be routed through Perryville, Louisiana, and terminate at an interconnect with Williams' Transco natural gas pipeline system in Butler, Alabama. Kinder Morgan Energy Partners will own 50% of the equity in the project and Energy Transfer Partners, L.P. will own the remaining 50% interest. The new pipeline will also connect to Natural Gas Pipeline Company of America's natural gas pipeline and to Energy Transfer Partners' previously announced 135-mile, 36-inch diameter natural gas pipeline, which extends from the Barnett Shale natural gas producing area in North Texas to an interconnect with its 30-inch diameter Texoma Pipeline near Paris, Texas.

  The Midcontinent Express Pipeline will have an initial transportation capacity of 1.4 billion cubic feet per day of natural gas, and pending necessary regulatory approvals, is expected to be in service by February 2009. The pipeline has prearranged binding commitments from multiple shippers for approximately 850,000 cubic feet per day, including a binding commitment for 500,000 cubic feet per day from Chesapeake Energy Marketing, Inc., an affiliate of Chesapeake Energy Corporation. Additionally, in order to provide a seamless transportation path from various locations in Oklahoma, the Midcontinent Express Pipeline has also executed a firm capacity lease agreement for up to 500,000 cubic feet per day with Enogex, Inc., an Oklahoma-based intrastate natural gas gathering and pipeline company that is wholly owned by OGE Energy Corp.

- **CO_2 – KMP Oil and Gas Property Acquisition**
  On April 5, 2006, Kinder Morgan Production Company L.P. purchased various oil and gas properties from Journey Acquisition – I, L.P. and Journey 2000, L.P. for an aggregate consideration of approximately $63.9 million, consisting of $60.3 million in cash and $3.6 million in assumed liabilities. The acquisition was effective March 1, 2006. However, in the second and third quarters of 2006, Kinder Morgan Energy Partners divested certain acquired properties that were not considered candidates for carbon dioxide enhanced oil recovery, thus reducing its total investment. Kinder Morgan Energy Partners received proceeds of approximately $27.1 million from the sale of these properties. The acquired properties are primarily located in the Permian Basin area of West Texas and New Mexico, produce approximately 430 barrels of oil equivalent per day, and include some fields with potential for enhanced oil recovery development near Kinder Morgan Energy Partners' current carbon dioxide operations.

- **CO_2 – KMP Carbon Dioxide Expansion Projects**
  On January 17, 2007, Kinder Morgan Energy Partners announced that its CO_2 business segment will invest approximately $120 million to further expand its operations and enable it to meet the increased demand for carbon dioxide in the Permian Basin. The expansion activities will take place in southwest Colorado and will include developing a new carbon dioxide source field and adding infrastructure at both the McElmo Dome Unit and the Cortez Pipeline. Specifically, the expansion will involve developing a new carbon dioxide source field in Dolores County, Colorado (named the Doe Canyon Deep Unit), adding eight carbon dioxide production wells at the McElmo Dome Unit, increasing transportation capacity on the Cortez Pipeline, and constructing a new pipeline that will connect the Cortez Pipeline to the new Doe Canyon Deep Unit. Initial construction activities have begun with expected in-service dates commencing in early 2008. The entire expansion is expected to be completed by the middle of 2008.

- **Terminals – KMP East Coast Liquids Terminal Expansion**
  On January 12, 2006, Kinder Morgan Energy Partners announced a major expansion project that will provide additional infrastructure to help meet the growing need for terminal services in key markets along the East Coast. The investment of approximately $45 million includes the construction of new liquids storage tanks at Kinder Morgan Energy Partners' Perth Amboy, New Jersey liquids terminal located along the Arthur Kill River in the New York Harbor area. The Perth Amboy expansion involves the construction of nine new storage tanks with a capacity of 1.4 million barrels for gasoline, diesel and jet fuel. The expansion was driven by continued strong demand for refined products in the Northeast, much of which is being met by imported fuel arriving via the New York Harbor. The new tanks were expected to be in service beginning in the first quarter of 2007, however, due to inconsistencies in the soils underneath these tanks, we now estimate that the tank foundations will cost significantly more than originally budgeted, bringing the total investment to approximately $56 million and delaying the in-service date to the third quarter of 2007.

- **Terminals – KMP Bulk Terminal Expansion**
  On March 9, 2006, Kinder Morgan Energy Partners announced that it has entered into a long-term agreement with Drummond Coal Sales, Inc. that will support a $70 million expansion of Kinder Morgan Energy Partners' Pier IX bulk terminal located in Newport News, Virginia. The agreement has a term that can be extended for up to 30 years. The project includes the construction of a new ship dock and the installation of additional equipment; it is expected to increase throughput at the terminal by approximately 30% and will allow the terminal to begin receiving shipments of imported coal. The expansion is expected to be completed in the first quarter of 2008. Upon completion, the terminal will have an import capacity of up to 9 million tons annually. Currently, the Pier IX terminal can store approximately 1.4 million tons of coal and 30,000 tons of cement on its 30-acre storage site.

- **Terminals – KMP Terminal Acquisition**
  In April 2006, Kinder Morgan Energy Partners acquired terminal assets and operations from A&L Trucking, L.P. and U.S. Development Group in three separate transactions for an aggregate consideration of approximately $61.9 million, consisting of $61.6 million in cash and $0.3 million in assumed liabilities. The first transaction included the acquisition of equipment and infrastructure for the storing and loading of bulk steel at a 30-acre site along the Houston Ship Channel leased through the Port of Houston. The second acquisition included the purchase of a rail terminal at the Port of Houston that handles both bulk and liquids products. The rail terminal offers a variety of loading, storage and staging services for up to 900 cars at a time, and complements Kinder Morgan Energy Partners'

existing Texas petroleum coke terminal operations by providing bulk product customers with rail transportation options. Thirdly, Kinder Morgan Energy Partners acquired the entire membership interest of Lomita Rail Terminal LLC, a limited liability company that owns a high-volume rail ethanol terminal in Carson, California. The terminal has the capability to receive and offload up to 100 railcars within a 24-hour period, and serves approximately 80% of the Southern California demand for reformulated fuel blend ethanol with expandable offloading/distribution capacity.

- **Terminals – KMP Construction of Crude Oil Tank Farm in Edmonton, Alberta**
  On June 21, 2006, Kinder Morgan Energy Partners announced that it, through its Kinder Morgan Terminals Canada, ULC subsidiary, began construction on a new $115 million crude oil tank farm located in Edmonton, Alberta, Canada, located slightly north of Kinder Morgan Canada's Trans Mountain Pipeline crude oil storage facility. In addition, Kinder Morgan Energy Partners entered into long-term contracts with customers for all of the available capacity at the facility, with options to extend the agreements beyond the original terms. Situated on approximately 24 acres, the new storage facility will have nine tanks with a combined storage capacity of approximately 2.2 million barrels for crude oil. Service is expected to begin in the fourth quarter of 2007, and when completed, the tank farm will serve as a premier blending and storage hub for Canadian crude oil. The tank farm will have access to more than 20 incoming pipelines and several major outbound systems, including a connection with Kinder Morgan Canada's 710-mile Trans Mountain Pipeline system, which currently transports up to 225,000 barrels per day of heavy crude oil and refined products from Edmonton to marketing terminals and refineries located in the greater Vancouver, British Columbia area and Puget Sound in Washington State.

- **Terminals – KMP Pasadena and Galena Park, Texas Liquids Terminal Expansions**
  On September 11, 2006, Kinder Morgan Energy Partners announced major expansions at its Pasadena and Galena Park, Texas liquids terminal facilities located on the Houston Ship Channel. The expansions will provide additional infrastructure to help meet the growing need for refined petroleum products storage capacity along the Gulf Coast. The investment of approximately $195 million will include the construction of the following: (i) new storage tanks at both the Pasadena and Galena Park terminals; (ii) an additional cross-channel pipeline to increase the connectivity between the two terminals; (iii) a new ship dock at Galena Park; and (iv) an additional loading bay at the fully automated truck loading rack located at the Pasadena terminal. The expansions are supported by long-term customer commitments and will result in approximately 3.4 million barrels of additional tank storage capacity at the two terminals. Construction began in October 2006 and all of the projects are expected to be completed by the spring of 2008.

- **Terminals – KMP Transload Services, LLC Acquisition**
  Effective November 20, 2006, Kinder Morgan Energy Partners acquired all of the membership interests of Transload Services, LLC for an aggregate consideration of approximately $16.8 million, consisting of $15.4 million in cash, an obligation to pay $0.9 million currently held as security for the collection of certain accounts receivable and for the perfection of certain real property title rights, and $0.5 million of assumed liabilities. Transload Services, LLC is a leading provider of innovative, high quality material handling and steel processing services, operating 14 steel-related terminal facilities located in the Chicago metropolitan area and various cities in the United States. Its operations include transloading services, steel fabricating and processing, warehousing and distribution, and project staging. The combined operations include over 92 acres of outside storage and 445,000 square feet of covered storage that offers customers environmentally controlled warehouses with indoor rail and truck loading facilities for handling temperature and humidity sensitive products.

- **Terminals – KMP Devco USA L.L.C. Acquisition**
  Effective December 1, 2006, Kinder Morgan Energy Partners acquired all of the membership interests in Devco USA L.L.C. for an aggregate consideration of approximately $7.3 million, consisting of $4.8 million in cash, $1.6 million in common units, and $0.9 million of assumed liabilities. The primary asset acquired was a technology-based identifiable intangible asset—a proprietary process that transforms molten sulfur into premium solid formed pellets that are environmentally friendly, easy to handle and store, and safe to transport. The process was developed internally by Devco's engineers and employees. Devco, a Tulsa, Oklahoma-based company, has more than 20 years of sulfur handling expertise and we believe the acquisition and subsequent application of this acquired technology complements Kinder Morgan Energy Partners' existing dry-bulk terminal operations.

- **Kinder Morgan Energy Partners Public Offering**
  In August 2006, Kinder Morgan Energy Partners completed a public offering of 5,750,000 of its common units, including common units sold pursuant to the underwriters' over-allotment option, at a price of $44.80 per unit, less commissions and underwriting expenses. Kinder Morgan Energy Partners received net proceeds of $248.0 million for the issuance of these 5,750,000 common units, and used the proceeds to reduce the borrowings under its commercial paper program.

- **Kinder Morgan Energy Partners Credit Facility Changes**
  Effective August 28, 2006, Kinder Morgan Energy Partners terminated its $250 million unsecured nine-month credit facility due November 21, 2006, and increased its five-year unsecured revolving credit facility from a total commitment of $1.6 billion to $1.85 billion. The five-year credit facility remains due August 18, 2010; however, the facility can now be amended to allow for borrowings up to $2.1 billion. There were no borrowings under the five-year credit facility as of December 31, 2006. The credit facility primarily serves as a backup to Kinder Morgan Energy Partners' commercial paper program, which had $1,098.2 million outstanding as of December 31, 2006.

- **Kinder Morgan Energy Partners Cash Distribution Expectations for 2007**
  On December 14, 2006, Kinder Morgan Energy Partners announced that it expects to declare cash distributions of $3.44 per unit for 2007, an almost 6% increase over cash distributions of $3.26 per unit for 2006. This expectation includes contributions from assets owned by Kinder Morgan Energy Partners as of the announcement date and does not include any potential benefits from unidentified acquisitions. We expect Kinder Morgan Energy Partners' growth to accelerate in the second half of 2007, and we anticipate that Kinder Morgan Energy Partners' fourth quarter 2007 distribution per unit will be approximately 10% higher than its cash distribution per unit of $0.83 for the fourth quarter of 2006. Furthermore, while we expect that we will continue to be able to grow Kinder Morgan Energy Partners' distribution per unit at about 8% per year over the long-term, the increase in 2008 is expected to be greater than 8%, due mainly to the anticipated in-service date of January 2008 for the western portion of the Rockies Express Pipeline.

- **Kinder Morgan Energy Partners 2006 Capital Expenditures**
  During 2006, Kinder Morgan Energy Partners spent $1,058.3 million for additions to property, plant and equipment, including both expansion and maintenance projects. Capital expenditures included the following:

  - $307.7 million in the Terminals – KMP segment, largely related to expanding the petroleum products storage capacity at liquids terminal facilities, including the construction of additional liquids storage tanks at facilities on the Houston Ship Channel, and to various expansion projects and improvements undertaken at multiple bulk terminal facilities;

  - $283.0 million in the CO2 – KMP segment, mostly related to additional infrastructure, including wells and injection and compression facilities, to support the expanding carbon dioxide flooding operations at the SACROC and Yates oil field units in West Texas;

  - $271.6 million in the Natural Gas Pipelines – KMP segment, mostly related to the inclusion of the capital expenditures of Rockies Express Pipeline LLC during the six-month period we included its results in our consolidated financial statements, as well as various expansion and improvement projects on the Texas Intrastate natural gas pipeline systems, including the development of additional natural gas storage capacity at the natural gas storage facilities located at Markham and Dayton, Texas; and

  - $196.0 million in the Products Pipelines – KMP segment, mostly related to the continued expansion work on the Pacific operations' East Line products pipeline, the construction of an additional refined products line on the CALNEV Pipeline in order to increase delivery service to the growing Las Vegas, Nevada market, and to the combined expansion projects at the 24 refined products terminals included within the Southeast terminal operations.

- **Kinder Morgan Energy Partners Debt Offerings** On January 30, 2007, Kinder Morgan Energy Partners completed a public offering of senior notes. Kinder Morgan Energy Partners issued a total of $1.0 billion in principal amount of senior notes, consisting of $600 million of 6.00% notes due February 1, 2017 and $400 million of 6.50% notes due February 1, 2037. Kinder Morgan Energy Partners received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $992.8 million, and used the proceeds to reduce the borrowings under its commercial paper program.

(B) Financial Information about Segments

Note 17 of the accompanying Notes to Consolidated Financial Statements contains financial information about our business segments.

(C) Narrative Description of Business

Overview

We are an energy infrastructure provider. Our principal business segments are: (1) Natural Gas Pipeline Company of America and certain affiliates, referred to as Natural Gas Pipeline Company of America or NGPL, a major interstate natural gas pipeline and storage system; (2) Kinder Morgan Canada, a refined products and crude oil transportation pipeline business; (3) Terasen Gas, a natural gas distribution business involved in the transmission and distribution of natural gas and propane for residential, commercial and industrial customers in British Columbia; (4) Power, a business that owns and operates natural gas-fired electric generation facilities; (5) Products Pipelines – KMP, the ownership and operation of refined petroleum products pipelines that deliver gasoline, diesel fuel, jet fuel and natural gas liquids to various markets plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities; (6) Natural Gas Pipelines – KMP, the ownership and operation of major interstate and intrastate natural gas pipeline and storage systems; (7) CO_2 – KMP, the production, transportation and marketing of carbon dioxide ("CO_2") to oil fields that use CO_2 to increase production of oil plus ownership interests in and/or operation of oil fields in West Texas plus the ownership and operation of a crude oil pipeline system in West Texas and (8) Terminals – KMP, the ownership and/or operation of liquids and bulk terminal facilities and rail transloading and materials handling facilities located throughout the United States. In August 2006, we reached an agreement to sell our Kinder Morgan Retail segment. Accordingly, the activities and assets related to that segment are presented as discontinued items in the accompanying consolidated financial statements. In November 2004, we contributed TransColorado Gas Transmission Company to Kinder Morgan Energy Partners for total consideration of $275 million, consisting of approximately $210 million in cash and 1.4 million Kinder Morgan Energy Partners common units. TransColorado's segment earnings of $20.3 million in 2004 prior to its contribution represented approximately 2% of our total 2004 segment earnings plus earnings attributable to our investment in Kinder Morgan Energy Partners, and approximately 2% of our 2004 income from continuing operations before interest and income taxes. In 1999, we discontinued our wholesale natural gas marketing, non-energy retail marketing services and natural gas gathering and processing businesses. Notes 5 and 17 of the accompanying Notes to Consolidated Financial Statements contain additional information on asset sales and our business segments. As discussed following, certain of our operations are regulated by various federal and state entities.

Natural gas transportation, storage and retail sales accounted for approximately 92%, 93% and 92% of our consolidated revenues in 2006, 2005 and 2004, respectively. During 2006, 2005 and 2004, we did not have revenues from any single customer that exceeded 10% of our consolidated operating revenues. Our equity in the earnings of Kinder Morgan Energy Partners (before reduction for the minority interest in Kinder Morgan Management) constituted approximately 54% and 61% of our income from continuing operations before interest and income taxes in 2005 and 2004, respectively. The following table gives our segment earnings, our earnings attributable to our investment in Kinder Morgan Energy Partners (net of pre-tax minority interest) and the percent of the combined total each represents, for each of the last two years.

	Year Ended December 31,			
	2006		2005	
	Amount	% of Total	Amount	% of Total
	(Dollars in millions)			
Net Pre-tax Impact of Kinder Morgan Energy Partners[1, 2]	$ 582.9	37.95%	$ 534.8	51.06%
Segment Earnings:				
NGPL	499.0	32.49%	435.2	41.55%
Kinder Morgan Canada	119.9	7.81%	12.5	1.20%
Terasen Gas	312.9	20.37%	45.2	4.31%
Power	21.1	1.38%	19.7	1.88%
Total	$ 1,535.8	100.00%	$ 1,047.4	100.00%

[1] For 2006, Products Pipelines – KMP, Natural Gas Pipelines – KMP, CO_2 – KMP, and Terminals – KMP represented approximately 25.0%, 29.3%, 24.9% and 20.8%, respectively, of Kinder Morgan Energy Partners' segment earnings before depreciation, depletion and amortization.

[2] Represents Kinder Morgan, Inc.'s general partner incentive and earnings from its ownership of limited partner interests in Kinder Morgan Energy Partners, net of associated minority interests.

Natural Gas Pipeline Company of America

During 2006, NGPL's segment earnings of $499 million represented approximately 32% of total segment earnings plus net pre-tax impact of Kinder Morgan Energy Partners and approximately 28% of our income from continuing operations before interest, income taxes and the impairment of goodwill on our Terasen Gas segment. Through NGPL, we own and operate approximately 9,700 miles of interstate natural gas pipelines, storage fields, field system lines and related facilities, consisting primarily of two major interconnected natural gas transmission pipelines terminating in the Chicago, Illinois metropolitan area. The system is powered by 56 compressor stations in mainline and storage service having an aggregate of approximately 1.0 million horsepower. NGPL's system has 813 points of interconnection with 34 interstate pipelines, 34 intrastate pipelines, 38 local distribution companies, 32 end users including power plants, and a number of gas producers, thereby providing significant flexibility in the receipt and delivery of natural gas. NGPL's Amarillo Line originates in the

West Texas and New Mexico producing areas and is comprised of approximately 4,400 miles of mainline and various small-diameter pipelines. Its other major pipeline, the Gulf Coast Line, originates in the Gulf Coast areas of Texas and Louisiana and consists of approximately 4,100 miles of mainline and various small-diameter pipelines. These two main pipelines are connected at points in Texas and Oklahoma by NGPL's approximately 800-mile Amarillo/Gulf Coast pipeline. In addition, NGPL owns a 50% equity interest in and operates Horizon Pipeline Company, L.L.C., a joint venture with Nicor-Horizon, a subsidiary of Nicor, Inc. This joint venture owns a natural gas pipeline in northern Illinois with a capacity of 380 MMcf per day.

NGPL provides transportation and storage services to third-party natural gas distribution utilities, marketers, producers, industrial end users and other shippers. Pursuant to transportation agreements and FERC tariff provisions, NGPL offers its customers firm and interruptible transportation, storage and no-notice services, and interruptible park and loan services. Under NGPL's tariffs, firm transportation customers pay reservation charges each month plus a commodity charge based on actual volumes transported, including a fuel charge collected in kind. Interruptible transportation customers pay a commodity charge based upon actual volumes transported. Reservation and commodity charges are both based upon geographical location and time of year. Under firm no-notice service, customers pay a reservation charge for the right to have up to a specified volume of natural gas delivered but, unlike with firm transportation service, are able to meet their peaking requirements without making specific nominations. NGPL has the authority to discount its rates and to negotiate rates with customers if it has first offered service to those customers under its reservation and commodity charge rate structure. NGPL's revenues have historically been somewhat higher in the first and fourth quarters of the calendar year, reflecting higher system utilization during the colder months. During the winter months, NGPL collects higher transportation commodity revenue, higher interruptible transportation revenue, winter-only capacity revenue and higher rates on certain contracts.

NGPL's principal delivery market area encompasses the states of Illinois, Indiana and Iowa and secondary markets in portions of Wisconsin, Nebraska, Kansas, Missouri and Arkansas. NGPL is the largest transporter of natural gas to the Chicago market, and we believe that its transportation rates are very competitive in the region. In 2006, NGPL delivered an average of 1.82 trillion Btus per day of natural gas to this market. Given its strategic location at the center of the North American natural gas pipeline grid, we believe that Chicago is likely to continue to be a major natural gas trading hub for growing markets in the Midwest and Northeast.

Substantially all of NGPL's pipeline capacity is committed under firm transportation contracts ranging from one to five years. Approximately 63% of the total transportation volumes committed under NGPL's long-term firm transportation contracts as of February 13, 2007 had remaining terms of less than three years. NGPL continues to actively pursue the renegotiation, extension and/or replacement of expiring contracts, and was very successful in doing so during 2006 as discussed under "Recent Developments" elsewhere in this report. Nicor Gas Company, Peoples Gas Light and Coke Company, and Northern Indiana Public Service Company (NIPSCO) are NGPL's three largest customers in terms of operating revenues from tariff services. During 2006, approximately 50% of NGPL's operating revenues from tariff services were attributable to its eight largest customers. Contracts representing approximately 6.3% of NGPL's total long-haul, contracted firm transport capacity as of January 31, 2007 are scheduled to expire during 2007.

NGPL is one of the nation's largest natural gas storage operators with approximately 600 Bcf of total natural gas storage capacity, approximately 250 Bcf of working gas capacity and over 4.4 Bcf per day of peak deliverability from its storage facilities, which are located in major supply areas and near the markets it serves. NGPL owns and operates 13 underground storage reservoirs in eight field locations in four states. These storage assets complement its pipeline facilities and allow it to optimize pipeline deliveries and meet peak delivery requirements in its principal markets. NGPL provides firm and interruptible gas storage service pursuant to storage agreements and tariffs. Firm storage customers pay a monthly demand charge irrespective of actual volumes stored. Interruptible storage customers pay a monthly charge based upon actual volumes of gas stored.

Competition: NGPL competes with other transporters of natural gas in virtually all of the markets it serves and, in particular, in the Chicago area, which is the northern terminus of NGPL's two major pipeline segments and its largest market. These competitors include both interstate and intrastate natural gas pipelines and, historically, most of the competition has been from such pipelines with supplies originating in the United States. NGPL also faces competition from Alliance Pipeline, which began service during the 2000-2001 heating season carrying Canadian-produced natural gas into the Chicago market. However, at the same time, the Vector Pipeline was constructed for the specific purpose of transporting gas from the Chicago area to other markets, generally further north and further east. The overall impact of the increased pipeline capacity into the Chicago area, combined with additional take-away capacity and the increased demand in the area, has created a situation that remains dynamic with respect to the ultimate impact on individual transporters such as NGPL.

NGPL also faces competition with respect to the natural gas storage services it provides. NGPL has storage facilities in both market and supply areas, allowing it to offer varied storage services to customers. It faces competition from independent storage providers as well as storage services offered by other natural gas pipelines and local natural gas distribution companies.

The competition faced by NGPL with respect to its natural gas transportation and storage services is generally price-based, although there is also a significant component related to the variety, flexibility and reliability of services offered by others. NGPL's extensive pipeline system, with access to diverse supply basins and significant storage assets in both the supply and market areas, makes it a strong competitor in many situations, but most customers still have alternative sources to meet their requirements. In addition, due to the price-based nature of much of the competition faced by NGPL, its proven track record as a low-cost provider is an important factor in its success in acquiring and retaining customers. Additional competition for storage services could result from the utilization of currently underutilized storage facilities or from conversion of existing storage facilities from one use to another. In addition, existing competitive storage facilities could, in some instances, be expanded.

Kinder Morgan Canada (Formerly Terasen Pipelines)

During 2006, Kinder Morgan Canada's segment earnings of $119.9 million represented 8% of total segment earnings plus net pre-tax impact of Kinder Morgan Energy Partners and approximately 7% of our income from continuing operations before interest, income taxes and the impairment of goodwill on our Terasen Gas segment.

Terasen Pipelines (Trans Mountain) Inc.

Terasen Pipelines (Trans Mountain) Inc. ("Trans Mountain") operates a common carrier pipeline system, owned by Terasen, originating at Edmonton, Alberta for the transportation of crude petroleum, refined petroleum and iso-octane to destinations in the interior and on the west coast of British Columbia. A connecting pipeline owned by a wholly owned subsidiary delivers petroleum to refineries in the State of Washington. Another wholly owned subsidiary owns and operates a six-inch diameter, 25 mile long pipeline for the transportation of jet fuel from Vancouver area refineries and marketing terminals and from Westridge Marine Terminal to Vancouver International Airport.

Trans Mountain's pipeline is 715 miles in length and has a diameter of 24 inches for most of the line with the exception of two sections of 30-inch diameter pipeline, each having a length of approximately 51 miles. The capacity of the line out of Edmonton ranges from 225,000 bpd when heavy crude represents 20% of the total throughput to 285,000 bpd with no heavy crude. The pipeline system utilizes 11 pump stations controlled by a centralized computer system.

Trans Mountain also operates a 5.3 mile spur line from its Sumas Pump Station to the U.S. – Canada international border where it connects with a 63 mile pipeline system owned and operated by a wholly owned subsidiary. The pipeline system in Washington State has a sustainable throughput capacity of approximately 135,000 bpd when heavy crude represents approximately 25% of throughput and connects to four refineries located in northwestern Washington State. The volumes of petroleum shipped to Washington State fluctuate in response to the price levels of Canadian crude oil in relation to petroleum produced in Alaska and other offshore sources.

The Trans Mountain pipelines are constructed on freehold lands and rights-of-way held by Trans Mountain. Crossings over or under highways, railways and bridges have been constructed pursuant to orders or permits from the appropriate authorities. Substantially all of Trans Mountain's pipelines are constructed in rights-of-way granted by the Crown or the owners of privately-held lands, either in perpetuity for as long as they are used for a pipeline, or for fixed terms negotiated by Trans Mountain.

Under published tariffs for the Trans Mountain system, the tolls at December 31, including applicable terminalling and tankage charges, for transportation of light crude oil from Edmonton to principal delivery points are set forth below.

	Toll Per Barrel	
	2006	**2005**
Edmonton to Burnaby	C$1.695	C$1.741
Edmonton to Sumas	C$1.535	C$1.560
US Mainline	US$0.30	US$0.30

Tolls charged to 11 shippers represented 88% of Trans Mountain's consolidated 2006 revenues.

The petroleum transported through Trans Mountain's pipeline system originates from fields in Alberta and British Columbia. The refined and partially refined petroleum transported to Kamloops and Vancouver originates from oil refineries located in Edmonton. Petroleum delivered through Trans Mountain's pipe line system is used in markets in British Columbia and Washington State and elsewhere.

Overall Alberta crude oil supply has been increasing steadily over the past few years as a result of significant oilsands development with projects led by Shell Canada, Suncor Energy and Syncrude Canada. Further development is expected to continue into the future with expansions to existing oilsands production facilities as well as with new projects. In its moderate case, the Canadian Association of Petroleum Producers ("CAPP") has recently forecasted Western Canadian production to increase by over 2.5 million barrels per day by 2015. This supply increase will likely result in constrained pipeline export capacity from Western Canada, which supports Trans Mountain's view that both the demand for transportation services provided by Trans Mountain's pipeline and the supply of petroleum will remain strong for the foreseeable future.

In 2006, deliveries on Trans Mountain averaged 229,369 bpd. This was an increase of 4% from average 2005 deliveries of 220,886 bpd. A breakdown of total average deliveries for 2006 and 2005 is as follows:

	(bpd)	
Delivery Point:	**2006**	**2005**
Vancouver (crude petroleum)	46,417	42,482
Vancouver (refined petroleum)	49,611	60,634
Kamloops (refined petroleum)	15,040	20,366
Westridge Marine Terminal	25,206	22,782
Washington State refineries	93,095	74,622
	229,369	220,886

Throughput in the U.S. pipeline system increased by 25% from 2005 levels. The year over year increase in Trans Mountain throughput reflects first quarter 2005 refinery turnarounds in Washington State and temporary production outages in the oilsands. Throughput levels in 2005 were also influenced by refined product margins on the west coast and by crude oil price differentials for Canadian crude compared against competitive offshore supply sources.

Shipments of refined petroleum represent a significant portion of Trans Mountain's throughput. In 2006, shipments of refined petroleum and iso-octane represented 28% of throughput, as compared with 37% in 2005.

Terasen Pipelines (Corridor) Inc.

In July 1998, Trans Mountain and Terasen Inc. entered into an agreement with Shell Canada Limited (Shell) and its partners for the construction and operation of the Corridor pipeline system (Corridor Pipeline). The Corridor Pipeline is owned by our subsidiary, Terasen Pipelines (Corridor) Inc. ("Corridor") and is operated by Kinder Morgan Canada. Revenues and commercial operation commenced in May 2003, following the successful completion of construction.

The Corridor Pipeline provides for the pipeline transportation of diluted bitumen produced at the Muskeg River Mine, located approximately 43 miles north of Fort McMurray, Alberta, to a heavy oil upgrader that Shell and its partners have built adjacent to Shell's existing Scotford Refinery near Edmonton, Alberta, a distance of approximately 281 miles. A smaller diameter parallel pipeline transports recovered diluent from the upgrader back to the mine. Corridor also consists of two additional pipelines, each 27 miles in length, to provide pipeline transportation between the Scotford Upgrader and the existing trunk pipeline facilities of Trans Mountain and Enbridge Pipelines Inc. in the Edmonton area.

Express System

We own a one-third interest in the Express System. The Express System is a batch-mode, common-carrier, crude pipeline system comprised of the Express Pipeline and the Platte Pipeline. The Express System transports a wide variety of crude types produced in Alberta to markets in Petroleum Administration Defense District IV, comprised of the states in the Rocky Mountain area of the United States ("PADD IV") and Petroleum Administration Defense District II, comprised of the states in the central area of the United States ("PADD II"). The Express System also transports crude oil produced in PADD IV to downstream delivery points in PADD IV and to PADD II.

The Express Pipeline is a 780 mile, 24-inch diameter pipeline that begins at the crude pipeline hub at Hardisty, Alberta and terminates at the Casper, Wyoming facilities of the Platte Pipeline, and includes related metering and storage facilities including tanks and pump stations. At Hardisty, the Express Pipeline receives crude from certain other pipeline systems and terminals, which currently provide access to approximately 1.3 million bpd of crude moving through this delivery hub. The Express Pipeline is the major pipeline transporting Alberta crude into PADD IV.

The Express Pipeline has a design capacity of 280,000 bpd, after an expansion completed in April 2005. Receipts at Hardisty averaged 226,717 bpd during the year ended December 31, 2006, compared with 212,965 bpd during the year ended December 31, 2005.

The Platte Pipeline is a 926 mile, 20-inch diameter pipeline that runs from the crude pipeline hub at Casper, Wyoming to refineries and interconnecting pipelines in the Wood River, Illinois area, and includes related pumping and storage facilities (including tanks). The Platte Pipeline transports crude shipped on the Express Pipeline, crude produced in PADD IV and crude received in PADD II, to downstream delivery points. It is currently the only major crude pipeline transporting crude oil from PADD IV to PADD II. Various receipt and delivery points along the Platte Pipeline, with interconnections to other pipelines, enable crude to be moved to various markets in PADD IV and PADD II. The Platte Pipeline has a capacity of

150,000 bpd when shipping heavy oil and averaged 151,552 bpd east of Casper during the year ended December 31, 2006, versus 137,164 bpd for the year ended December 31, 2005.

The current Express System rate structure is a combination of committed rates and uncommitted rates. The committed rates apply to those shippers who have signed long-term (10 or 15 year) contracts with the Express System to transport crude on a ship-or-pay basis. Uncommitted rates are the rates that apply to uncommitted services whereby shippers transport oil through the Express System without a long-term commitment between the shipper and the Express System.

Committed rates vary according to the destination of shipments and the length of the term of the transportation services agreement, with those shippers committing to longer-term agreements receiving lower rates.

Express Pipeline received 105,000 bpd of additional firm service commitments to the pipeline starting April 1, 2005, bringing the total firm commitment on Express to 235,000 bpd, or 84% of its total capacity. These contracts expire in 2007, 2012, 2014 and 2015 in amounts of 1%, 40%, 11% and 32% of total capacity, respectively. These contracts provide for committed tolls for transportation on the Express System, which can be increased each year by up to 2%. The remaining capacity is made available to shippers as uncommitted capacity.

Uncommitted rates were established on a cost of service basis and can be changed in accordance with applicable regulations discussed below. See "Regulation" elsewhere in this report. The table below provides a selection of tolls at December 31.

	Toll Per Barrel (US$)	
	2006	**2005**
Hardisty, Alberta to Casper, Wyoming	$ 1.612	$ 1.552
Hardisty, Alberta to Casper, Wyoming (committed)	$ 1.313	$ 1.287
Casper, Wyoming to Wood River, Illinois	$ 1.497	$ 1.410

Competition: Trans Mountain's pipeline to the west coast of North America and the Express System pipeline to the U.S. Rocky Mountains and Midwest are two of several pipeline alternatives for Western Canadian petroleum production, and throughput on these pipelines may decline if overall petroleum production in Alberta declines or if tolls become uncompetitive compared to alternatives. Our oil transportation business competes against other pipeline providers who could be in a position to establish and offer lower tolls, which may provide a competitive advantage in new pipeline development. Throughput on Trans Mountain may decline in situations where west coast petroleum prices, net of transportation costs, are relatively lower than alternative prices in the U.S. Midwest. Throughput on the Express System may also decline as a result of reduced petroleum product demand in the U.S. Rocky Mountains.

Terasen Gas

On February 26, 2007, we entered into a definitive agreement to sell Terasen Inc. to Fortis Inc. (TSX: FTS), a Canada-based company with investments in regulated distribution utilities, for approximately $3.2 billion (C$3.7 billion) including cash and assumed debt. Terasen Inc.'s principal assets include Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. The transaction is subject to certain closing conditions and regulatory approvals and is expected to close in mid 2007. This sale does not include assets of Kinder Morgan Canada.

During 2006, Terasen Gas' segment earnings of $312.9 million represented 20% of total segment earnings plus net pre-tax impact of Kinder Morgan Energy Partners and approximately 18% of our income from continuing operations before interest, income taxes and the impairment of goodwill on our Terasen Gas segment.

Terasen Gas Inc.

Terasen Gas Inc. provides service to more than 100 communities with a service territory that has an estimated population of approximately 4.3 million. Terasen Gas Inc. is one of the largest natural gas distribution companies in Canada. As of December 31, 2006, Terasen Gas Inc. and its subsidiaries transported and distributed natural gas to 815,032 residential, commercial and industrial customers, representing approximately 87% of the natural gas users in British Columbia. Terasen Gas Inc.'s service area extends from Vancouver to the Fraser Valley and the interior of British Columbia. The transmission and distribution business is carried on under statutes and franchises or operating agreements granting the right to operate in the municipalities or areas served. Terasen Gas Inc. is regulated by the British Columbia Utilities Commission ("BCUC").

Terasen Gas Inc. provides natural gas distribution services to residential, small commercial and industrial heating customers predominantly on a non-contractual basis, whereby the customers are charged based on general services provided. Larger commercial and industrial customers are normally provided with services on a contractual basis.

Terasen Gas Inc. has approximately 1,956 commercial and industrial customers that arrange for some or all of their own gas supply and use Terasen Gas Inc.'s transportation services for delivery. Notwithstanding shifts over time between utility supply and direct purchases, Terasen Gas Inc.'s earnings remain unaffected since Terasen Gas Inc.'s margins remain substantially the same whether or not customers choose to buy natural gas from Terasen Gas Inc. or arrange their own supply. Customers arranging for their own supply in fact reduce the credit risk to Terasen Gas Inc.

Of Terasen Gas Inc.'s industrial customers, 143 are on interruptible service. The majority of these customers are capable of switching to alternative fuels. Forecast variances in industrial consumption can have an impact on Terasen Gas Inc.'s earnings. However, forecasts are updated annually based largely on the results of an annual survey of industrial customers.

Of the various industries that comprise Terasen Gas Inc.'s industrial market, the pulp and paper and wood products industries combined comprise approximately 47% of total consumption. All other industries individually represent less than 10% of total consumption.

In order to acquire supply resources that ensure reliable natural gas deliveries to its customers, Terasen Gas Inc. purchases supply from a select list of producers, aggregators, and marketers by adhering to strict standards of counterparty creditworthiness, and contract execution/management procedures. Terasen Gas Inc. contracts for approximately 140 PJ of baseload and seasonal supply, of which, 95 PJ is delivered off the Duke Energy Gas Transmission system, and 25 PJ is comprised of Alberta-sourced supply transported into British Columbia via TransCanada Pipelines Limited ("TransCanada") Alberta and British Columbia systems. The remaining 20 PJ of baseload and seasonal supply is sourced at Sumas. The majority of supply contracts in the current portfolio are one year in length, with the exception of one long-term contract expiring in October 2009.

Terasen Gas Inc. serves Greater Vancouver and the Fraser Valley through a transmission and distribution system that connects to the Duke Energy Gas Transmission pipeline near Huntingdon, British Columbia. This transmission system also supplies gas to Terasen Gas (Vancouver Island) Inc. for delivery to the Sunshine Coast, Vancouver Island and to Terasen Gas (Squamish) Inc., a subsidiary of Terasen Gas Inc., for distribution in Squamish, British Columbia. In addition, Terasen Gas Inc. is connected at Huntingdon to Northwest Pipeline to facilitate gas movement both north and south. Effective January 1, 2007, Terasen Gas (Squamish) Inc. has amalgamated with Terasen Gas Inc.

In the interior of British Columbia, Terasen Gas Inc. serves municipalities with numerous connections to the Duke pipeline system. Communities in the East Kootenay region of British Columbia are served through connections with TransCanada's British Columbia system. Terasen Gas Inc. is connected to TransCanada's British Columbia system through Terasen Gas Inc.'s Southern Crossing Pipeline between Yahk and Oliver. Terasen Gas Inc. also operates a propane distribution system in Revelstoke, British Columbia.

The Duke and TransCanada transportation tolls are regulated by the National Energy Board ("NEB"). Terasen Gas Inc. pays both fixed and variable charges for use of the pipelines, which are recovered through rates paid by Terasen Gas Inc.'s customers.

Terasen Gas Inc. incorporates peak shaving and gas storage facilities into its portfolio to:

1. Manage the load factor of baseload supply contracts throughout the year.
2. Eliminate the risk of supply shortages during a peak throughput day.
3. Reduce the cost of gas during winter months.
4. Balance daily supply and demand on the distribution system.
5. Supplement its baseload supply sources at times when the demand for natural gas is greatest.

Terasen Gas Inc.'s peak shaving and storage assets and contracts for 2007 include the following:

1. Liquefied natural gas (LNG) plant: The plant is located on Tilbury Island in Delta, British Columbia, and has a capacity of approximately 660 TJ with a maximum daily deliverability rate of 165 TJ.
2. Carbon Storage: Atco Midstream Ltd. owns and operates the Carbon storage facility in Alberta. The contract provides for 3 PJ of capacity with a maximum daily deliverability of 28 TJ.
3. Aitken Creek Storage: Terasen Gas Inc. has storage contracts with Unocal Canada Limited which provide 20 PJ of capacity at the Aitken Creek storage facility in British Columbia, with a daily deliverability rate of 135 TJ.
4. Jackson Prairie Storage: The Jackson Prairie storage facility is jointly owned by two U.S. Pacific Northwest gas utilities and Northwest Pipeline near Chehalis, Washington. Terasen Gas Inc. is a party to three storage lease

agreements that provide the right to approximately 3 PJ of capacity, with a maximum daily deliverability rate of about 130 TJ.

5. Mist Storage: Terasen Gas Inc. has two contracts with Northwest Natural Gas Company for natural gas storage in Oregon. The contracts provide a total capacity of approximately 3 PJ with a maximum daily deliverability rate of 115 TJ.

Terasen Gas Inc. is eligible for incentives under the Gas Supply Mitigation Incentive Plan established with the BCUC relating to its off-system sales activities and capacity release of excess transportation and storage capacity. For the 2007 Gas Year which runs from November 2006 to October 2007, Terasen Gas Inc. has marketed approximately 27.6 PJ of surplus gas and 56.1 PJ of excess pipeline and storage capacity up to December 31, 2006, which resulted in margins eligible for incentives totaling C$39.9 million (pre-tax), of which C$1.3 million (pre-tax) accrued to Terasen Gas Inc.

As of December 31, 2006, Terasen Gas Inc. had 24,000 miles of pipelines for use in natural gas transmission and distribution. In addition to the pipelines, Terasen Gas Inc. owns properties and equipment utilized for service shops, warehouses, metering, and regulating stations, as well as its main operations center in Surrey, British Columbia.

Terasen Gas Inc.'s pipelines are constructed for the most part under highways and streets pursuant to permits or orders from the appropriate authorities, franchise or operating agreements entered into with municipalities and rights-of-way held directly or jointly with British Columbia Hydro & Power Authority ("B.C. Hydro"). Compressor stations and major regulator stations are located on freehold land, rights-of-way owned by Terasen Gas Inc. or properties shared with B.C. Hydro.

Terasen Gas Inc. currently holds operating agreements with all of the incorporated municipalities in which it distributes gas in the Greater Vancouver and Fraser Valley service areas, other than Richmond, British Columbia. The operating agreements are in force so long as the distribution lines of Terasen Gas Inc. are operative and do not contain any provision entitling the municipality to purchase the distribution system. No fees are payable by Terasen Gas Inc. under these operating agreements.

Terasen Gas Inc. currently holds franchise or operating agreements with most of the incorporated municipalities in which it distributes gas in the interior of British Columbia. Historically, approximately one-quarter of these franchise agreements contained a provision to the effect that at the end of the term the municipality could purchase the distribution system within the municipality as a going concern and at a price equal to the fair value of the business undertaking. If the municipality did not exercise the right to purchase or grant a new franchise or operating agreement, the gas utility would be required under the Utilities Commission Act to continue to provide service in the municipality unless the BCUC ordered otherwise. While such franchise agreements are in effect, the municipalities receive franchise fees of three per cent of the gross revenue from customers in the municipality. The term of the franchise agreements ranges from 10 to 21 years. Some have expired and Terasen Gas Inc. is currently negotiating renewals and extensions with the remaining municipalities, some of which have a right to purchase the distribution system within their boundaries. For those municipalities with the right to purchase those distribution systems, an arrangement has been developed to transfer the economic risks and rewards of ownership to the municipality, while allowing Terasen Gas Inc. to continue to operate within the municipality.

These arrangements have been entered into with five municipalities to date. In each of the transactions, Terasen Gas Inc. entered into an arrangement whereby the municipality leased Terasen Gas Inc.'s gas distribution assets within the municipality's boundaries for a term of 35 years for an initial cash payment. Terasen Gas Inc. in turn entered into a 17 year operating lease with the municipality whereby Terasen Gas Inc. will operate the gas distribution assets. Terasen Gas Inc. has the option to terminate the lease of the assets to the municipality at the end of 17 years in exchange for a payment to the municipality equal to the depreciated value of the leased assets. As of December 31, 2006, Terasen Gas Inc. had entered into such arrangements involving a total value of C$153 million.

Terasen Gas (Vancouver Island) Inc.

Terasen Gas (Vancouver Island) Inc. ("TGVI") owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia. The combined system consists of 382 miles of natural gas transmission pipelines and 3,300 miles of distribution pipelines, some of which are under water. The combined system has a designed throughput capacity of 155 TJ per day. TGVI serves approximately 87,369 residential, commercial and industrial customers along the Sunshine Coast and in various communities on Vancouver Island including Victoria and surrounding areas, including seven pulp and paper mills on Vancouver Island and the Sunshine Coast and a natural gas-fired electricity generation facility on Vancouver Island. During 2006, TGVI delivered approximately 27.7 petajoules of gas through its system. The rate base of TGVI as of December 31, 2006 was approximately C$468.4 million.

TGVI provides gas transportation service to the seven pulp and paper mills under a long-term transportation service agreement that was amended in December 2004 to extend it beyond the original renewal period by two years to December 31, 2012. The maximum daily volume of firm transportation service under the agreement was 20 TJ per day for 2005. In

2006, the maximum daily volume changes to 12.5 TJ per day for the remainder of the renewal period. TGVI also delivers gas on both a firm (45.0 TJ per day) and interruptible basis to the gas-fired cogeneration plant at Elk Falls on Vancouver Island.

In order to acquire effective supply resources that ensure reliable natural gas deliveries to its customers, TGVI purchases supply from a select list of producers, aggregators, and marketers by adhering to strict standards of counterparty credit worthiness, and contract execution/management procedures. TGVI contracts for approximately 37.6 TJ per day of seasonal supply to meet load during the months from November 2006 to March 2007. TGVI further contracts 9.5 TJ per day of seasonal supply to meet the higher loads during the winter months from December 2006 to February 2007. 15 TJ per day of supply is contracted to meet the load requirement during summer from April 2007 to October 2007. The supply contracts in the current portfolio are for one season in length (i.e. either November to March for winter supply or April to October for summer supply).

Terasen Gas (Whistler) Inc.

Terasen Gas (Whistler) Inc. ("Whistler Gas") distributes piped propane gas to approximately 2,370 residential and commercial customers in the Whistler area of British Columbia. Whistler Gas owns and operates two propane storage and vaporization plants and approximately 80 miles of distribution pipelines serving customers in the Whistler area. Whistler Gas is regulated by the BCUC. The rate base of Whistler Gas at December 31, 2006 was approximately C$17.0 million.

Competition: Natural gas has maintained a competitive advantage in terms of pricing when compared with alternative sources of energy in British Columbia, despite the significant increase in natural gas commodity prices since 1999. However, because electricity prices in British Columbia continue to be set based on the historical average cost of production, rather than based on market forces, they have remained artificially low compared to market-priced electricity and, as a result, only marginally higher than comparable, market-based natural gas costs. A further sustained increase in natural gas commodity prices could cause natural gas in British Columbia to be uncompetitive with electricity, thereby decreasing the use of natural gas by customers.

Power

Power's 2006 earnings represented approximately 1% of each of our total segment earnings plus net pre-tax impact of Kinder Morgan Energy Partners and our income from continuing operations before interest, income taxes and the impairment of goodwill on our Terasen Gas segment. We currently have ownership interests in two natural gas-fired electricity generation facilities in Colorado and one natural gas-fired electricity generation facility in Michigan. We also have a net profits interest in a third natural gas-fired electricity generation facility in Colorado. One of the Colorado facilities is operated as an independent power producer, with both a long-term power sales agreement and gas supply contract. The other Colorado facility and the Michigan facility are operated under tolling agreements. Under the tolling agreements, purchasers of the electrical output take the risks in the marketplace associated with the cost of fuel and the value of the electric power generated. Kinder Morgan Power's customers include power marketers and utilities. During 2006, approximately 64% of Power's operating revenues represented tolling revenues of the Michigan facility, 24% was derived from the Colorado facility operated as an independent power producer under a long-term contract with XCEL Energy's Public Service Company of Colorado unit, and the remaining 12% were primarily for operating the Ft. Lupton, Colorado power facility and a gas-fired power facility in Snyder, Texas that began operations during the second quarter of 2005 and provides electricity to Kinder Morgan Energy Partners' SACROC operations. In recent periods, we have recorded impairment charges associated with our power business activities; see Note 6 of the accompanying Notes to Consolidated Financial Statements.

Kinder Morgan Power previously designed, developed and constructed power projects. In 2002, following an assessment of the electric power industry's business environment and noting a marked deterioration in the financial condition of certain power generating and marketing participants, we decided to discontinue our power development activities.

In February 2001, Kinder Morgan Power announced an agreement under which Williams Energy Marketing and Trading agreed to supply natural gas to and market capacity for 16 years for a 550 megawatt natural gas-fired Orion technology (discussed below) electric power plant in Jackson, Michigan. Effective July 1, 2002, construction of this facility was completed and commercial operations commenced. Concurrently with commencement of commercial operations, (i) Kinder Morgan Power made a preferred investment in Triton Power Company LLC (now valued at approximately $119 million); and, (ii) Triton Power Company LLC, through its wholly owned subsidiary, Triton Power Michigan LLC, entered into a 40-year lease of the Jackson power facility from the plant owner, AlphaGen Power, LLC. Williams Energy Marketing and Trading supplies all natural gas to and purchases all power from the power plant under a 16-year tolling agreement with Triton Power Michigan LLC.

In 1998, Kinder Morgan Power acquired interests in the Thermo Companies, which provided us with our first electric generation assets as well as knowledge and expertise with General Electric Company jet engines (LMs) configured in a combined cycle mode. Through the Thermo Companies, Kinder Morgan Power acquired the interests in three Colorado natural gas-fired electric generating facilities discussed above, which have a combined 380 megawatts of electric generation capacity. Kinder Morgan Power used the LM knowledge to develop its proprietary "Orion" technology. Pursuant to a right we obtained in conjunction with the 1998 acquisition of the Thermo Companies, in December 2003, we made an additional investment in the Thermo Companies in the form of approximately 1.8 million Kinder Morgan Management shares that we owned. We delivered these shares to an entity controlled by the former Thermo owners. For further information regarding this incremental investment, see "Power" within "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Competition: With respect to the electric generating facilities acquired from the Thermo entities, Kinder Morgan Power does not directly face competition with respect to the sale of the power generated, as it is sold to or generated for the local electric utility under long-term contracts. With respect to Power's investment in the Jackson, Michigan facility, the principal impact of competition is the level of dispatch of the plant and the related (but minor) effect on profitability.

Products Pipelines – KMP

The Products Pipelines – KMP segment consists of Kinder Morgan Energy Partners' refined petroleum products and natural gas liquids pipelines and associated terminals, Southeast terminals and transmix processing facilities.

Pacific Operations

The Pacific operations include Kinder Morgan Energy Partners' SFPP, L.P. operations, CALNEV Pipeline operations and West Coast terminals operations. The assets include interstate common carrier pipelines regulated by the FERC, intrastate pipelines in the State of California regulated by the California Public Utilities Commission, and certain non rate-regulated operations and terminal facilities.

The Pacific operations serve seven western states with approximately 3,000 miles of refined petroleum products pipelines and related terminal facilities that provide refined products to some of the fastest growing population centers in the United States, including California; Las Vegas and Reno, Nevada; and the Phoenix-Tucson, Arizona corridor. For 2006, the three main product types transported were gasoline (61%), diesel fuel (22%) and jet fuel (17%).

The Pacific operations' pipeline system consists of seven pipeline segments, which include the following:

- the West Line, which consists of approximately 515 miles of primary pipeline and currently transports products for 37 shippers from six refineries and three pipeline terminals in the Los Angeles Basin to Phoenix, Arizona and various intermediate commercial and military delivery points. Products for the West Line also come through the Los Angeles and Long Beach port complexes;

- the East Line, which is comprised of two parallel pipelines, 12-inch/16-inch diameter and 8-inch/12-inch diameter, originating in El Paso, Texas and continuing approximately 300 miles west to Kinder Morgan Energy Partners' Tucson terminal, and one 12-inch diameter line continuing northwest approximately 130 miles from Tucson to Phoenix. Products received by the East Line at El Paso come from a refinery in El Paso and through interconnections with non-affiliated pipelines;

- the San Diego Line, which is a 135-mile pipeline serving major population areas in Orange County (immediately south of Los Angeles) and San Diego. The same refineries and terminals that supply the West Line also supply the San Diego Line;

- the CALNEV Line, which consists of two parallel 248-mile, 14-inch and 8-inch diameter pipelines that run from Kinder Morgan Energy Partners' facilities at Colton, California to Las Vegas, Nevada, and which also serves Nellis Air Force Base located in Las Vegas. It also includes approximately 55 miles of pipeline serving Edwards Air Force Base;

- the North Line, which consists of approximately 864 miles of trunk pipeline in five segments that transport products from Richmond and Concord, California to Brisbane, Sacramento, Chico, Fresno, Stockton and San Jose, California, and Reno, Nevada. The products delivered through the North Line come from refineries in the San Francisco Bay Area and from various pipeline and marine terminals;

- the Bakersfield Line, which is a 100-mile, 8-inch diameter pipeline serving Fresno, California; and

- the Oregon Line, which is a 114-mile pipeline transporting products to Eugene, Oregon for 18 shippers from marine terminals in Portland, Oregon and from the Olympic Pipeline.

The Pacific operation's West Coast terminals are fee-based terminals located in several strategic locations along the west coast of the United States with a combined total capacity of approximately 8.3 million barrels of storage for both petroleum products and chemicals. The Carson terminal and the connected Los Angeles Harbor terminal are located near the many refineries in the Los Angeles Basin. The combined Carson/LA Harbor system is connected to numerous other pipelines and facilities throughout the Los Angeles area, which gives the system significant flexibility and allows customers to quickly respond to market conditions.

The Richmond terminal is located in the San Francisco Bay Area. The facility serves as a storage and distribution center for chemicals, lubricants and paraffin waxes. It is also the principal location in northern California through which tropical oils are imported for further processing, and from which United States' produced vegetable oils are exported to consumers in the Far East. The Pacific operations also have two petroleum product terminals located in Portland, Oregon and one in Seattle, Washington.

The Pacific operations include 15 truck-loading terminals (13 on SFPP, L.P. and two on CALNEV) with an aggregate usable tankage capacity of approximately 13.5 million barrels. The truck terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and oxygenate blending.

Markets. Combined, the Pacific operations' pipelines transport approximately 1.2 million barrels per day of refined petroleum products, providing pipeline service to approximately 31 customer-owned terminals, 11 commercial airports and 14 military bases. Currently, the Pacific operations' pipelines serve approximately 93 shippers in the refined petroleum products market; the largest customers being major petroleum companies, independent refiners, and the United States military.

A substantial portion of the product volume transported is gasoline. Demand for gasoline depends on such factors as prevailing economic conditions, vehicular use patterns and demographic changes in the markets served. If current trends continue, we expect the majority of the Pacific operations' markets to maintain growth rates that will exceed the national average for the foreseeable future. Currently, the California gasoline market is approximately one million barrels per day. The Arizona gasoline market, which is served primarily by the Pacific operations, is approximately 178,000 barrels per day. Nevada's gasoline market is approximately 71,000 barrels per day and Oregon's is approximately 100,000 barrels per day. The diesel and jet fuel market is approximately 545,000 barrels per day in California, 86,000 barrels per day in Arizona, 33,000 barrels per day in Nevada and 62,000 barrels per day in Oregon.

The volume of products transported is affected by various factors, principally demographic growth, economic conditions, product pricing, vehicle miles traveled, population and fleet mileage. Certain product volumes can experience seasonal variations and, consequently, overall volumes may be lower during the first and fourth quarters of each year.

Supply. The majority of refined products supplied to the Pacific operations' pipeline system come from the major refining centers around Los Angeles, San Francisco and Puget Sound, as well as from waterborne terminals located near these refining centers.

Competition. The most significant competitors of the Pacific operations' pipeline system are proprietary pipelines owned and operated by major oil companies in the area where the Pacific operations' pipeline system delivers products as well as refineries with related terminal and trucking arrangements within the Pacific operations' market areas. We believe that high capital costs, tariff regulation, and environmental and right-of-way permitting considerations make it unlikely that a competing pipeline system comparable in size and scope to the Pacific operations will be built in the foreseeable future. However, the possibility of individual pipelines being constructed or expanded to serve specific markets is a continuing competitive factor.

The use of trucks for product distribution from either shipper-owned proprietary terminals or from their refining centers continues to compete for short haul movements by pipeline. We cannot predict with any certainty whether the use of short haul trucking will decrease or increase in the future.

Longhorn Partners Pipeline is a pipeline that transports refined products from refineries on the Gulf Coast to El Paso and other destinations in Texas. Increased product supply in the El Paso area has resulted in some shift of volumes transported into Arizona from the West Line to the East Line. Increased movements into the Arizona market from El Paso could displace lower tariff volumes supplied from Los Angeles on the West Line. Such shift of supply sourcing has not had, and is not expected to have, a material effect on our operating results.

The Pacific operation's terminals compete with terminals owned by its shippers and by third party terminal operators in Sacramento, San Jose, Stockton, Colton, Orange County, Mission Valley, and San Diego, California, Phoenix and Tucson, Arizona and Las Vegas, Nevada. Short haul trucking from the refinery centers is also a competitive factor to terminals close to the refineries. Competitors of the Carson terminal in the refined products market include Shell Oil Products U.S. and BP (formerly Arco Terminal Services Company). In the crude/black oil market, competitors include Pacific Energy, Wilmington Liquid Bulk Terminals (Vopak) and BP. Competition to the Richmond terminal's chemical business comes primarily from IMTT. Competitors to the Portland, Oregon terminals include ST Services, ChevronTexaco and Shell Oil Products U.S.

Competitors to the Seattle petroleum products terminal primarily include BP and Shell Oil Products U.S.

Plantation Pipe Line Company

Kinder Morgan Energy Partners owns approximately 51% of Plantation Pipe Line Company, a 3,100-mile refined petroleum products pipeline system serving the southeastern United States. An affiliate of ExxonMobil owns the remaining 49% ownership interest. ExxonMobil is the largest shipper on the Plantation system both in terms of volumes and revenues. Kinder Morgan Energy Partners operates the system pursuant to agreements with Plantation Services LLC and Plantation Pipe Line Company. Plantation serves as a common carrier of refined petroleum products to various metropolitan areas, including Birmingham, Alabama; Atlanta, Georgia; Charlotte, North Carolina; and the Washington, D.C. area.

For the year 2006, Plantation delivered an average of 555,060 barrels per day of refined petroleum products. These delivered volumes were comprised of gasoline (67%), diesel/heating oil (20%) and jet fuel (13%). Average delivery volumes for 2006 were 6.8% lower than the 595,248 barrels per day delivered during 2005. The decrease was predominantly driven by alternative pipeline service into Southeast markets and to changes in supply patterns from Louisiana refineries related to new ultra low sulfur diesel and ethanol blended gasoline requirements.

Markets. Plantation ships products for approximately 40 companies to terminals throughout the southeastern United States. Plantation's principal customers are Gulf Coast refining and marketing companies, fuel wholesalers, and the United States Department of Defense. Plantation's top five shippers represent approximately 82% of total system volumes.

The eight states in which Plantation operates represent a collective pipeline demand of approximately two million barrels per day of refined petroleum products. Plantation currently has direct access to about 1.5 million barrels per day of this overall market. The remaining 0.5 million barrels per day of demand lies in markets (e.g., Nashville, Tennessee; North Augusta, South Carolina; Bainbridge, Georgia; and Selma, North Carolina) currently served by another pipeline company. Plantation also delivers jet fuel to the Atlanta, Georgia; Charlotte, North Carolina; and Washington, D.C. airports (Ronald Reagan National and Dulles). Combined jet fuel shipments to these four major airports decreased 13% in 2006 compared to 2005, due primarily to a 19% decrease in shipments to Atlanta Hartsfield-Jackson International Airport and a 35% decrease in shipments to Charlotte-Douglas International airport, which was largely the result of air carriers realizing lower wholesale prices on jet fuel transported by competing pipelines.

Supply. Products shipped on Plantation originate at various Gulf Coast refineries from which major integrated oil companies and independent refineries and wholesalers ship refined petroleum products. Plantation is directly connected to and supplied by a total of ten major refineries representing approximately 2.3 million barrels per day of refining capacity.

Competition. Plantation competes primarily with the Colonial pipeline system, which also runs from Gulf Coast refineries throughout the southeastern United States and extends into the northeastern states.

Central Florida Pipeline

The Central Florida pipeline system consists of a 110-mile, 16-inch diameter pipeline that transports gasoline and an 85-mile, 10-inch diameter pipeline that transports diesel fuel and jet fuel from Tampa to Orlando, with an intermediate delivery point on the 10-inch pipeline at Intercession City, Florida. In addition to being connected to Kinder Morgan Energy Partners' Tampa terminal, the pipeline system is connected to terminals owned and operated by TransMontaigne, Citgo, BP, and Marathon Petroleum. The 10-inch diameter pipeline is connected to Kinder Morgan Energy Partners' Taft, Florida terminal (located near Orlando) and is also the sole pipeline supplying jet fuel to the Orlando International Airport in Orlando, Florida. In 2006, the pipeline system transported approximately 112,000 barrels per day of refined products, with the product mix being approximately 69% gasoline, 13% diesel fuel, and 18% jet fuel.

Kinder Morgan Energy Partners also owns and operates liquids terminals in Tampa and Taft, Florida. The Tampa terminal contains approximately 1.4 million barrels of storage capacity and is connected to two ship dock facilities in the Port of Tampa. In early 2007, a new tank will go into service, increasing storage capacity to approximately 1.5 million barrels. The Tampa terminal provides storage for gasoline, diesel fuel and jet fuel for further movement into either trucks through five truck-loading racks or into the Central Florida pipeline system. The Tampa terminal also provides storage for non-fuel products, predominantly spray oil used to treat citrus crops; ethanol; and bio-diesel. These products are delivered to the terminal by vessel or railcar and loaded onto trucks through truck-loading racks. The Taft terminal contains approximately 0.7 million barrels of storage capacity, providing storage for gasoline and diesel fuel for further movement into trucks through 13 truck-loading racks.

Markets. The estimated total refined petroleum products demand in the State of Florida is approximately 800,000 barrels per day. Gasoline is, by far, the largest component of that demand at approximately 545,000 barrels per day. The total refined petroleum products demand for the Central Florida region of the state, which includes the Tampa and Orlando markets, is estimated to be approximately 360,000 barrels per day, or 45% of the consumption of refined products in the state. Kinder

Morgan Energy Partners distributes approximately 150,000 barrels of refined petroleum products per day including the Tampa terminal truck loadings. The balance of the market is supplied primarily by trucking firms and marine transportation firms. Most of the jet fuel used at Orlando International Airport is moved through Kinder Morgan Energy Partners' Tampa terminal and the Central Florida pipeline system. The market in Central Florida is seasonal, with demand peaks in March and April during spring break and again in the summer vacation season, and is also heavily influenced by tourism, with Disney World and other amusement parks located in Orlando.

Supply. The vast majority of refined petroleum products consumed in Florida is supplied via marine vessels from major refining centers in the Gulf Coast of Louisiana and Mississippi and refineries in the Caribbean basin. A lesser amount of refined petroleum products is being supplied by refineries in Alabama and by Texas Gulf Coast refineries via marine vessels and through pipeline networks that extend to Bainbridge, Georgia. The supply into Florida is generally transported by ocean-going vessels to the larger metropolitan ports, such as Tampa, Port Everglades near Miami, and Jacksonville. Individual markets are then supplied from terminals at these ports and other smaller ports, predominately by trucks, except the Central Florida region, which is served by a combination of trucks and pipelines.

Competition. With respect to the Central Florida pipeline system, the most significant competitors are trucking firms and marine transportation firms. Trucking transportation is more competitive in serving markets close to the marine terminals on the east and west coasts of Florida. Kinder Morgan Energy Partners is utilizing tariff incentives to attract volumes to the pipeline that might otherwise enter the Orlando market area by truck from Tampa or by marine vessel into Cape Canaveral. We believe it is unlikely that a new pipeline system comparable in size and scope to the Central Florida Pipeline system will be constructed, due to the high cost of pipeline construction, tariff regulation and environmental and right-of-way permitting in Florida. However, the possibility of such a pipeline or a smaller capacity pipeline being built is a continuing competitive factor.

With respect to the terminal operations at Tampa, the most significant competitors are proprietary terminals owned and operated by major oil companies, such as Marathon Petroleum, BP and Citgo, located along the Port of Tampa, and the ChevronTexaco and Motiva terminals in Port Tampa. These terminals generally support the storage requirements of their parent or affiliated companies' refining and marketing operations and provide a mechanism for an oil company to enter into exchange contracts with third parties to serve its storage needs in markets where the oil company may not have terminal assets.

Federal regulation of marine vessels, including the requirement, under the Jones Act, that United States-flagged vessels contain double-hulls, is a significant factor influencing the availability of vessels that transport refined petroleum products. Marine vessel owners are phasing in the requirement based on the age of the vessel and some older vessels are being redeployed into use in other jurisdictions rather than being retrofitted with a double-hull for use in the United States.

North System

The North System consists of an approximate 1,600-mile interstate common carrier pipeline system that delivers natural gas liquids and refined petroleum products for approximately 50 shippers from south central Kansas to the Chicago area. Through interconnections with other major liquids pipelines, the North System's pipeline system connects mid-continent producing areas to markets in the Midwest and eastern United States. Kinder Morgan Energy Partners also has defined sole carrier rights to use capacity on an extensive pipeline system owned by Magellan Midstream Partners, L.P. that interconnects with the North System. This capacity lease agreement, which requires Kinder Morgan Energy Partners to pay approximately $2.3 million per year, is in place until February 2013 and contains a five-year renewal option.

In addition to its capacity lease agreement with Magellan, Kinder Morgan Energy Partners also has a reversal agreement with Magellan to help provide for the transport of summer-time surplus butanes from Chicago area refineries to storage facilities at Bushton, Kansas. Kinder Morgan Energy Partners has an annual minimum joint tariff commitment of $0.6 million to Magellan for this agreement. The North System has approximately 7.7 million barrels of storage capacity, which includes caverns, steel tanks, pipeline line-fill and leased storage capacity. This storage capacity provides operating efficiencies and flexibility in meeting seasonal demands of shippers and provides propane storage for Kinder Morgan Energy Partners' truck-loading terminals.

Kinder Morgan Energy Partners also owns a 50% ownership interest in the Heartland Pipeline Company, which owns the Heartland pipeline system, a natural gas liquids pipeline that ships liquids products in the Midwest. Kinder Morgan Energy Partners' equity interest in Heartland is included as part of the North System operations. ConocoPhillips owns the remaining 50% interest in the Heartland Pipeline Company. The Heartland pipeline comprises one of the North System's main line sections that originate at Bushton, Kansas and terminate at a storage and terminal area in Des Moines, Iowa. Kinder Morgan Energy Partners operates the Heartland pipeline, and ConocoPhillips operates Heartland's Des Moines, Iowa terminal and serves as the managing partner of Heartland. Heartland leases to ConocoPhillips 100% of the Heartland terminal capacity at Des Moines for $1.0 million per year on a year-to-year basis. The Heartland pipeline lease fee, payable to Kinder Morgan Energy Partners for reserved pipeline capacity, is paid monthly, with an annual adjustment. The 2007 lease fee will be approximately $1.1 million.

In addition, the North System has eight propane truck-loading terminals at various points in three states along the pipeline system and one multi-product complex at Morris, Illinois, in the Chicago area. Propane, normal butane and natural gasoline can be loaded at the North System's Morris terminal.

Markets. The North System currently serves approximately 50 shippers in the upper Midwest market, including both users and wholesale marketers of natural gas liquids. These shippers include the three major refineries in the Chicago area. Wholesale marketers of natural gas liquids primarily make direct large volume sales to major end-users, such as propane marketers, refineries, petrochemical plants and industrial concerns. Market demand for natural gas liquids varies in respect to the different end uses to which natural gas liquids products may be applied. Demand for transportation services is influenced not only by demand for natural gas liquids but also by the available supply of natural gas liquids.

Supply. Natural gas liquids extracted or fractionated at the Bushton gas processing plant have historically accounted for a significant portion (approximately 15%) of the natural gas liquids transported through the North System. Other sources of natural gas liquids transported in the North System include large oil companies, marketers, end-users and natural gas processors that use interconnecting pipelines to transport hydrocarbons. Refined petroleum products transported by Heartland on the North System are supplied primarily from the National Cooperative Refinery Association crude oil refinery in McPherson, Kansas and the ConocoPhillips crude oil refinery in Ponca City, Oklahoma. In an effort to obtain the greatest benefit from the North System's line-fill on a year round basis, Kinder Morgan Energy Partners added isobutane as a component of line-fill in 2005, and increased the proportion of normal butane and reduced the proportion of propane. We believe this restructured line-fill helps mitigate any operational constraints that could result from shippers holding reduced inventory levels at any point in the year.

Competition. The North System competes with other natural gas liquids pipelines and to a lesser extent with rail carriers. In most cases, established pipelines are the lowest cost alternative for the transportation of natural gas liquids and refined petroleum products. With respect to the Chicago market, the North System competes with other natural gas liquids pipelines that deliver into the area and with railcar deliveries primarily from Canada. Other Midwest pipelines and area refineries compete with the North System for propane terminal deliveries. The North System also competes indirectly with pipelines that deliver product to markets that the North System does not serve, such as the Gulf Coast market area. Heartland competes with other refined petroleum products carriers in the geographic market served. Heartland's principal competitor is Magellan Midstream Partners, L.P.

Cochin Pipeline System

Kinder Morgan Energy Partners owns 49.8% of the Cochin pipeline system, a joint venture that operates an approximate 1,900-mile, 12-inch diameter multi-product pipeline operating between Fort Saskatchewan, Alberta and Sarnia, Ontario, including five terminals. BP Canada Energy Company, an affiliate of BP, owns the remaining 50.2% ownership interest and is the operator of the pipeline. On January 15, 2007, Kinder Morgan Energy Partners announced that it had entered into an agreement with BP Canada Energy Company to increase its ownership interest in the Cochin pipeline system to 100%. The agreement is subject to due diligence, regulatory clearance and other standard closing conditions. The transaction is expected to close in the first quarter of 2007, and upon closing, Kinder Morgan Energy Partners will become the operator of the pipeline.

The pipeline operates on a batched basis and has an estimated system capacity of approximately 112,000 barrels per day. Its peak capacity is approximately 124,000 barrels per day. It includes 31 pump stations spaced at 60 mile intervals and five United States propane terminals. Associated underground storage is available at Fort Saskatchewan, Alberta and Windsor, Ontario.

Markets. The pipeline traverses three provinces in Canada and seven states in the United States transporting high vapor pressure ethane, propane, butane and natural gas liquids to the Midwestern United States and eastern Canadian petrochemical and fuel markets. The system operates as a National Energy Board (Canada) and FERC (United States) regulated common carrier, shipping products on behalf of its owners as well as other third parties. The system is connected to the Enterprise pipeline system in Minnesota and in Iowa, and connects with the North System at Clinton, Iowa. The Cochin pipeline system has the ability to access the Canadian Eastern Delivery System via the Windsor Storage Facility Joint Venture at Windsor, Ontario.

Supply. Injection into the system can occur from BP, EnerPro or Dow fractionation facilities at Fort Saskatchewan, Alberta; from Provident Energy storage at five points within the provinces of Canada; or from the Enterprise West Junction, in Minnesota.

Competition. The pipeline competes with railcars and Enbridge Energy Partners for natural gas liquids long-haul business from Fort Saskatchewan, Alberta and Windsor, Ontario. The pipeline's primary competition in the Chicago natural gas liquids market comes from the combination of the Alliance pipeline system, which brings unprocessed gas into the United States from Canada, and from Aux Sable, which processes and markets the natural gas liquids in the Chicago market.

Cypress Pipeline

Kinder Morgan Energy Partners' Cypress pipeline is an interstate common carrier natural gas liquids pipeline originating at storage facilities in Mont Belvieu, Texas and extending 104 miles east to a major petrochemical producer in the Lake Charles, Louisiana area. Mont Belvieu, located approximately 20 miles east of Houston, is the largest hub for natural gas liquids gathering, transportation, fractionation and storage in the United States.

Markets. The pipeline was built to service Westlake Petrochemicals Corporation in the Lake Charles, Louisiana area under a 20-year ship-or-pay agreement that expires in 2011. The contract requires a minimum volume of 30,000 barrels per day.

Supply. The Cypress pipeline originates in Mont Belvieu where it is able to receive ethane and ethane/propane mix from local storage facilities. Mont Belvieu has facilities to fractionate natural gas liquids received from several pipelines into ethane and other components. Additionally, pipeline systems that transport natural gas liquids from major producing areas in Texas, New Mexico, Louisiana, Oklahoma and the Mid-Continent Region supply ethane and ethane/propane mix to Mont Belvieu.

Competition. The pipeline's primary competition into the Lake Charles market comes from Louisiana onshore and offshore natural gas liquids.

Southeast Terminals

Kinder Morgan Energy Partners' Southeast terminal operations consist of Kinder Morgan Southeast Terminals LLC and its consolidated affiliate, Guilford County Terminal Company, LLC. Kinder Morgan Southeast Terminals LLC, a wholly-owned subsidiary referred to in this report as KMST, was formed in 2003 for the purpose of acquiring and operating high-quality liquid petroleum products terminals located primarily along the Plantation/Colonial pipeline corridor in the Southeastern United States.

Since its formation, KMST has acquired 24 petroleum products terminals with a total storage capacity of approximately 7.8 million barrels. These terminals transferred approximately 347,000 barrels of refined products per day during 2006.

The 24 terminals consist of the following:

- seven petroleum products terminals acquired from ConocoPhillips and Phillips Pipe Line Company in December 2003. The terminals are located in the following markets: Selma, North Carolina; Charlotte, North Carolina; Spartanburg, South Carolina; North Augusta, South Carolina; Doraville, Georgia; Albany, Georgia; and Birmingham, Alabama. The terminals contain approximately 1.2 million barrels of storage capacity. ConocoPhillips has entered into a long-term contract with Kinder Morgan Energy Partners to use the terminals. All seven terminals are served by the Colonial Pipeline and three are also connected to the Plantation Pipeline;

- seven petroleum products terminals acquired from Exxon Mobil Corporation in March 2004. The terminals are located at the following locations: Newington, Virginia; Richmond, Virginia; Roanoke, Virginia; Greensboro, North Carolina; Charlotte, North Carolina; Knoxville, Tennessee; and Collins, Mississippi. The terminals have a combined storage capacity of approximately 3.2 million barrels for gasoline, jet fuel and diesel fuel. ExxonMobil has entered into a long-term contract to use the terminals. All seven of these terminals are connected to products pipelines owned by either Plantation Pipe Line Company or Colonial Pipeline Company;

- nine petroleum products terminals acquired from Charter Terminal Company and Charter-Triad Terminals in November 2004. Three terminals are located in Selma, North Carolina, and the remaining facilities are located in Greensboro and Charlotte, North Carolina; Chesapeake and Richmond, Virginia; Athens, Georgia; and North Augusta, South Carolina. The terminals have a combined storage capacity of approximately 3.2 million barrels for gasoline, jet fuel and diesel fuel. Kinder Morgan Energy Partners fully owns seven of the terminals and jointly owns the remaining two. All nine terminals are connected to Plantation or Colonial pipelines; and

- one petroleum products terminal acquired from Motiva Enterprises, LLC in December 2006. The terminal, located in Roanoke, Virginia, has storage capacity of approximately 180,000 barrels per day for refined petroleum products and is served exclusively by the Plantation Pipeline. Motiva Enterprises, LLC has entered into a long-term contract to use the terminal.

Markets. KMST's acquisition and marketing activities are focused on the Southeastern United States from Mississippi through Virginia, including Tennessee. The primary function involves the receipt of petroleum products from common carrier pipelines, short-term storage in terminal tankage, and subsequent loading onto tank trucks. Longer term storage is also available at many of the terminals. KMST has a physical presence in markets representing almost 80% of the pipeline-supplied demand in the Southeast and offers a competitive alternative to marketers seeking a relationship with a truly independent truck terminal service provider.

Supply. Product supply is predominately from Plantation and/or Colonial pipelines. To the maximum extent practicable, we endeavor to connect KMST terminals to both Plantation and Colonial.

Competition. There are relatively few independent terminal operators in the Southeast. Most of the refined petroleum products terminals in this region are owned by large oil companies (BP, Motiva, Citgo, Marathon, and Chevron) who use these assets to support their own proprietary market demands as well as product exchange activity. These oil companies are not generally seeking third party throughput customers. Magellan Midstream Partners and TransMontaigne Product Services represent the other independent terminal operators in this region.

Transmix Operations

Kinder Morgan Energy Partners' Transmix operations include the processing of petroleum pipeline transmix, a blend of dissimilar refined petroleum products that have become co-mingled in the pipeline transportation process. During transportation, different products are transported through the pipelines abutting each other, and the volume of different mixed products is called transmix. At transmix processing facilities, pipeline transmix is processed and separated into pipeline-quality gasoline and light distillate products. Kinder Morgan Energy Partners processes transmix at six separate processing facilities located in Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; Indianola, Pennsylvania; Wood River, Illinois; and Greensboro, North Carolina.

At the Dorsey Junction, Maryland facility, transmix processing is performed for Colonial Pipeline Company on a "for fee" basis pursuant to a long-term contract that expires in 2012. Transmix is processed on a "for fee" basis for Shell Trading (U.S.) Company, referred to as Shell, according to the provisions of a long-term contract that expires in 2011 at Kinder Morgan Energy Partners' transmix facilities located in Richmond, Virginia; Indianola, Pennsylvania; and Wood River, Illinois. At these locations, Shell procures transmix supply from pipelines and other parties, pays a processing fee to Kinder Morgan Energy Partners, and then sells the processed gasoline and fuel oil through their marketing and distribution networks. The arrangement includes a minimum annual processing volume and a per barrel fee to Kinder Morgan Energy Partners, as well as an opportunity to extend the processing agreement beyond 2011.

The Colton processing facility is located adjacent to the products terminal in Colton, California, and it produces refined petroleum products that are delivered into the Pacific operations' pipelines for shipment to markets in Southern California and Arizona. The facility can process over 5,000 barrels of transmix per day. In June 2006, Duke Energy Merchants exercised an early termination provision contained in Kinder Morgan Energy Partners' long term processing contract due to expire in 2010. Following Duke's exercise, Kinder Morgan Energy Partners transitioned to processing transmix at Colton for various pipeline shippers directly on a "for fee" basis arrangement.

The Richmond, Virginia processing facility is supplied by the Colonial and Plantation pipelines as well as deep-water barges (25 feet draft), transport truck and rail. The facility can process approximately 7,500 barrels per day. The Dorsey Junction processing facility is located within Colonial's Dorsey Junction terminal facility, near Baltimore, Maryland. The facility can process approximately 5,000 barrels per day. The Indianola processing facility is located near Pittsburgh, Pennsylvania and is accessible by truck, barge and pipeline. It primarily processes transmix from the Buckeye, Colonial, Sun and Teppco pipelines. It has capacity to process 12,000 barrels of transmix per day. The Wood River processing facility is constructed on property owned by ConocoPhillips and is accessible by truck, barge and pipeline. It primarily processes transmix from both the Explorer and ConocoPhillips pipelines. It has capacity to process 5,000 barrels of transmix per day.

In the second quarter of 2006, Kinder Morgan Energy Partners completed construction and placed into service its approximately $11 million Greensboro, North Carolina transmix facility, which is located along KMST's refined products tank farm. The facility includes an atmospheric distillation column with a direct fired natural gas heater to process up to 6,000 barrels of transmix per day for Plantation and other interested parties. In addition to providing additional processing business, the facility also gives Plantation a lower cost alternative that recovers ultra low sulfur diesel, and more fully utilizes current KMST tankage at the Greensboro, North Carolina tank farm.

Markets. The Gulf and East Coast refined petroleum products distribution system, particularly the Mid-Atlantic region, is the target market for Kinder Morgan Energy Partners' East Coast transmix processing operations. The Mid-Continent area and the New York Harbor are the target markets for Kinder Morgan Energy Partners' Illinois and Pennsylvania assets, respectively. Kinder Morgan Energy Partners' West Coast transmix processing operations support the markets served by its Pacific operations in Southern California.

Supply. Transmix generated by Colonial, Plantation, Sun, Teppco, Explorer and Kinder Morgan Energy Partners' Pacific operations provide the vast majority of the supply. These suppliers are committed to the use of Kinder Morgan Energy Partners' transmix facilities under long-term contracts. Individual shippers and terminal operators provide additional supply. Shell acquires transmix for processing at Indianola, Richmond and Wood River; Colton is supplied by pipeline shippers of Kinder Morgan Energy Partners' Pacific operations; and Dorsey Junction is supplied by Colonial Pipeline Company.

Competition. Placid Refining is Kinder Morgan Energy Partners' main competitor in the Gulf Coast area. There are various processors in the Mid-Continent area, primarily ConocoPhillips, Gladieux Refining and Williams Energy Services, who compete with Kinder Morgan Energy Partners' transmix facilities. A new transmix facility located near Linden, New Jersey and owned by Motiva Enterprises LLC is the principal competition for New York Harbor transmix supply and for the Indianola facility. A number of smaller organizations operate transmix processing facilities in the West and Southwest. These operations compete for supply that we envision as the basis for growth in the West and Southwest. The Colton processing facility also competes with major oil company refineries in California.

Natural Gas Pipelines – KMP

The Natural Gas Pipelines – KMP segment, which contains both interstate and intrastate pipelines, consists of natural gas sales, transportation, storage, gathering, processing and treating. Within this segment, Kinder Morgan Energy Partners owns approximately 14,000 miles of natural gas pipelines and associated storage and supply lines that are strategically located at the center of the North American pipeline grid. The transportation network provides access to the major gas supply areas in the western United States, Texas and the Midwest, as well as major consumer markets.

Texas Intrastate Natural Gas Pipeline Group

The group, which operates primarily along the Texas Gulf Coast, consists of the following four natural gas pipeline systems:

- Kinder Morgan Texas Pipeline;
- Kinder Morgan Tejas Pipeline;
- Mier-Monterrey Mexico Pipeline; and
- Kinder Morgan North Texas Pipeline.

The two largest systems in the group are Kinder Morgan Texas Pipeline and Kinder Morgan Tejas Pipeline. These pipelines essentially operate as a single pipeline system, providing customers and suppliers with improved flexibility and reliability. The combined system includes approximately 6,000 miles of intrastate natural gas pipelines with a peak transport and sales capacity of approximately 5.2 billion cubic feet per day of natural gas and approximately 120 billion cubic feet of on-system contracted natural gas storage capacity. In addition, the system, through owned assets and contractual arrangements with third parties, has the capability to process 915 million cubic feet per day of natural gas for liquids extraction and to treat approximately 250 million cubic feet per day of natural gas for carbon dioxide removal.

Collectively, the system primarily serves the Texas Gulf Coast, transporting, processing and treating gas from multiple onshore and offshore supply sources to serve the Houston/Beaumont/Port Arthur, Texas industrial markets, as well as local gas distribution utilities, electric utilities and merchant power generation markets. It serves as a buyer and seller of natural gas, as well as a transporter of natural gas. The purchases and sales of natural gas are primarily priced with reference to market prices in the consuming region of its system. The difference between the purchase and sale prices is the rough equivalent of a transportation fee and fuel costs.

Included in the operations of the Kinder Morgan Tejas system is the Kinder Morgan Border Pipeline system. Kinder Morgan Border owns and operates an approximately 97-mile, 24-inch diameter pipeline that extends from a point of interconnection with the pipeline facilities of Pemex Gas Y Petroquimica Basica at the International Border between the United States and Mexico, to a point of interconnection with other intrastate pipeline facilities of Kinder Morgan Tejas located at King Ranch, Kleburg County, Texas. The 97-mile pipeline, referred to as the import/export facility, is capable of importing Mexican gas into the United States, and exporting domestic gas to Mexico. The imported Mexican gas is received from, and the exported domestic gas is delivered to, Pemex. The capacity of the import/export facility is approximately 300 million cubic feet of natural gas per day.

The Mier-Monterrey Pipeline consists of a 95-mile, 30-inch diameter natural gas pipeline that stretches from south Texas to Monterrey, Mexico and can transport up to 375 million cubic feet per day. The pipeline connects to a 1,000-megawatt power plant complex and to the PEMEX natural gas transportation system. Kinder Morgan Energy Partners has entered into a long-term contract (expiring in 2018) with Pemex, which has subscribed for all of the pipeline's capacity.

The North Texas Pipeline consists of an 86-mile, 30-inch diameter pipeline that transports natural gas from an interconnect with NGPL in Lamar County, Texas to a 1,750-megawatt electric generating facility located in Forney, Texas, 15 miles east of Dallas, Texas. It has the capacity to transport 325 million cubic feet per day of natural gas and is fully subscribed under a contract that expires in 2032. In 2006, the existing system was enhanced to be bi-directional, so that deliveries of additional supply coming out of the Barnett Shale area can be delivered into NGPL's pipeline as well as power plants in the area.

Kinder Morgan Energy Partners also owns and operates various gathering systems in South and East Texas. These systems aggregate natural gas supplies into Kinder Morgan Energy Partners' main transmission pipelines, and in certain cases, aggregate natural gas that must be processed or treated at its own or third-party facilities. Kinder Morgan Energy Partners owns two processing plants: the Texas City Plant in Galveston County, Texas and the Galveston Bay Plant in Chambers County, Texas, which is currently idle. Combined, these plants can process 115 million cubic feet per day of natural gas for liquids extraction. In addition, Kinder Morgan Energy Partners has contractual rights to process approximately 800 million cubic feet per day of natural gas at various third-party owned facilities. Kinder Morgan Energy Partners also owns and operates three natural gas treating plants that offer carbon dioxide and/or hydrogen sulfide removal. Kinder Morgan Energy Partners can treat up to 155 million cubic feet per day of natural gas for carbon dioxide removal at the Fandango Complex in Zapata County, Texas, 50 million cubic feet per day of natural gas at the Indian Rock Plant in Upshur County, Texas and approximately 45 million cubic feet per day of natural gas at the Thompsonville Facility located in Jim Hogg County, Texas.

The North Dayton natural gas storage facility, located in Liberty County, Texas, has two existing storage caverns providing approximately 6.3 billion cubic feet of total capacity, consisting of 4.2 billion cubic feet of working capacity and 2.1 billion cubic feet of pad gas. Kinder Morgan Energy Partners entered into a long-term storage capacity and transportation agreement with Texas Genco covering two billion cubic feet of natural gas working capacity that expires in March 2017.

In June 2006, Kinder Morgan Energy Partners announced an expansion project that will significantly increase natural gas storage capacity at the North Dayton facility. The project is expected to cost between \$76 million and \$82 million and involves the development of a new underground storage cavern that will add an estimated 5.5 billion cubic feet of incremental working natural gas storage capacity. The additional capacity is expected to be available in mid-2009.

Kinder Morgan Energy Partners also owns the West Clear Lake natural gas storage facility located in Harris County, Texas. Under a long term contract, Coral Energy Resources, L.P. operates the facility and controls the 96 billion cubic feet of natural gas working capacity, and Kinder Morgan Energy Partners provides transportation service into and out of the facility.

Additionally, Kinder Morgan Energy Partners leases a salt dome storage facility located near Markham, Texas, according to the provisions of an operating lease that expires in March 2013. Kinder Morgan Energy Partners can, at its sole option, extend the term of this lease for two additional ten-year periods. The facility currently consists of three salt dome caverns with approximately 10.0 billion cubic feet of working natural gas capacity and up to 750 million cubic feet per day of peak deliverability. A fourth cavern, with an additional 7.0 billion cubic feet of working natural gas capacity, is expected to be in service the second quarter of 2007. Kinder Morgan Energy Partners also leases two salt dome caverns, known as the Stratton Ridge Facilities, from BP America Production Company in Brazoria County, Texas. The Stratton Ridge Facilities have a combined working natural gas capacity of 1.4 billion cubic feet and a peak day deliverability of 100 million cubic feet per day. A lease with Dow Hydrocarbon & Resources, Inc. for a salt dome cavern containing approximately 5.0 billion cubic feet of working capacity expires during the third quarter of 2007, and we do not expect to extend the lease.

Markets. Texas is one of the largest natural gas consuming states in the country. The natural gas demand profile in Kinder Morgan Energy Partners' Texas intrastate pipeline group's market area is primarily composed of industrial (including on-site cogeneration facilities), merchant and utility power and to a lesser extent local natural gas distribution consumption. The industrial demand is primarily year-round load. Merchant and utility power demand peaks in the summer months and is complemented by local natural gas distribution demand that peaks in the winter months. As new merchant gas fired generation has come online and displaced traditional utility generation, Kinder Morgan Energy Partners has successfully attached many of these new generation facilities to its pipeline systems in order to maintain and grow its share of natural gas supply for power generation. Additionally, in 2007, Kinder Morgan Energy Partners has increased its capability and commitment to serve the growing local natural gas distribution market in the greater Houston metropolitan area.

Kinder Morgan Energy Partners serves the Mexico market through interconnection with the facilities of Pemex at the United States-Mexico border near Arguellas, Mexico and Monterrey, Mexico. In 2006, deliveries through the existing interconnection near Arguellas fluctuated from zero to approximately 218 million cubic feet per day of natural gas, and there were several days of exports to the United States which ranged up to 202 million cubic feet per day. Deliveries to Monterrey also ranged from zero to 322 million cubic feet per day. Kinder Morgan Energy Partners primarily provides transport service to these markets on a fee for service basis, including a significant demand component, which is paid regardless of actual throughput. Revenues earned from Kinder Morgan Energy Partners' activities in Mexico are paid in U.S. dollar equivalent.

Supply. Kinder Morgan Energy Partners purchases its natural gas directly from producers attached to its system in South Texas, East Texas and along the Texas Gulf Coast. Kinder Morgan Energy Partners also purchases gas at interconnects with third-party interstate and intrastate pipelines. While the intrastate group does not produce gas, it does maintain an active well connection program in order to offset natural declines in production along its system and to secure supplies for additional demand in its market area. The intrastate system has access to both onshore and offshore sources of supply, and is well positioned to interconnect with liquefied natural gas projects currently under development by others along the Texas Gulf Coast.

Competition. The Texas intrastate natural gas market is highly competitive, with many markets connected to multiple pipeline companies. Kinder Morgan Energy Partners competes with interstate and intrastate pipelines, and their shippers, for attachments to new markets and supplies and for transportation, processing and treating services.

Kinder Morgan Interstate Gas Transmission LLC

Kinder Morgan Interstate Gas Transmission LLC, referred to in this report as KMIGT, along with Trailblazer Pipeline Company, TransColorado Gas Transmission Company, and a current 51% ownership interest in the Rockies Express Pipeline (all discussed following) comprise Kinder Morgan Energy Partners' four Rocky Mountain interstate natural gas pipeline systems.

KMIGT owns approximately 5,100 miles of transmission lines in Wyoming, Colorado, Kansas, Missouri and Nebraska. The pipeline system is powered by 28 transmission and storage compressor stations with approximately 160,000 horsepower. KMIGT also owns the Huntsman natural gas storage facility, located in Cheyenne County, Nebraska, which has approximately 10 billion cubic feet of firm capacity commitments and provides for withdrawal of up to 169 million cubic feet of natural gas per day.

Under transportation agreements and FERC tariff provisions, KMIGT offers its customers firm and interruptible transportation and storage services, including no-notice park and loan services. For these services, KMIGT charges rates that include the retention of fuel and gas lost and unaccounted for in-kind. Under KMIGT's tariffs, firm transportation and storage customers pay reservation fees each month plus a commodity charge based on the actual transported or stored volumes. In contrast, interruptible transportation and storage customers pay a commodity charge based upon actual transported and/or stored volumes. Under the no-notice service, customers pay a fee for the right to use a combination of firm storage and firm transportation to effect deliveries of natural gas up to a specified volume without making specific nominations. KMIGT also has the authority to make gas purchases and sales, as needed for system operations, pursuant to its currently effective FERC gas tariff.

KMIGT also offers its Cheyenne Market Center service, which provides nominated storage and transportation service between its Huntsman storage field and multiple interconnecting pipelines at the Cheyenne Hub, located in Weld County, Colorado. This service is fully subscribed through May 2014.

Markets. Markets served by KMIGT provide a stable customer base with expansion opportunities due to the system's access to growing Rocky Mountain supply sources. Markets served by KMIGT are comprised mainly of local natural gas distribution companies and interconnecting interstate pipelines in the mid-continent area. End-users of the local natural gas distribution companies typically include residential, commercial, industrial and agricultural customers. The pipelines interconnecting with KMIGT in turn deliver gas into multiple markets including some of the largest population centers in the Midwest. Natural gas demand to power pumps for crop irrigation during the summer from time-to-time exceeds heating season demand and provides KMIGT relatively consistent volumes throughout the year. In addition, KMIGT has seen a significant increase in demand from ethanol producers, and is actively seeking ways to meet the demands from the ethanol producing community.

Supply. Approximately 5%, by volume, of KMIGT's firm contracts expire within one year and 61% expire within one to five years. Over 99% of the system's total firm transport capacity is currently subscribed, and affiliates are responsible for approximately 30% of the total contracted firm transportation and storage capacity on KMIGT's system. The majority of this affiliated business is dedicated to our U.S. retail natural gas distribution operations, and in August 2006, we entered into a definitive agreement with a subsidiary of General Electric Company to sell our U.S. retail natural gas distribution and related operations. Pending regulatory approvals, we expect this transaction to close by the end of the first quarter of 2007.

Competition. KMIGT competes with other interstate and intrastate gas pipelines transporting gas from the supply sources in the Rocky Mountain and Hugoton Basins to mid-continent pipelines and market centers.

Trailblazer Pipeline Company

The Trailblazer Pipeline Company owns a 436-mile natural gas pipeline system that originates at an interconnection with Wyoming Interstate Company Ltd.'s pipeline system near Rockport, Colorado and runs through southeastern Wyoming to a terminus near Beatrice, Nebraska where it interconnects with NGPL's and Northern Natural Gas Company's pipeline systems. NGPL manages, maintains and operates Trailblazer, for which it is reimbursed at cost.

Trailblazer's pipeline is the fourth and last segment of a 791-mile pipeline system known as the Trailblazer Pipeline System, which originates in Uinta County, Wyoming with Canyon Creek Compression Company, a 22,000 horsepower compressor station located at the tailgate of BP's processing plant in the Whitney Canyon Area in Wyoming (Canyon Creek's facilities are the first segment). Canyon Creek receives gas from the BP processing plant and provides transportation and compression of gas for delivery to Overthrust Pipeline Company's 88-mile, 36-inch diameter pipeline system at an interconnection in Uinta County, Wyoming (Overthrust's system is the second segment). Overthrust delivers gas to Wyoming Interstate's 269-mile, 36-inch diameter pipeline system at an inter-connection (Kanda) in Sweetwater County, Wyoming (Wyoming Interstate's system is the third segment). Wyoming Interstate's pipeline delivers gas to Trailblazer's pipeline at an interconnection near Rockport in Weld County, Colorado.

Trailblazer provides transportation services to third-party natural gas producers, marketers, local distribution companies and other shippers. Pursuant to transportation agreements and FERC tariff provisions, Trailblazer offers its customers firm and interruptible transportation. Under Trailblazer's tariffs, firm transportation customers pay reservation charges each month plus a commodity charge based on actual volumes transported. Interruptible transportation customers pay a commodity charge based upon actual volumes transported.

Markets. Significant growth in Rocky Mountain natural gas supplies has prompted a need for additional pipeline transportation service. Trailblazer has a certificated capacity of 846 million cubic feet per day of natural gas.

Supply. As of December 31, 2006, approximately 16% of Trailblazer's firm contracts, by volume, expire before one year and 19%, by volume, expire within one to five years. Affiliated entities hold less than 1% of the total firm transportation capacity. All of the system's firm transport capacity is currently subscribed.

Competition. The main competition that Trailblazer currently faces is that the gas supply in the Rocky Mountain area either stays in the area or is moved west and therefore is not transported on Trailblazer's pipeline. In addition, El Paso's Cheyenne Plains Pipeline can transport approximately 730 million cubic feet per day of natural gas from Weld County, Colorado to Greensburg, Kansas and competes with Trailblazer for natural gas pipeline transportation demand from the Rocky Mountain area. Additional competition could come from proposed pipeline projects such as the Rockies Express Pipeline. No assurance can be given that additional competing pipelines will not be developed in the future.

TransColorado Gas Transmission Company

The TransColorado Gas Transmission Company owns a 300-mile interstate natural gas pipeline that extends from approximately 20 miles southwest of Meeker, Colorado to Bloomfield, New Mexico. It has multiple points of interconnection with various interstate and intrastate pipelines, gathering systems, and local distribution companies. The pipeline system is powered by six compressor stations having an aggregate of approximately 30,000 horsepower. Kinder Morgan, Inc. manages, maintains and operates TransColorado, for which it is reimbursed at cost.

TransColorado has the ability to flow gas south or north. TransColorado receives gas from one coal seam natural gas treating plant located in the San Juan Basin of Colorado and from pipeline, processing plant and gathering system interconnections within the Paradox and Piceance Basins of western Colorado. Gas flowing south through the pipeline moves onto the El Paso, Transwestern and Questar Southern Trail pipeline systems. Gas moving north flows into the Colorado Interstate, Wyoming Interstate and Questar Pipeline systems at the Greasewood Hub and the Rockies Express Pipeline at the Meeker Hub. TransColorado provides transportation services to third-party natural gas producers, marketers, gathering companies, local distribution companies and other shippers.

Pursuant to transportation agreements and FERC tariff provisions, TransColorado offers its customers firm and interruptible transportation and interruptible park and loan services. For these services, TransColorado charges rates that include the retention of fuel and gas lost and unaccounted for in-kind. Under TransColorado's tariffs, firm transportation customers pay reservation charges each month plus a commodity charge based on actual volumes transported. Interruptible transportation customers pay a commodity charge based upon actual volumes transported. The underlying reservation and commodity charges are assessed pursuant to a maximum recourse rate structure, which does not vary based on the distance gas is transported. TransColorado has the authority to negotiate rates with customers if it has first offered service to those customers under its reservation and commodity charge rate structure.

On June 23, 2006, in FERC Docket No. CP06-401-000, TransColorado filed an application for authorization to construct and operate certain facilities comprising its Blanco-Meeker Expansion Project. Upon approval, this project will facilitate additional market access to Rocky Mountain gas production by transporting up to 250 million cubic feet per day of natural gas from the Blanco Hub area in San Juan County, New Mexico through TransColorado's existing facilities for deliveries to the Rockies Express Pipeline at an existing point of interconnection located at the Meeker Hub in Rio Blanco County, Colorado. A prearranged shipper has executed a binding precedent agreement for all capacity on the project. The total expansion project is expected to cost approximately $58 million.

Markets. TransColorado acts principally as a feeder pipeline system from the developing natural gas supply basins on the Western Slope of Colorado into the interstate natural gas pipelines that lead away from the Blanco Hub area of New Mexico and the interstate natural gas pipelines that lead away eastward from northwestern Colorado and southwestern Wyoming. TransColorado is the largest transporter of natural gas from the Western Slope supply basins of Colorado and provides a competitively attractive outlet for that developing natural gas resource. In 2006, TransColorado transported an average of approximately 869 million cubic feet per day of natural gas from these supply basins, an increase of 30% over the previous year. The increase in transportation deliveries was partially due to the completion of TransColorado's north system expansion project, which was placed in-service on January 1, 2006. The expansion provided for up to 300 million cubic feet per day of additional northbound transportation capacity, and was supported by a long-term contract with Williams Companies, Inc. that runs through 2015, with an option for a five-year extension.

Supply. During 2006, 83% of TransColorado's transport business was with producers or their own marketing affiliates and 15% was with gathering companies, and the remaining 2% was with various gas marketers. Approximately 70% of TransColorado's transport business in 2006 was conducted with its two largest customers. All of TransColorado's southbound pipeline capacity is committed under firm transportation contracts that extend at least through year-end 2007. TransColorado's pipeline capacity is 93% subscribed during 2007 through 2011 and TransColorado is actively pursuing contract extensions and or replacement contracts to increase firm subscription levels beyond 2007.

Competition. TransColorado competes with other transporters of natural gas in each of the natural gas supply basins it serves. These competitors include both interstate and intrastate natural gas pipelines and natural gas gathering systems. TransColorado's shippers compete for market share with shippers drawing upon gas production facilities within the New Mexico portion of the San Juan Basin. TransColorado has phased its past construction and expansion efforts to coincide with the ability of the interstate pipeline grid at Blanco, New Mexico to accommodate greater natural gas volumes. TransColorado's transport concurrently ramped up over that period such that TransColorado now enjoys a growing share of the outlet from the San Juan Basin to the southwestern United States marketplace.

Historically, the competition faced by TransColorado with respect to its natural gas transportation services has generally been based upon the price differential between the San Juan and Rocky Mountain basins. Competing pipelines servicing these producing basins have had the effect of reducing that price differential; however, given the increased number of direct connections to production facilities in the Piceance and Paradox basins and the gas supply development in each of those basins, we believe that TransColorado's transport business will be less susceptible to changes in the price differential in the future.

Rockies Express Pipeline

Kinder Morgan Energy Partners operates and currently owns 51% of the 1,662-mile Rockies Express Pipeline system, which when fully completed, will be one of the largest natural gas pipelines ever constructed in North America. The approximately $4.4 billion project will have the capability to transport 1.8 billion cubic feet per day of natural gas, and binding firm commitments have been secured for virtually all of the pipeline capacity. The pipeline is owned by Rockies Express Pipeline LLC, a wholly-owned subsidiary of West2East Pipeline LLC, and as of December 31, 2006, Kinder Morgan Energy Partners owned 51%, Sempra Energy held a 25% ownership interest and ConocoPhillips owned the remaining 24% ownership interest. When construction of the entire project is completed, Kinder Morgan Energy Partners' ownership interest will be reduced to 50% and the capital accounts of West2East Pipeline LLC will be trued up to reflect Kinder Morgan Energy Partners' 50% economics in the project. We do not anticipate any additional changes in the ownership structure of the project.

The first part of the Rockies Express Pipeline is referred to in this report as Rockies Express-Entrega, and consists of a 327-mile section that runs from the Meeker Hub in northwest Colorado, across southern Wyoming to the Cheyenne Hub in Weld County, Colorado. The first 136-miles of 36-inch diameter pipeline from the Meeker Hub to the Wamsutter Hub in Sweetwater County, Wyoming, provided interim service in 2006 during the construction and completion of the second pipeline segment, a 191-mile, 42-inch diameter line extending from the Wamsutter Hub to the Cheyenne Hub. The completed construction of the second segment from the Wamsutter Hub to the Cheyenne Hub on February 14, 2007, signified the completion of phase one of the total Rockies Express – Entrega project.

On May 31, 2006, Rockies Express Pipeline LLC filed an application with the FERC for authorization to construct and operate certain facilities comprising its proposed Rockies Express-West project. This project is the first planned segment extension of Rockies Express-Entrega, described above. The Rockies Express-West project will be comprised of approximately 713 miles of 42-inch diameter pipeline extending from the Cheyenne Hub to an interconnection with Panhandle Eastern Pipe Line located in Audrain County, Missouri. The segment extension proposes to transport approximately 1.5 billion cubic feet per day of natural gas across the following five states: Wyoming, Colorado, Nebraska, Kansas and Missouri. The project will also include certain improvements to existing Rockies Express facilities located to the west of the Cheyenne Hub. On September 21, 2006, the FERC made a preliminary determination that the issuance of a certificate to Rockies Express under the provisions of the Natural Gas Act to construct and operate the Rockies Express-West Project, and enter into a lease with Questar Overthrust Pipeline Company, would on the basis of all non-environmental issues be required by the public convenience and necessity. On December 27, 2006, Rockies Express and TransColorado filed their joint responses to the FERC's Draft Environmental Impact Statement. Rockies Express expects to receive final FERC approval in March 2007, and plans to begin construction in May 2007, with a targeted in-service date of January 1, 2008.

The final segment of the Rockies Express Pipeline, referred to as Rockies Express-East, consists of an approximate 635-mile pipeline segment that will extend from eastern Missouri to the Clarington Hub in eastern Ohio. Rockies Express will file a separate application in the future for this proposed Rockies Express-East project. In June 2006, Kinder Morgan Energy Partners made the National Environmental Policy Act pre-filing for Rockies Express-East with the FERC. From September 11-15, 2006, the FERC hosted nine scoping meetings for the preparation of an Environmental Impact Statement along the proposed route. Rockies Express-East is expected to begin interim service as early as December 31, 2008, and to be fully completed by June 2009.

Kinder Morgan Louisiana Pipeline

In September 2006, Kinder Morgan Energy Partners filed an application with the FERC requesting approval to construct and operate the Kinder Morgan Louisiana Pipeline. The natural gas pipeline project is expected to cost approximately $500 million and will provide approximately 3.2 billion cubic feet per day of take-away natural gas capacity from the Cheniere Sabine Pass liquefied natural gas terminal located in Cameron Parish, Louisiana. The project is supported by fully subscribed capacity and long-term customer commitments with Chevron and Total, and in exchange for shipper commitments to the project, Kinder Morgan Energy Partners has granted options to acquire equity in the project, which, if fully exercised, could result in Kinder Morgan Energy Partners owning a minimum interest of 80% after the project is completed.

The Kinder Morgan Louisiana Pipeline will consist of two segments:

- a 132-mile, 42-inch diameter pipeline with firm capacity of approximately 2.0 billion cubic feet per day of natural gas that will extend from the Sabine Pass terminal to a point of interconnection with an existing Columbia Gulf Transmission line in Evangeline Parish, Louisiana (an offshoot will consist of approximately 2.3 miles of 24-inch diameter pipeline with firm peak day capacity of approximately 300 million cubic feet per day extending away from the 42-inch diameter line to the existing Florida Gas Transmission Company compressor station in Acadia Parish, Louisiana). This segment is expected to be in service in the second quarter of 2009; and

- a 1-mile, 36-inch diameter pipeline with firm capacity of approximately 1.2 billion cubic feet per day that will extend from the Sabine Pass terminal and connect to NGPL's natural gas pipeline. This portion of the project is expected to be in service in the third quarter of 2008.

Kinder Morgan Energy Partners has designed and will construct the Kinder Morgan Louisiana Pipeline in a manner that will minimize environmental impacts, and where possible, existing pipeline corridors will be used to minimize impacts to communities and to the environment. As of December 31, 2006, there were no major pipeline re-routes as a result of any landowner requests. Kinder Morgan Energy Partners is currently finalizing pipeline interconnect agreements, preparing detailed designs of the facilities, attending FERC inter-agency meetings and acquiring pipeline right-of-way.

Casper and Douglas Natural Gas Gathering and Processing Systems

Kinder Morgan Energy Partners owns and operates the Casper, Wyoming natural gas processing plant, which is a lean oil absorption facility with full fractionation and has capacity to process up to 70 million cubic feet per day of natural gas depending on raw gas quality. The inlet composition of gas entering the Casper plant averages approximately 1.5 gallons per thousand cubic feet of propane and heavier natural gas liquids, reflecting the relatively lean gas gathered and delivered to the Casper plant.

Kinder Morgan Energy Partners also owns and operates the Douglas natural gas processing facility, located in Douglas, Wyoming. The Douglas plant is capable of processing approximately 115 million cubic feet of natural gas per day. The plant is a cryogenic facility which recovers the full range of natural gas liquids from ethane through natural gasoline. The plant also has a stabilizer capable of capturing heavy end natural gas liquids for sale into local markets at a premium price. Residue gas is delivered from the plant into KMIGT and recovered liquids are injected in ConocoPhillips Petroleum's natural gas liquids pipeline for transport to Borger, Texas.

Effective April 1, 2006, Kinder Morgan Energy Partners sold its Wyoming natural gas gathering system and its Painter Unit fractionation facility to a third party for approximately $42.5 million in cash. For more information on this sale, see Note 5 to our consolidated financial statements included elsewhere in this report.

Markets. Casper and Douglas are processing plants servicing gas streams flowing into KMIGT. Natural gas liquids processed by the Casper plant are sold into local markets consisting primarily of retail propane dealers, oil refiners, and ethanol production facilities. Natural gas liquids processed by the Douglas plant are sold to ConocoPhillips via their Powder River natural gas liquids pipeline for either ultimate consumption at the Borger refinery or for further disposition to the natural gas liquids trading hubs located in Conway, Kansas and Mont Belvieu, Texas.

Competition. Other regional facilities in the Greater Powder River Basin include the Hilight plant (80 million cubic feet per day) owned and operated by Anadarko, the Sage Creek plant (50 million cubic feet per day) owned and operated by Merit Energy, and the Rawlins plant (50 million cubic feet per day) owned and operated by El Paso. Casper and Douglas, however, are the only plants which provide straddle processing of natural gas flowing into KMIGT.

Red Cedar Gathering Company

Kinder Morgan Energy Partners owns a 49% equity interest in the Red Cedar Gathering Company, a joint venture organized in August 1994 and referred to in this report as Red Cedar. The remaining 51% interest in Red Cedar is owned by the Southern Ute Indian Tribe. Red Cedar owns and operates natural gas gathering, compression and treating facilities in the Ignacio Blanco Field in La Plata County, Colorado. The Ignacio Blanco Field lies within the Colorado portion of the San Juan Basin, most of which is located within the exterior boundaries of the Southern Ute Indian Tribe Reservation. Red Cedar gathers coal seam and conventional natural gas at wellheads and several central delivery points, for treating, compression and delivery into any one of four major interstate natural gas pipeline systems and an intrastate pipeline.

Red Cedar also owns Coyote Gas Treating, LLC, referred to in this report as Coyote Gulch. Previously, Kinder Morgan Energy Partners owned a 50% equity interest in Coyote Gulch and Enterprise Field Services LLC owned the remaining 50%. Effective March 1, 2006, the Southern Ute Indian Tribe acquired Enterprise's 50% interest in Coyote Gulch. Kinder Morgan Energy Partners and the Tribe agreed to a resolution that would transfer all of the members' equity in Coyote Gulch to the members' equity of Red Cedar, and effective September 1, 2006, Coyote Gulch was a wholly owned subsidiary of Red Cedar.

The sole asset owned by Coyote Gulch is a 250 million cubic feet per day natural gas treating facility located in La Plata County, Colorado. The inlet gas stream treated by Coyote Gulch contains an average carbon dioxide content of between 12% and 13%. The plant treats the gas down to a carbon dioxide concentration of 2% in order to meet interstate natural gas pipeline quality specifications, and then compresses the natural gas into the TransColorado Gas Transmission pipeline for transport to the Blanco, New Mexico-San Juan Basin Hub.

Red Cedar's gas gathering system currently consists of over 1,100 miles of gathering pipeline connecting more than 920 producing wells, 85,000 horsepower of compression at 24 field compressor stations and two carbon dioxide treating plants. A majority of the natural gas on the system moves through 8-inch to 16-inch diameter pipe. The capacity and throughput of the Red Cedar system as currently configured is approximately 750 million cubic feet per day of natural gas.

Thunder Creek Gas Services, LLC

Kinder Morgan Energy Partners owns a 25% equity interest in Thunder Creek Gas Services, LLC, referred to in this report as Thunder Creek. Devon Energy owns the remaining 75%. Thunder Creek provides gathering, compression and treating services to a number of coal seam gas producers in the Powder River Basin of Wyoming. Throughput volumes include both coal seam and conventional plant residue gas. Thunder Creek is independently operated from offices located in Denver, Colorado with field offices in Glenrock and Gillette, Wyoming.

Thunder Creek's operations are a combination of mainline and low pressure gathering assets. The mainline assets include 125 miles of 24-inch diameter mainline pipeline, 230 miles of 4-inch to 12-inch diameter high and low pressure laterals, 24,265 horsepower of mainline compression and carbon dioxide removal facilities consisting of a 240 million cubic feet per day carbon dioxide treating plant complete with dehydration. The mainline assets receive gas from 52 receipt points and can deliver treated gas to seven delivery points including Colorado Interstate Gas, Wyoming Interstate Gas Company, KMIGT and three power plants. The low pressure gathering assets include five systems consisting of 194 miles of 4-inch to 14-inch diameter gathering pipeline and 35,400 horsepower of field compression. Gas is gathered from 101 receipt points and delivered to the mainline at seven primary locations.

CO_2 – KMP

The CO_2 – KMP segment consists of Kinder Morgan CO_2 Company, L.P. and its consolidated affiliates, referred to in this report as $KMCO_2$. Carbon dioxide is used in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. $KMCO_2$'s carbon dioxide pipelines and related assets allow Kinder Morgan Energy Partners to market a complete package of carbon dioxide supply, transportation and technical expertise to the customer. Together, the CO_2 – KMP business segment produces, transports and markets carbon dioxide for use in enhanced oil recovery operations. Kinder

Morgan Energy Partners also holds ownership interests in several oil-producing fields and owns a 450-mile crude oil pipeline, all located in the Permian Basin region of West Texas.

Carbon Dioxide Reserves

Kinder Morgan Energy Partners owns approximately 45% of, and operates, the McElmo Dome unit, which contains more than nine trillion cubic feet of recoverable carbon dioxide. Deliverability and compression capacity exceeds one billion cubic feet per day. The McElmo Dome unit is located in Montezuma County, Colorado and produces from the Leadville formation at approximately 8,000 feet with 54 wells that combined, produced an average of 973 million cubic feet per day in 2006. Kinder Morgan Energy Partners also owns approximately 11% of the Bravo Dome unit, which contains reserves of approximately two trillion cubic feet of recoverable carbon dioxide. Located in the northeast quadrant of New Mexico, the Bravo Dome unit produces approximately 290 million cubic feet per day, with production coming from more than 350 wells in the Tubb Sandstone at 2,300 feet.

Kinder Morgan Energy Partners also owns approximately 88% of the Doe Canyon Deep unit, which contains more than 1.5 trillion cubic feet of carbon dioxide. Kinder Morgan Energy Partners is currently installing facilities and six wells to produce an average of 100 million cubic feet per day of carbon dioxide beginning in January 2008. The Doe Canyon Deep unit is located in Delores County, Colorado, and it will produce from the Leadville formation at approximately 8,800 feet.

Markets. Kinder Morgan Energy Partners' principal market for carbon dioxide is for injection into mature oil fields in the Permian Basin, where industry demand is expected to grow modestly for the next several years. Kinder Morgan Energy Partners is exploring additional potential markets, including enhanced oil recovery targets in California, Wyoming, the Gulf Coast, Mexico, and Canada, and coal bed methane production in the San Juan Basin of New Mexico.

Competition. Kinder Morgan Energy Partners' primary competitors for the sale of carbon dioxide include suppliers that have an ownership interest in McElmo Dome, Bravo Dome and Sheep Mountain carbon dioxide reserves, and Petro-Source Carbon Company, which gathers waste carbon dioxide from natural gas production in the Val Verde Basin of West Texas. There is no assurance that new carbon dioxide sources will not be discovered or developed, which could compete with Kinder Morgan Energy Partners or that new methodologies for enhanced oil recovery will not replace carbon dioxide flooding.

Carbon Dioxide Pipelines

As a result of its 50% ownership interest in Cortez Pipeline Company, Kinder Morgan Energy Partners owns a 50% equity interest in and operates the approximate 500-mile, 30-inch diameter Cortez pipeline. The pipeline carries carbon dioxide from the McElmo Dome source reservoir in Cortez, Colorado to the Denver City, Texas hub. The Cortez pipeline currently transports nearly one billion cubic feet of carbon dioxide per day, including approximately 99% of the carbon dioxide transported downstream on the Central Basin pipeline and the Centerline pipeline, both described following.

Kinder Morgan Energy Partners' Central Basin pipeline consists of approximately 143 miles of 16-inch to 26-inch diameter pipe and 177 miles of 4-inch to 12-inch diameter lateral supply lines located in the Permian Basin between Denver City, Texas and McCamey, Texas, with a throughput capacity of 600 million cubic feet per day. At its origination point in Denver City, the Central Basin pipeline interconnects with all three major carbon dioxide supply pipelines from Colorado and New Mexico, namely the Cortez pipeline (operated by $KMCO_2$) and the Bravo and Sheep Mountain pipelines (operated by Occidental and Trinity CO_2, respectively). Central Basin's mainline terminates near McCamey where it interconnects with the Canyon Reef Carriers pipeline and the Pecos pipeline. The tariffs charged by the Central Basin pipeline are not regulated.

Kinder Morgan Energy Partners' Centerline pipeline consists of approximately 113 miles of 16-inch diameter pipe located in the Permian Basin between Denver City, Texas and Snyder, Texas. The pipeline has a capacity of 300 million cubic feet per day. The tariffs charged by the Centerline pipeline are not regulated.

Kinder Morgan Energy Partners owns a 13% undivided interest in the 218-mile, 20-inch diameter Bravo pipeline, which delivers to the Denver City hub and has a capacity of more than 350 million cubic feet per day. Major delivery points along the line include the Slaughter field in Cochran and Hockley Counties, Texas, and the Wasson field in Yoakum County, Texas. Tariffs on the Cortez and Bravo pipelines are not regulated.

In addition, Kinder Morgan Energy Partners owns approximately 98% of the Canyon Reef Carriers pipeline and approximately 69% of the Pecos pipeline. The Canyon Reef Carriers pipeline extends 139 miles from McCamey, Texas, to the SACROC unit. The pipeline has a 16-inch diameter, a capacity of approximately 290 million cubic feet per day and makes deliveries to the SACROC, Sharon Ridge, Cogdell and Reinecke units. The Pecos pipeline is a 25-mile, 8-inch diameter pipeline that runs from McCamey to Iraan, Texas. It has a capacity of approximately 120 million cubic feet per day of carbon dioxide and makes deliveries to the Yates unit. The tariffs charged on the Canyon Reef Carriers and Pecos pipelines are not regulated.

Markets. The principal market for transportation on $KMCO_2$'s carbon dioxide pipelines is to customers, including Kinder Morgan Energy Partners, using carbon dioxide for enhanced recovery operations in mature oil fields in the Permian Basin, where industry demand is expected to grow modestly for the next several years.

Competition. Kinder Morgan Energy Partners' ownership interests in the Central Basin, Cortez and Bravo pipelines are in direct competition with other carbon dioxide pipelines. Kinder Morgan Energy Partners also competes with other interest owners in McElmo Dome and Bravo Dome for transportation of carbon dioxide to the Denver City, Texas market area.

Oil Reserves

$KMCO_2$ also holds ownership interests in oil-producing fields, including an approximate 97% working interest in the SACROC unit, an approximate 50% working interest in the Yates unit, a 21% net profits interest in the H.T. Boyd unit, an approximate 65% working interest in the Claytonville unit, an approximate 95% working interest in the Katz CB Long unit, an approximate 64% working interest in the Katz SW River unit, a 100% working interest in the Katz East River unit, and lesser interests in the Sharon Ridge unit, the Reinecke unit and the MidCross unit, all of which are located in the Permian Basin of West Texas.

The SACROC unit is one of the largest and oldest oil fields in the United States using carbon dioxide flooding technology. The field is comprised of approximately 56,000 acres located in the Permian Basin in Scurry County, Texas. SACROC was discovered in 1948 and has produced over 1.29 billion barrels of oil since inception. It is estimated that SACROC originally held approximately 2.7 billion barrels of oil. We have expanded the development of the carbon dioxide project initiated by the previous owners and increased production over the last several years. The Yates unit is also one of the largest oil fields ever discovered in the United States. It is estimated that it originally held more than five billion barrels of oil, of which about 28% has been produced. The field, discovered in 1926, is comprised of approximately 26,000 acres located about 90 miles south of Midland, Texas.

As of December 2006, the SACROC unit had 355 producing wells, and the purchased carbon dioxide injection rate was 247 million cubic feet per day, down from an average of 258 million cubic feet per day as of December 2005. The average oil production rate for 2006 was approximately 30,800 barrels of oil per day, down from an average of approximately 32,400 barrels of oil per day during 2005. The average natural gas liquids production rate (net of the processing plant share) for 2006 was approximately 5,700 barrels per day, down from an average of approximately 6,000 barrels per day during 2005.

Kinder Morgan Energy Partners' plan has been to increase the production rate and ultimate oil recovery from Yates by combining horizontal drilling with carbon dioxide injection to ensure a relatively steady production profile over the next several years. Kinder Morgan Energy Partners is implementing its plan and as of December 2006, the Yates unit was producing about 27,000 barrels of oil per day. As of December 2005, the Yates unit was producing approximately 24,000 barrels of oil per day. Unlike operations at SACROC, where carbon dioxide and water is used to drive oil to the producing wells, Kinder Morgan Energy Partners is using carbon dioxide injection to replace nitrogen injection at Yates in order to enhance the gravity drainage process, as well as to maintain reservoir pressure. The differences in geology and reservoir mechanics between the two fields mean that substantially less capital will be needed to develop the reserves at Yates than is required at SACROC.

Kinder Morgan Energy Partners also operates and owns an approximate 64.5% gross working interest in the Claytonville oil field unit located in Fisher County, Texas. The Claytonville unit is located nearly 30 miles east of the SACROC unit in the Permian Basin of West Texas and is currently producing approximately 200 barrels of oil per day. Kinder Morgan Energy Partners is presently evaluating operating and subsurface technical data from the Claytonville unit to further assess redevelopment opportunities including carbon dioxide flood operations.

On April 5, 2006, Kinder Morgan Energy Partners purchased various oil and gas properties from Journey Acquisition – I, L.P. and Journey 2000, L.P. for an aggregate consideration of approximately $63.9 million, consisting of $60.3 million in cash and $3.6 million in assumed liabilities. The acquisition was effective March 1, 2006. However, since the acquisition, Kinder Morgan Energy Partners divested certain acquired properties that were not considered candidates for carbon dioxide enhanced oil recovery, and received proceeds of approximately $27.1 million from the sale of these properties. The retained properties, referred to in this report as the Katz field, are the Katz CB Long unit, the Katz Southwest River unit and Katz East River unit. The Katz field is primarily located in the Permian Basin area of West Texas and New Mexico and, as of December 2006, was producing approximately 430 barrels of oil equivalent per day. Kinder Morgan Energy Partners is presently evaluating operating and subsurface technical data to further assess redevelopment opportunities for the Katz field including the potential for carbon dioxide flood operations.

Oil Acreage and Wells

The following table sets forth productive wells, service wells and drilling wells in the oil and gas fields in which Kinder Morgan Energy Partners owns interests as of December 31, 2006. When used with respect to acres or wells, gross refers to the total acres or wells in which Kinder Morgan Energy Partners has a working interest; net refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by Kinder Morgan Energy Partners:

	Productive Wells[a]		**Service Wells**[b]		**Drilling Wells**[c]	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	2,604	1,590	1,078	766	2	2
Natural Gas	8	4	28	14	–	–
Total Wells	2,612	1,594	1,106	780	2	2

[a] Includes active wells and wells temporarily shut-in. As of December 31, 2006, Kinder Morgan Energy Partners did not operate any gross wells with multiple completions.

[b] Consists of injection, water supply, disposal wells and service wells temporarily shut-in. A disposal well is used for disposal of saltwater into an underground formation; a service well is a well drilled in a known oil field in order to inject liquids that enhance recovery or dispose of salt water.

[c] Consists of development wells in the process of being drilled as of December 31, 2006. A development well is a well drilled in an already discovered oil field.

The oil and gas producing fields in which Kinder Morgan Energy Partners owns interests are located in the Permian Basin area of West Texas and New Mexico. The following table reflects Kinder Morgan Energy Partners' net productive and dry wells that were completed in each of the three years ended December 31, 2006, 2005 and 2004:

	2006	**2005**	**2004**
Productive			
Development	37	42	31
Exploratory	–	–	–
Dry			
Development	–	–	–
Exploratory	–	–	–
Total Wells	37	42	31

Notes: The above table includes wells that were completed during each year regardless of the year in which drilling was initiated, and does not include any wells where drilling operations were not completed as of the end of the applicable year. Development wells include wells drilled in the proved area of an oil or gas resevoir.

The following table reflects the developed and undeveloped oil and gas acreage that Kinder Morgan Energy Partners held as of December 31, 2006:

	Gross	**Net**
Developed Acres	72,435	67,709
Undeveloped Acres	8,788	8,131
Total	81,223	75,840

Operating Statistics

Operating statistics from Kinder Morgan Energy Partners' oil and gas producing activities for each of the years 2006, 2005 and 2004 are shown in the following table:

Results of Operations for Oil and Gas Producing Activities – Unit Prices and Costs

	Year Ended December 31,		
	2006	**2005**	**2004**
Consolidated Companies[a]			
Production Costs per Barrel of Oil Equivalent[b, c, d]	$ 13.30	$ 10.00	$ 9.71
Crude Oil Production (MBbl/d)	37.8	37.9	32.5
Natural Gas Liquids Production (MBbl/d)[d]	5.0	5.3	3.7
Natural Gas liquids Production from Gas Plants(MBbl/d)[e]	3.9	4.1	4.0
Total Natural Gas Liquids Production(MBbl/d)	8.9	9.4	7.7
Natural Gas Production (MMcf/d)[d, f]	1.3	3.7	4.4
Natural Gas Production from Gas Plants(MMcf/d)[e, f]	0.3	3.1	3.9
Total Natural Gas Production(MMcf/d)[f]	1.6	6.8	8.3
Average Sales Prices Including Hedge Gains/Losses:			
Crude Oil Price per Bbl[g]	$ 31.42	$ 27.36	$ 25.72
Natural Gas Liquids Price per Bbl[g]	$ 43.52	$ 38.79	$ 31.37
Natural Gas Price per Mcf[h]	$ 6.36	$ 5.84	$ 5.27
Total Natural Gas Liquids Price per Bbl[e]	$ 43.90	$ 38.98	$ 31.33
Total Natural Gas Price per Mcf[e]	$ 7.02	$ 5.80	$ 5.24
Average Sales Prices Excluding Hedge Gains/Losses:			
Crude Oil Price per Bbl[g]	$ 63.27	$ 54.45	$ 40.91
Natural Gas Liquids Price per Bbl[g]	$ 43.52	$ 38.79	$ 31.68
Natural Gas Price per Mcf[h]	$ 6.36	$ 5.84	$ 5.27

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[a] Amounts relate to Kinder Morgan CO2 Company, L.P. and its consolidated subsidiaries.

[b] Computed using production costs, excluding transportation costs, as defined by the Securities and Exchange Commisson. Natural gas volumes were converted to barrels of oil equivalent (BOE) using a conversion factor of six mcf of natural gas to one barrel of oil.

[c] Production costs include labor, repairs and maintenance, materials, supplies, fuel and power, property taxes, severance taxes, and general and administrative expenses directly related to oil and gas producing activities.

[d] Includes only production attributable to leasehold ownership.

[e] Includes production attributable to Kinder Morgan Energy Partners' ownership in processing plants and third party processing agreements.

[f] Excludes natural gas production used as fuel.

[g] Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.

[h] Natural gas sales were not hedged.

Gas Plant Interests

Kinder Morgan Energy Partners operates and owns an approximate 22% working interest plus an additional 26% net profits interest in the Snyder gasoline plant. Kinder Morgan Energy Partners also operates and owns a 51% ownership interest in the Diamond M gas plant and a 100% ownership interest in the North Snyder plant, all of which are located in the Permian Basin of West Texas. The Snyder gasoline plant processes gas produced from the SACROC unit and neighboring carbon dioxide projects, specifically the Sharon Ridge and Cogdell units, all of which are located in the Permian Basin area of West Texas. The Diamond M and the North Snyder plants contract with the Snyder plant to process gas. Production of natural gas liquids at the Snyder gasoline plant as of December 2006 was approximately 15,000 barrels per day, the same rate of production as of December 2005.

Crude Oil Pipeline

Kinder Morgan Energy Partners owns the Kinder Morgan Wink Pipeline, a 450-mile crude oil pipeline system consisting of three mainline sections, two gathering systems and numerous truck off-loading stations. The entire system is all located within the State of Texas, and the 20-inch diameter segment that runs from Wink to El Paso has a total capacity of 130,000 barrels of crude oil per day (with the use of a drag reducing agent). The pipeline allows Kinder Morgan Energy Partners to better manage crude oil deliveries from its oil field interests in West Texas, and Kinder Morgan Energy Partners has entered into a long-term throughput agreement with Western Refining Company, L.P. to transport crude oil into Western's 120,000 barrel per day refinery in El Paso. The 20-inch pipeline segment transported approximately 113,000 barrels of oil per day in 2006. The Kinder Morgan Wink Pipeline is regulated by both the FERC and the Texas Railroad Commission.

Terminals – KMP

The Terminals – KMP segment includes the operations of Kinder Morgan Energy Partners' petroleum, chemical and other liquids terminal facilities (other than those included in the Products Pipelines – KMP segment) as well as all of Kinder Morgan Energy Partners' coal, petroleum coke, steel and dry-bulk material services, including all transload, engineering, conveying and other in-plant services. Combined, the segment is composed of approximately 94 owned or operated liquids and bulk terminal facilities, and more than 60 rail transloading and materials handling facilities located throughout the United States. In 2006, the number of customers from whom the Terminals – KMP segment received more than $0.1 million of revenue was approximately 550.

Liquids Terminals

The liquids terminal operations primarily store refined petroleum products, petrochemicals, industrial chemicals and vegetable oil products in aboveground storage tanks and transfer products to and from pipelines, tank trucks, tank barges, and tank railcars. Combined, the liquids terminal facilities possess liquids storage capacity of approximately 43.5 million barrels, and in 2006, these terminals handled approximately 555.2 million barrels of petroleum, petrochemical and vegetable oil products. Major liquids terminal assets of this segment are described below.

The Houston, Texas terminal complex is located in Pasadena and Galena Park, Texas, along the Houston Ship Channel. Recognized as a distribution hub for Houston's refineries situated on or near the Houston Ship Channel, the Pasadena and Galena Park terminals are the western Gulf Coast refining community's central interchange point. The complex has approximately 19.6 million barrels of capacity and is connected via pipeline to 14 refineries, four petrochemical plants and ten major outbound pipelines. In addition, the facilities have four ship docks and seven barge docks for inbound and outbound movement of products. The terminals are served by the Union Pacific railroad.

In September 2006, Kinder Morgan Energy Partners announced major expansions at its Pasadena and Galena Park, Texas terminal facilities. The expansions will provide additional infrastructure to help meet the growing need for refined petroleum products storage capacity along the Gulf Coast. The investment of approximately $195 million includes the construction of the following: (i) new storage tanks at both the Pasadena and Galena Park terminals; (ii) an additional cross-channel pipeline to increase the connectivity between the two terminals; (iii) a new ship dock at Galena Park; and (iv) an additional loading bay at the fully automated truck loading rack located at the Pasadena terminal. The expansions are supported by long-term customer commitments and will result in approximately 3.4 million barrels of additional tank storage capacity at the two terminals. Construction began in October 2006, and all of the projects are expected to be completed by the spring of 2008.

Kinder Morgan Energy Partners owns three liquids facilities in the New York Harbor area: one in Carteret, New Jersey, one in Perth Amboy, New Jersey, and one on Staten Island, New York. The Carteret facility is located along the Arthur Kill River just south of New York City and has a capacity of approximately 7.5 million barrels of petroleum and petrochemical products. The Carteret facility has two ship docks and four barge docks. It is connected to the Colonial, Buckeye, Sun and Harbor pipeline systems, and the CSX and Norfolk Southern railroads service the facility. The Perth Amboy facility is also located along the Arthur Kill River and has a capacity of approximately 2.3 million barrels of petroleum and petrochemical products. Tank sizes range from 2,000 barrels to 300,000 barrels. The Perth Amboy terminal provides chemical and petroleum storage and handling, as well as dry-bulk handling of salt and aggregates. In addition to providing product movement via vessel, truck and rail, Perth Amboy has direct access to the Buckeye and Colonial pipelines. The facility has one ship dock and one barge dock, and is connected to the CSX and Norfolk Southern railroads.

In January 2006, Kinder Morgan Energy Partners announced the investment of approximately $45 million for the construction of new liquids storage tanks at Perth Amboy. The Perth Amboy expansion will involve the construction of nine new storage tanks with a capacity of 1.4 million barrels for gasoline, diesel and jet fuel service. The expansion was driven by continued strong demand for refined products in the Northeast, much of which is being met by imported fuel arriving via the New York Harbor. Due to inconsistencies in the soils underneath these tanks, we now estimate that the tank foundations will cost significantly more than our original budget, bringing the total investment to approximately $56 million and delaying the in-service date to the third quarter of 2007.

The two New Jersey facilities offer a viable alternative for moving petroleum products between the refineries and terminals throughout the New York Harbor and both are New York Mercantile Exchange delivery points for gasoline and heating oil. Both facilities are connected to the Intra Harbor Transfer Service, an operation that offers direct outbound pipeline connections that allow product to be moved from over 20 Harbor delivery points to destinations north and west of New York City.

Kinder Morgan Energy Partners also owns the Kinder Morgan Staten Island terminal on Staten Island, New York. The facility is bounded to the north and west by the Arthur Kill River and covers approximately 200 acres, of which 120 acres are used for site operations. The terminal has a storage capacity of approximately 3.0 million barrels for gasoline, diesel fuel and fuel oil. The facility also maintains and operates an above ground piping network to transfer petroleum products throughout the operating portion of the site, and Kinder Morgan Energy Partners is currently rebuilding ship and barge berths at the facility that will accommodate tanker vessels.

Kinder Morgan Energy Partners owns two liquids terminal facilities in the Chicago area: one facility is located in Argo, Illinois, approximately 14 miles southwest of downtown Chicago, and the other is located in the Port of Chicago along the Calumet River. The Argo facility is a large petroleum product and ethanol blending facility and a major break bulk facility for large chemical manufacturers and distributors. It has approximately 2.5 million barrels of capacity in tankage ranging from 50,000 gallons to 80,000 barrels. The Argo terminal is situated along the Chicago sanitary and ship channel, and has three barge docks. The facility is connected to TEPPCO and Westshore pipelines, and has a direct connection to Midway Airport. The Canadian National railroad services this facility. The Port of Chicago facility handles a wide variety of liquid chemicals with a working capacity of approximately 795,000 barrels in tanks ranging from 12,000 gallons to 55,000 barrels. The facility provides access to a full slate of transportation options, including a deep water barge/ship berth on Lake Calumet, and offers services including truck loading and off-loading, iso-container handling and drumming. There are two ship docks and four barge docks, and the facility is served by the Norfolk Southern railroad.

Two of Kinder Morgan Energy Partners' other largest liquids facilities are located in South Louisiana: the Port of New Orleans facility located in Harvey, Louisiana, and the St. Gabriel terminal, located near a major petrochemical complex in Geismar, Louisiana. The New Orleans facility handles a variety of liquids products such as chemicals, vegetable oils, animal fats, alcohols and oil field products. It has approximately 3.0 million barrels of tankage ranging in sizes from 17,000 gallons to 200,000 barrels. There are three ship docks and one barge dock, and the Union Pacific railroad provides rail service. The terminal can be accessed by vessel, barge, tank truck, or rail, and also provides ancillary services including drumming, packaging, warehousing, and cold storage services.

The St. Gabriel facility is located approximately 75 miles north of the New Orleans facility on the bank of the Mississippi River near the town of St. Gabriel, Louisiana. The facility has approximately 340,000 barrels of tank capacity and the tanks vary in sizes ranging from 63,000 gallons to 80,000 barrels. There are three local pipeline connections at the facility, which enable the movement of products from the facility to the petrochemical plants in Geismar, Louisiana.

In June 2006, Kinder Morgan Energy Partners announced the construction of a new $115 million crude oil tank farm located in Edmonton, Alberta, Canada, and long-term contracts with customers for all of the available capacity at the facility. Situated on approximately 24 acres, the new storage facility will have nine tanks with a combined storage capacity of approximately 2.2 million barrels for crude oil. Service is expected to begin in the fourth quarter of 2007, and when completed, the tank farm will serve as a premier blending and storage hub for Canadian crude oil. The tank farm will have access to more than 20 incoming pipelines and several major outbound systems, including a connection with our 710-mile Trans Mountain Pipeline system, which currently transports up to 225,000 barrels per day of heavy crude oil and refined products from Edmonton to marketing terminals and refineries located in the greater Vancouver, British Columbia area and Puget Sound in Washington state.

Competition. Kinder Morgan Energy Partners is one of the largest independent operators of liquids terminals in North America. Its primary competitors are IMTT, Magellan, Morgan Stanley, Oil Tanking, Teppco, Valero and Vopak.

Bulk Terminals

Kinder Morgan Energy Partners' bulk terminal operations primarily involve dry-bulk material handling services; however, Kinder Morgan Energy Partners also provides terminal engineering and design services and in-plant services covering material handling, conveying, maintenance and repair, railcar switching and miscellaneous marine services. Combined, Kinder Morgan Energy Partners' dry-bulk and material transloading facilities handled approximately 89.5 million tons of coal, petroleum coke, steel and other dry-bulk materials in 2006. Kinder Morgan Energy Partners owns or operates approximately 28 petroleum coke or coal terminals in the United States. Major bulk terminal assets of this segment are described below.

In 2006, Kinder Morgan Energy Partners handled approximately 16.6 million tons of petroleum coke, as compared to approximately 12.3 million tons in 2005. Petroleum coke is a by-product of the crude oil refining process and has characteristics similar to coal. It is used in domestic utility and industrial steam generation facilities. It is also used by the steel industry in the manufacture of ferro alloys, and for the manufacture of carbon and graphite products. Petroleum coke supply in the United States has increased in the last several years due to an increasingly heavy crude oil supply and also to the increased use of coking units by domestic refineries. A portion of the petroleum coke we handle is imported from or exported to foreign markets. Most of Kinder Morgan Energy Partners' customers are large integrated oil companies that choose to outsource the storage and loading of petroleum coke for a fee.

The overall increase in petroleum coke volumes in 2006 versus 2005 was largely driven by incremental volumes attributable to Kinder Morgan Energy Partners' purchase of certain petroleum coke terminal operations from Trans-Global Solutions, Inc. in April 2005. Kinder Morgan Energy Partners paid an aggregate consideration of approximately $247.2 million for these operations, and the acquisition made Kinder Morgan Energy Partners the largest independent handler of petroleum coke in the United States, in terms of volume. All of the acquired assets are located in the State of Texas, and include facilities at the Port of Houston, the Port of Beaumont and the TGS Deepwater Terminal located on the Houston Ship Channel. The facilities also provide handling and storage services for a variety of other bulk materials.

In 2006, Kinder Morgan Energy Partners also handled approximately 30.8 million tons of coal. Coal continues to be the fuel of choice for electric generation plants, accounting for more than 50% of United States electric generation feedstock. Forecasts of overall coal usage and power plant usage for the next 20 years show an increase of about 1.5% per year. Current domestic supplies are predicted to last for several hundred years. Most coal transloaded through Kinder Morgan Energy Partners' coal terminals is destined for use in coal-fired electric generation facilities.

The Cora terminal is a high-speed, rail-to-barge coal transfer and storage facility. The terminal is located on approximately 480 acres of land along the upper Mississippi River near Chester, Illinois, about 80 miles south of St. Louis, Missouri. It currently has a throughput capacity of about 10 million tons per year and is currently equipped to store up to one million tons of coal. This storage capacity provides customers the flexibility to coordinate their supplies of coal with the demand at power plants. The Cora terminal sits on the mainline of the Union Pacific Railroad and is strategically positioned to receive coal shipments from the western United States.

The Grand Rivers, Kentucky terminal is a coal transloading and storage facility located along the Tennessee River just above the Kentucky Dam. The terminal is operated on land under easements with an initial expiration of July 2014 and has current annual throughput capacity of approximately 12 million tons with a storage capacity of approximately one million tons. The Grand Rivers terminal provides easy access to the Ohio-Mississippi River network and the Tennessee-Tombigbee River system. The Paducah & Louisville Railroad, a short line railroad, serves Grand Rivers with connections to seven Class I rail lines including the Union Pacific, CSX, Illinois Central and Burlington Northern Santa Fe.

The Cora and Grand Rivers terminals handle low sulfur coal originating in Wyoming, Colorado, and Utah, as well as coal that originates in the mines of southern Illinois and western Kentucky. However, since many shippers, particularly in the East, are using western coal or a mixture of western coal and other coals as a means of meeting environmental restrictions, we anticipate that growth in volume through the two terminals will be primarily due to increased use of western low sulfur coal originating in Wyoming, Colorado and Utah.

The Pier IX terminal is located in Newport News, Virginia. The terminal has the capacity to transload approximately 12 million tons of coal annually. It can store 1.4 million tons of coal on its 30-acre storage site. For coal, the terminal offers blending services and rail to storage or direct transfer to ship; for other dry bulk products, the terminal offers ship to storage to rail or truck. The Pier IX terminal exports coal to foreign markets, serves power plants on the eastern seaboard of the United States, and imports cement pursuant to a long-term contract. The terminal operates a cement facility which has the capacity to transload over 400,000 tons of cement annually. Pier IX also operates two synfuel plants on site, which together produced 3.3 million tons of synfuel in 2006. The Pier IX terminal is served by the CSX Railroad, which transports coal from central Appalachian and other eastern coal basins. Cement imported to the Pier IX terminal primarily originates in Europe.

In March 2006, Kinder Morgan Energy Partners announced that it entered into a long-term agreement with Drummond Coal Sales, Inc. that will support a $70 million expansion of the Pier IX terminal. The project includes the construction of a new ship dock and the installation of additional equipment, and it is expected to increase throughput at the terminal by approximately 30% and to allow the terminal to begin receiving shipments of imported coal. The expansion project is expected to be completed in the first quarter of 2008. Upon completion, the terminal will have an import capacity of up to 9 million tons annually.

The Shipyard River terminal is located in Charleston, South Carolina, on 208 acres, and is both a bulk and liquids terminal. The Shipyard facility is able to unload, store and reload coal, petroleum coke, cement and other bulk products imported from or exported to various foreign countries. The imported coal is often a cleaner-burning, low-sulfur coal and it is used by local utilities to comply with the U.S. Clean Air Act. The Shipyard River terminal has the capacity to handle approximately 2.5 million tons of coal and petroleum coke per year and offers approximately 300,000 tons of total storage, of which 50,000 tons are under roof. The facility is serviced by the Norfolk Southern and CSX railroads. Kinder Morgan Energy Partners is currently expanding the Shipyard River terminal in order to increase the terminal's throughput and to allow for the handling of increasing supplies of imported coal. In addition, the terminal has over 1.0 million barrels of liquid storage capacity in 18 tanks.

The Kinder Morgan Tampaplex terminal, a marine terminal located in Tampa, Florida, sits on a 114-acre site and serves as a storage and receipt point for imported fertilizer, aggregates and ammonia, as well as an export location for dry bulk products, including fertilizer and animal feed. The terminal also includes an inland bulk storage warehouse facility used for overflow cargoes from Kinder Morgan Energy Partners' Port Sutton import terminal, which is also located in Tampa. The Port Sutton terminal sits on 16 acres of land and offers 200,000 tons of covered storage. Primary products handled in 2006 included fertilizers, salt, ores, and liquid chemicals. Also in the Tampa Bay area are Kinder Morgan Energy Partners' Port Manatee and Hartford Street terminals. Port Manatee has four warehouses which can store 130,000 tons of bulk products. Products handled at Port Manatee include fertilizers, ores and other general cargo. At the Hartford Street terminal, anhydrous ammonia and fertilizers are handled and stored in two warehouses with an aggregate capacity of 23,000 net tons.

The Kinder Morgan Fairless Hills terminal consists of substantially all of the assets used to operate the major port distribution facility located at the Fairless Industrial Park in Bucks County, Pennsylvania. Located on the bend of the Delaware River below Trenton, New Jersey, the terminal is the largest port on the East Coast for the handling of semi-finished steel slabs. The facility also handles other types of specialized cargo that caters to the construction industry and service centers that use steel sheet and plate. The port has four ship berths with a total length of 2,200 feet and a maximum draft of 38.5 feet. It contains two mobile harbor cranes and is served by connections to two Class I rail lines: CSX and Norfolk Southern.

The Pinney Dock terminal is located in Ashtabula, Ohio along Lake Erie. It handles iron ore, titanium ore, magnetite and other aggregates. Pinney Dock has six docks with 15,000 feet of vessel berthing space, 200 acres of outside storage space, 400,000 feet of warehouse space and two 45-ton gantry cranes.

The Chesapeake Bay bulk terminal facility is located at Sparrows Point, Maryland. It offers stevedoring services, storage, and rail, ground, or water transportation for products such as coal, petroleum coke, iron and steel slag, and other mineral products. It offers both warehouse and approximately 100 acres of open storage.

The Milwaukee and Dakota dry-bulk commodity facilities are located in Milwaukee, Wisconsin and St. Paul, Minnesota, respectively. The Milwaukee terminal is located on 34 acres of property leased from the Port of Milwaukee. Its major cargoes are coal and bulk de-icing salt. The Dakota terminal is on 55 acres in St. Paul and primarily handles salt, grain products and cement. The Dakota terminal has a cement loading facility for unloading cement from barges and railcars, conveying and storing product, and loading and weighing trucks and railcars. It covers nearly nine acres and can handle approximately 400,000 tons of cement each year.

Competition. Kinder Morgan Energy Partners' petroleum coke and other bulk terminals compete with numerous independent terminal operators, other terminals owned by oil companies, stevedoring companies and other industrials opting not to outsource terminal services. Many of Kinder Morgan Energy Partners' other bulk terminals were constructed pursuant to long-term contracts for specific customers. As a result, we believe other terminal operators would face a significant disadvantage in competing for this business. The Cora and Grand Rivers coal terminals compete with two third-party coal terminals that also serve the Midwest United States. While the Cora and Grand Rivers terminals are modern high capacity coal terminals, some volume is diverted to these third-party terminals by the Tennessee Valley Authority in order to promote increased competition. The Pier IX terminal competes primarily with two modern coal terminals located in the same Virginian port complex as the Pier IX terminal.

Materials Services (rail transloading)

Kinder Morgan Energy Partners' materials services operations include the rail or truck transloading operations owned by Kinder Morgan Materials Services LLC, Lomita Rail Terminal LLC, Kinder Morgan Texas Terminals, L.P., Transload Services, LLC and other stevedoring and in-plant operations. In 2006, Kinder Morgan Energy Partners acquired all of the membership interests of Lomita Rail Terminal LLC and Transload Services, LLC, and the terminal assets and operations of A&L Trucking, L.P. For more information on these acquisitions, see Note 4 to our consolidated financial statements included elsewhere in this report.

The materials services operations consist of approximately 61 rail transloading facilities, of which 56 are located east of the Mississippi River. The CSX, Norfolk Southern, Union Pacific, Kansas City Southern and A&W railroads provide rail service for these terminal facilities. Approximately 50% of the products handled are liquids, including an entire spectrum of liquid chemicals, and 50% are dry bulk products. Many of the facilities are equipped for bi-modal operation (rail-to-truck, and truck-to-rail). Kinder Morgan Energy Partners also designs and builds transloading facilities, performs inventory management services, and provides value-added services such as blending, heating and sparging. In 2006, the materials services operations handled approximately 72,000 railcars.

Regulation

Interstate Common Carrier Pipeline Rate Regulation – U.S. Operations

Our petroleum products pipelines are interstate common carrier pipelines, subject to regulation by the Federal Energy Regulatory Commission under the Interstate Commerce Act, or ICA. The ICA requires that we maintain our tariffs on file with the FERC, which tariffs set forth the rates we charge for providing transportation services on our interstate common carrier pipelines as well as the rules and regulations governing these services. The ICA requires, among other things, that such rates on interstate common carrier pipelines be "just and reasonable" and nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation. The FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained during the two years prior to the filing of a complaint.

On October 24, 1992, Congress passed the Energy Policy Act of 1992. The Energy Policy Act deemed petroleum products pipeline tariff rates that were in effect for the 365-day period ending on the date of enactment or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period to be just and reasonable or "grandfathered" under the ICA. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. The rates we charge for transportation service on our North System and Cypress Pipeline were not suspended or subject to protest or complaint during the relevant 365-day period established by the Energy Policy Act. For this reason, we believe these rates should be grandfathered under the Energy Policy Act. Certain rates on our Pacific operations' pipeline system were subject to protest during the 365-day period established by the Energy Policy Act. Accordingly, certain of the Pacific pipelines' rates have been, and continue to be, subject to complaints with the FERC, as is more fully described in Note 19 to our consolidated financial statements included elsewhere in this report.

Petroleum products pipelines may change their rates within prescribed ceiling levels that are tied to an inflation index. Shippers may protest rate increases made within the ceiling levels, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs from the previous year. A pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, uses cost-of-service ratemaking, market-based rates and settlement rates as alternatives to the indexing approach in certain specified circumstances.

During the first quarter of 2003, the FERC made a significant positive adjustment to the index which petroleum products pipelines use to adjust their regulated tariffs for inflation. The former index used percent growth in the producer price index for finished goods, and then subtracted one percent. The index adjustment in 2003 eliminated the one percent reduction. Pursuant to a subsequent review of the index by the FERC in 2005, the index is now measured by the producer price index for finished goods plus 1.3% and it applies for years 2006 through 2010. As a result, we filed for indexed rate adjustments on a number of our petroleum products pipelines and realized benefits from the new index.

Interstate Natural Gas Pipeline Regulation – U.S. Operations

Under the Natural Gas Act of 1938 and, to a lesser extent, the Natural Gas Policy Act of 1978, the FERC regulates both the performance of interstate transportation and storage services by interstate natural gas pipeline companies, and the rates charged for such services. The rates, terms and conditions of such services are subject to tariffs approved by the FERC. Rates are designed to recover an interstate pipeline's costs of providing service, including financing costs, and to provide an opportunity to earn a reasonable and fair return on common equity. The rates that are set do not guaranty that a fair and reasonable return will be earned, and actual returns may vary from year to year according to various factors, including the total amount of services under contract, new investment, and increases in the cost of providing service.

In establishing the rates that an interstate pipeline may charge its customers, the FERC will generally consider an interstate pipeline's rate base investment, costs, and revenues for a given test period, with adjustments for known and measurable changes. It will also look at the interstate pipeline's capital structure and the cost of capital to determine whether existing rates need to be adjusted to establish new rates which are just and reasonable and sufficient to provide an opportunity to earn a fair and reasonable return on rate base. Rate base is generally the net depreciated cost of property, plant and equipment that is used or useful in providing service. A fair and reasonable return is established by determining the cost of individual components of the capital structure, including debt costs and a return on common equity, and weighting such costs to determine an aggregate return on rate base. The FERC also regulates the construction of pipelines and facilities used to transport or store natural gas in interstate commerce. Those wishing to build facilities or operate pipelines first must obtain a Certificate of Public Convenience and Necessity from the FERC.

Beginning in the mid-1980's, the FERC initiated a number of regulatory changes intended to create a more competitive environment in the natural gas marketplace. Among the most important of these changes were:

- Order No. 436 (1985) requiring open-access, nondiscriminatory transportation of natural gas;
- Order No. 497 (1988) which set forth new standards and guidelines imposing certain constraints on the interaction between interstate natural gas pipelines and their marketing affiliates and imposing certain disclosure requirements regarding that interaction; and
- Order No. 636 (1992) which required interstate natural gas pipelines that perform open-access transportation under blanket certificates to "unbundle" or separate their traditional merchant sales services from their transportation and storage services and to provide comparable transportation and storage services with respect to all natural gas supplies whether purchased from the pipeline or from other merchants such as marketers or producers.

Natural gas pipelines must now separately state the applicable rates for each unbundled service they provide (*i.e.,* for the natural gas commodity, transportation and storage). Order 636 contains a number of procedures designed to increase competition in the interstate natural gas industry, including:

- requiring the unbundling of sales services from other services;
- permitting holders of firm capacity on interstate natural gas pipelines to release all or a part of their capacity for resale by the pipeline; and
- the issuance of blanket sales certificates to interstate pipelines for unbundled services.

On November 25, 2003, the FERC issued Order No. 2004, adopting revised Standards of Conduct that apply uniformly to interstate natural gas pipelines and public utilities. In light of the changing structure of the energy industry, these Standards of Conduct govern relationships between regulated interstate natural gas pipelines and all of their energy affiliates. These new Standards of Conduct were designed to eliminate the loophole in the previous regulations that did not cover an interstate natural gas pipeline's relationship with energy affiliates that are not marketers. The rule is designed to prevent interstate natural gas pipelines from giving an undue preference to any of their energy affiliates and to ensure that transmission is provided on a nondiscriminatory basis. In addition, unlike the prior regulations, these requirements apply even if the energy affiliate is not a customer of its affiliated interstate pipeline. The effective date of Order No. 2004 was September 22, 2004. Our interstate natural gas pipelines have implemented compliance with these Standards of Conduct.

On November 17, 2006, the D.C. Circuit vacated Order No. 2004, as applied to natural gas pipelines, and remanded the Order back to the FERC. On January 9, 2007, the FERC issued an interim rule regarding standards of conduct in Order No. 690 to be effective immediately. The interim rule repromulgated the standards of conduct that were not challenged before the court. On January 18, 2007, the FERC issued a notice of proposed rulemaking soliciting comments on whether or not the interim rule should be made permanent for natural gas transmission providers. Please refer to Note 18 to our consolidated financial statements included elsewhere in this report for additional information regarding FERC Order No. 2004 and other Standards of Conduct rulemaking.

On August 8, 2005, Congress enacted the Energy Policy Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act to prohibit market manipulation by any entity, directed the FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce, and significantly increased the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder.

California Public Utilities Commission Rate Regulation

The intrastate common carrier operations of our Pacific operations' pipelines in California are subject to regulation by the California Public Utilities Commission under a "depreciated book plant" methodology, which is based on an original cost measure of investment. Intrastate tariffs filed by us with the CPUC have been established on the basis of revenues, expenses and investments allocated as applicable to the California intrastate portion of our Pacific operations' business. Tariff rates with respect to intrastate pipeline service in California are subject to challenge by complaint by interested parties or by independent action of the CPUC. A variety of factors can affect the rates of return permitted by the CPUC, and certain other issues similar to those which have arisen with respect to our FERC regulated rates could also arise with respect to our intrastate rates. Certain of our Pacific operations' pipeline rates have been, and continue to be, subject to complaints with the CPUC, as is more fully described in Note 19 to our consolidated financial statements.

Regulation of Canada-based Assets

Terasen Gas

<u>Terasen Gas Inc.</u>

Gas utilities in British Columbia are subject to the regulatory jurisdiction of the BCUC which derives its powers from the Utilities Commission Act (British Columbia). In addition to approving the rate base and new financings of Terasen Gas Inc., the BCUC also approves the rates charged to customers. These rates are designed to recover the utility's costs of providing service and allow the opportunity to meet financial commitments and earn a reasonable and fair return on common equity. The BCUC has jurisdiction to regulate and approve the terms and conditions under which gas utilities provide service.

As part of the establishment of the rates that a gas utility charges its customers, the BCUC establishes a rate base, approves a capital structure with which to finance such rate base, and is responsible for setting a reasonable and fair return on the debt and equity in the approved capital structure. Rate base is the aggregate of the depreciated cost of property, plant and equipment that are used or useful in serving the public, certain deferral accounts and a reasonable allowance for working capital. The fair return is established by determining the cost of individual components of the capital structure, including return on common equity, and weighting such costs to determine an aggregate return on rate base. The rates that are established and the terms and conditions of service are contained in a schedule of published and public tariffs. Before any tariff can be put into effect, it must be filed with and approved by the BCUC. The BCUC has jurisdiction to approve or refuse any tariff amendment submitted for filing and to determine the rates which should be charged by a utility for its services. The BCUC is required to have due regard, among other things, to fixing rates that are not unjust or unreasonable. In fixing rates the BCUC must determine that such rates reflect a fair and reasonable charge for service of the nature and quality furnished by Terasen Gas Inc. to its customers and that such rates are sufficient to yield Terasen Gas Inc. a fair and reasonable compensation for its services and a fair and reasonable return on its rate base.

The BCUC uses a future test year in the establishment of rates for a utility. Pursuant to this method, the BCUC approves Terasen Gas Inc.'s forecast volume of gas that will be sold and transported, together with all of the costs (including the rate of return) that Terasen Gas Inc. will incur in the test year. Rates are fixed to permit Terasen Gas Inc. to collect all of its costs (including the rate of return) if the forecast sales and transportation volumes are achieved. The forecast sales volumes assume normal weather. Certain costs are fixed and will be incurred regardless of the actual volume of gas sold. Accordingly, if the actual volumes of gas sales are less than those forecast in the test year, Terasen Gas Inc. might not recover all of the fixed costs. Interest expense, taxes other than income taxes, depreciation and amortization, certain operations and maintenance costs, the portion of the cost of gas that is fixed such as demand charges or reservation fees, and the fixed portion of transportation costs have the effect of being virtually fixed costs.

Two mechanisms to ameliorate unanticipated changes in sales volumes, such as changes caused by weather, have been implemented specifically for Terasen Gas Inc. The first relates to the recovery of all gas costs through deferral accounts which capture all variances (overages and shortfalls) from forecasts. Balances are either refunded to or recovered from customers via an application with the BCUC. The deferral accounts are called the Commodity Cost Reconciliation Account and the Midstream Cost Reconciliation Account. The second mechanism seeks to stabilize delivery revenues from residential and commercial customers through a deferral account that captures variances in the forecast versus actual customer use throughout the year. This mechanism is called the Revenue Stabilization Adjustment Mechanism. In February 2001, the BCUC issued guidelines for quarterly calculations to be prepared to determine whether customer rate adjustments are needed to reflect prevailing market prices for natural gas and to ensure that rate stabilization account balances are recovered on a timely basis.

Terasen Gas Inc. also has in place short-term and long-term interest rate deferral accounts to absorb interest rate fluctuations. The interest rate deferral accounts that were in place during 2006 effectively fixed the interest expense on short-term funds attributable to Terasen Gas Inc.'s regulated assets at 4.00 percent during 2006. The effective fixed short-term interest rate for 2007 has been set at 4.75 percent.

In addition to application for approval of interim and annual rate changes, the gas utilities may apply from time to time to the BCUC for rate changes to give effect to the changes in costs beyond the control of the utilities.

Important regulatory information, pertaining to decisions made by the BCUC with respect to Terasen Gas Inc., is summarized in the following table.

	Year ended December 31,			
	2007	2006	2005	2004
	(Canadian dollar amounts in millions)			
Rate Base	$ 2,474	$ 2,506	$ 2,306	$ 2,310
Deemed Common Equity Component of Total Capital Structure	35.01%	35%	33%	33%
Allowed Rate of Return on Common Equity	8.37%	8.80%	9.03%	9.15%

Terasen Gas Inc.'s allowed rates of return on common equity ("ROE") are determined annually based on a formula that applies a risk premium to a forecast of long-term Government of Canada bond yields. On June 30, 2005, Terasen Gas Inc. applied to the BCUC to increase the deemed equity components from 33% to 38%. The application also requested an increase in allowed ROEs from the levels that result from the then current formula, which would have yielded 8.29% for Terasen Gas Inc. in 2006. The BCUC rendered its decision on the application on March 2, 2006, but effective as of January 1, 2006. The generic ROE formula for a benchmark utility in British Columbia was changed such that it will be reset annually from a forecast of 30-year Canada Bonds plus a 3.90% risk premium when the forecast yield on 30-year Canada Bonds is 5.25%. The risk premium is adjusted annually by 75% of the difference between 5.25% and the forecast yield on 30-year Canada Bonds. For 2006, the forecast 30-year Canada Bond yield was 4.79% resulting in a Benchmark ROE for Terasen Gas Inc. of 8.80%, an improvement of 51 basis points over the old formula. In addition, the BCUC increased the deemed equity component for Terasen Gas Inc. to 35% from 33%. For 2007, the allowed ROE for Terasen Gas Inc. is 8.37%.

2004-2007 Performance-Based Rate Plan: In 2003, Terasen Gas Inc. received BCUC approval of a negotiated settlement of a 2004-2007 Performance-Based Rate Plan ("PBR Settlement"). The PBR Settlement, which took effect January 1, 2004, establishes a process for determining Terasen Gas Inc.'s delivery charges and incentive mechanisms for improved operating efficiencies. The four-year agreement includes incentives for Terasen Gas Inc. to operate more efficiently through sharing of the benefits of cost reductions between Terasen Gas Inc. and its customers. It includes 10 service quality indicators designed to ensure Terasen Gas Inc. provides appropriate service levels and sets out the requirements for an annual review process which will provide a forum for discussion between Terasen Gas Inc. and interested parties regarding its current performance and future activities.

Operation and maintenance costs and base capital expenditures are subject to an incentive formula reflecting increasing costs due to customer growth and inflation, less a productivity factor based on 50% of inflation during the first two years and 66% of inflation during the last two years. Base capital expenditure amounts are a function of customer numbers and projected customer additions. The PBR Settlement provides for a 50/50 customer/shareholder sharing mechanism of earnings above or below the allowed return on equity.

Terasen Gas Inc. has applied for an extension of the 2004-2007 PBR settlement agreement. After an extensive stakeholder consultation process, Terasen Gas Inc. filed an application for approval of a two-year extension to the current 2004-2007 Multi-Year Performance Based Rate Plan. The application requests approval to extend the existing settlement term for 2008-2009. The BCUC has determined that the applications will be reviewed through a written public process throughout February, with a decision expected in March 2007.

Amalgamation of Terasen Gas (Squamish) Inc.: On November 2, 2006, the government of British Columbia approved the amalgamation of Terasen Gas (Squamish) Inc. ("TGS") with Terasen Gas Inc. Effective January 1, 2007, natural gas rates charged to TGS customers were aligned with the Terasen Gas Inc. rates. Integration of TGS into Terasen Gas Inc. resulted in changes to regulatory oversight. The BCUC will now have sole authority over the amalgamated company, whereas TGS was regulated through contractual agreements with the province and the BCUC.

Unbundling: Over the past several years, Terasen Gas Inc., the BCUC and a number of interested parties have laid the groundwork for the introduction of natural gas commodity unbundling. On November 1, 2004, commercial customers of Terasen Gas Inc. became eligible to sign up to buy their natural gas commodity supply directly from third-party suppliers. Terasen Gas Inc. continues to provide delivery of the natural gas. Approximately 79,000 commercial customers are eligible to participate in commodity unbundling. By December 31, 2006, 18,700 customers elected to participate in this program.

During 2006, the BCUC approved offering commodity supply choice to residential customers. The BCUC agreed to open a portion of the province's residential natural gas market to competition, allowing homeowners to sign long-term fixed price contracts for natural gas with companies other than Terasen Gas Inc. starting in May 2007. Consumers can choose to remain with Terasen Gas Inc. or sign with a marketer, in which case they will begin receiving gas at the marketer's rate starting in November 2007. Terasen Gas Inc. will continue to provide delivery service to unbundled customers and delivery margins are not expected to be impacted by migration of residential customers to alternative commodity suppliers.

TGVI

The Province of British Columbia and TGVI's previous parent company entered into the Vancouver Island Natural Gas Pipeline Agreement (the "VINGPA") to restructure the financial arrangements relating to TGVI's pipeline and connected distribution systems. Under the VINGPA, the Province agreed to make quarterly payments from 1996 through 2011 related to natural gas production royalties associated with deemed volumes of natural gas transported through the Vancouver Island pipeline. The royalty related payment recognized in 2006 was C$36.3 million. Under the VINGPA, TGVI's parent company agreed to provide future financial support of up to C$120 million over the period from 1996 to 2011 and C$17.5 million for 1995 to finance the principal amount of the revenue deficiencies incurred by TGVI. Annual revenue deficiencies were calculated as the difference between the regulated allowed return on approved rate base and earnings actually derived from sales revenues and expenses. The accumulated revenue deficiency resulting from overall revenues being below the cost of service had been recorded in a Revenue Deficiency Deferral Account ("RDDA").

When Terasen acquired TGVI, the amount of the RDDA was C$85 million, for which Terasen paid a price of C$61 million. The accumulated RDDA totaled C$30.9 million at December 31, 2006, corresponding to a balance for TGVI regulatory purposes of C$41.4 million, down C$4.3 million from December 31, 2005. Terasen is committed to fund any increases in revenue deficiencies by purchasing preferred shares or subordinated debt issued by TGVI. The BCUC was directed to set rates beginning in 2003 that amortize the RDDA balance over the shortest period reasonably possible, having regard for TGVI's competitive position relative to alternative energy sources and the desirability of reasonable rates. As part of the acquisition of TGVI, Terasen assumed the rights and obligations of TGVI's previous parent company under the VINGPA.

TGVI's distribution rates are set by the BCUC in accordance with regulatory principles generally applied by the BCUC to natural gas utilities operating within British Columbia. On November 30, 2005, TGVI received BCUC approval for a new regulatory settlement, which took effect January 1, 2006. The 2006-2007 settlement provides for a continuation of operation and maintenance cost incentive arrangements previously in place. As noted above, on March 2, 2006, the BCUC issued its Decision on the ROE application. In the Decision, TGVI's request for an increase in its deemed equity components from 35% to 40% was approved. The Decision also resulted in an improvement in its allowed ROE to 70 basis points over the Benchmark ROE to 9.50% to be effective January 1, 2006. Due to a decline in the forecast benchmark 30-year Canada Bond, the allowed ROE has been set at 9.07% for 2007.

TGVI has applied for an extension of its settlement agreement which expires at the end of 2007. After an extensive stakeholder consultation process, TGVI filed an application for approval of a two-year extension to the current 2006-2007 Negotiated Settlement Agreement. The BCUC has determined that the application will be reviewed through a written public process throughout February/March, with a decision expected in March 2007.

Kinder Morgan Canada

Trans Mountain

The Canadian portion of the crude oil and refined product pipeline system is under the regulatory jurisdiction of the NEB. The National Energy Board Act gives the NEB power to authorize pipeline construction and to establish tolls and conditions of service.

In November 2004, Trans Mountain entered into negotiations with CAPP and principal shippers for a new Incentive Toll Settlement to be effective for the period starting January 1, 2006 and ending December 31, 2010 (the "2006 ITS"). In January 2006, Trans Mountain reached agreement in principle reduced to a memorandum of understanding for the 2006 ITS. A final agreement was reached with CAPP in October 2006 and NEB approval was received in November 2006. The 2006 ITS incorporates an incentive toll mechanism that is intended to provide Trans Mountain with the opportunity to earn a return on equity greater than that calculated using the formula established by the NEB. In return for this opportunity, Trans Mountain has agreed to assume certain risks and provide cost certainty in certain areas. Part of the incentive toll mechanism specifies that Trans Mountain is allowed to keep 75% of the revenue generated by throughput in excess of 92.5% of the capacity of the pipeline. The 2006 ITS provides for base tolls which will, other than recalculation or adjustment in certain specified circumstances, remain in effect for the five-year period. The 2006 ITS also governs the financial arrangements for the approximately C$638 million in planned expansions to Trans Mountain that will add 75,000 bpd of incremental capacity to the system by late 2008.

The toll charged for the portion of Trans Mountain's pipeline system located in the United States falls under the jurisdiction of the FERC. See "Interstate Common Carrier Pipeline Rate Regulation – U.S. Operations" preceding.

Corridor

As an intra-provincial pipeline system, Corridor is subject to the jurisdiction of the Alberta Energy and Utilities Board ("AEUB"). With respect to Corridor, matters such as rates of return, construction and operation of facilities and tolls are governed by contractual arrangements with shippers and are subject to regulation by the AEUB. The Firm Service Agreement ("FSA"), which was effective, from a tolling perspective, with the commencement of commercial operations on May 1, 2003, sets pipeline tolls based on cost of service mechanisms. Shell and its partners have made a 25-year take or pay commitment under the FSA to transport a total of 150,000 bpd of bitumen and 65,000 bpd of diluent in the Corridor Pipeline.

Express

The Canadian segment of the Express Pipeline is regulated by the NEB as a Group 2 pipeline, which results in rates and terms of service being regulated on a complaint basis only. The U.S. segment of the Express Pipeline and the Platte Pipeline are regulated by the FERC, which regulates the rates and terms of service of a common carrier. The FERC has additionally established methods by which pipelines may increase their rates.

Express committed rates are subject to a 2% inflation adjustment April 1 of each year. Uncommitted or ceiling rates for both the U.S. segment of Express Pipeline and Platte Pipeline are subject to adjustment in accordance with the FERC's annual indexing formula. Platte has historically been unable to charge its ceiling rates and has had to discount its rates because of market fundamentals in PADD II. With changes in market conditions over the past year, Platte has been able to successfully remove all of its discounts. Today, all rates on Platte are at the applicable ceiling level.

Additionally, movements on the Platte Pipeline within the State of Wyoming are regulated by the Wyoming Public Service Commission ("WPSC"), which regulates the tariffs and terms of service of public utilities that operate in the State of Wyoming. The WPSC standards applicable to rates are similar to those of the FERC and the NEB.

Safety Regulation

Our interstate pipelines are subject to regulation by the United States Department of Transportation and our intrastate pipelines and other operations are subject to comparable state regulations with respect to their design, installation, testing, construction, operation, replacement and management. We must permit access to and copying of records, and make certain reports and provide information as required by the Secretary of Transportation. Comparable regulation exists in some states in which we conduct pipeline operations. In addition, our truck and terminal loading facilities are subject to U.S. DOT regulations dealing with the transportation of hazardous materials by motor vehicles and railcars. We believe that we are in substantial compliance with U.S. DOT and comparable state regulations.

The Pipeline Safety Improvement Act of 2002 provides guidelines in the areas of testing, education, training and communication. The Pipeline Safety Act requires pipeline companies to perform integrity tests on natural gas transmission pipelines that exist in high population density areas that are designated as High Consequence Areas. Pipeline companies are required to perform the integrity tests within ten years of the date of enactment and must perform subsequent integrity tests on a seven year cycle. At least 50% of the highest risk segments must be tested within five years of the enactment date. The risk ratings are based on numerous factors, including the population density in the geographic regions served by a particular pipeline, as well as the age and condition of the pipeline and its protective coating. Testing consists of hydrostatic testing, internal magnetic flux or ultrasonic testing, or direct assessment of the piping. In addition to the pipeline integrity tests, pipeline companies must implement a qualification program to make certain that employees are properly trained, and the U.S. DOT has approved our qualification program. We believe that we are in substantial compliance with this law's requirements and have integrated appropriate aspects of this pipeline safety law into our internal Operator Qualification Program. A similar integrity management rule for refined petroleum products pipelines became effective May 29, 2001. All baseline assessments for products pipelines must be completed by March 31, 2008. We expect to meet the required deadlines for both our natural gas and refined petroleum products pipelines.

Certain of our products pipelines have been issued orders and civil penalties by the U.S. DOT's Office of Pipeline Safety concerning alleged violations of certain federal regulations concerning our products pipeline integrity management program. However, we dispute some of the Office of Pipeline Safety findings and disagree that civil penalties are appropriate for them, and we therefore requested an administrative hearing on these matters according to the U.S. DOT regulations. Information on these matters is more fully described in Note 19 to our consolidated financial statements.

On March 25, 2003, the U.S. DOT issued their final rules on Hazardous Materials: Security Requirements for Offerors and Transporters of Hazardous Materials. We believe that we are in substantial compliance with these rules and have made revisions to our Facility Security Plan to remain consistent with the requirements of these rules.

We are also subject to the requirements of the Federal Occupational Safety and Health Act and other comparable federal and state statutes. We believe that we are in substantial compliance with Federal OSHA requirements, including general industry standards, recordkeeping requirements and monitoring of occupational exposure to hazardous substances.

In general, we expect to increase expenditures in the future to comply with higher industry and regulatory safety standards. Some of these changes, such as U.S. DOT implementation of additional hydrostatic testing requirements, could significantly increase the amount of these expenditures. Such expenditures cannot be accurately estimated at this time.

State, Provincial and Local Regulation

Our activities are subject to various state, provincial and local laws and regulations, as well as orders of regulatory bodies, governing a wide variety of matters, including marketing, production, pricing, pollution, protection of the environment, and safety.

Environmental Matters

Our operations are subject to extensive and evolving federal, provincial, state and local laws and regulations governing the release of regulated materials into the environment or otherwise relating to environmental protection or human health or safety. We believe that our operations are in substantial compliance with applicable environmental laws and regulations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of remedial requirements, issuance of injunction as to future compliance or other mandatory or consensual measures. We have an ongoing environmental compliance program. However, risks of accidental leaks or spills are associated with the transportation and storage of natural gas liquids, refined petroleum products, natural gas and carbon dioxide, the handling and storage of liquid and bulk materials and the other activities conducted by us. There can be no assurance that we will not incur significant costs and liabilities relating to claims for damages to property, the environment, natural resources, or persons resulting from the operation of our businesses. Moreover, it is possible that other developments, such as increasingly strict environmental laws and regulations and enforcement policies thereunder, could result in increased costs and liabilities to us.

Environmental laws and regulations have changed substantially and rapidly over the last 35 years, and we anticipate that there will be continuing changes. One trend in environmental regulation is to increase reporting obligations and place more restrictions and limitations on activities, such as emissions of pollutants, generation and disposal of wastes and use, storage and handling of chemical substances that may impact human health and safety or the environment. Increasingly strict environmental restrictions and limitations have resulted in increased operating costs for us and other similar businesses throughout the United States. It is possible that the costs of compliance with environmental laws and regulations may continue to increase. We will attempt to anticipate future regulatory requirements that might be imposed and to plan accordingly, but there can be no assurance that we will identify and properly anticipate each such change, or that our efforts will prevent material costs, if any, from arising.

We are currently involved in environmentally related legal proceedings and clean up activities. Although no assurance can be given, we believe that the ultimate resolution of all these environmental matters will not have a material adverse effect on our business, financial position or results of operations. We have accrued an environmental reserve in the amount of $77.8 million as of December 31, 2006. Our reserve estimates range in value from approximately $77.8 million to approximately $130.7 million, and we have recorded a liability equal to the low end of the range. For additional information related to environmental matters, see Note 19 to our consolidated financial statements included elsewhere in this report.

Solid Waste

We own numerous properties that have been used for many years for the production of crude oil, natural gas and carbon dioxide, the transportation and storage of refined petroleum products and natural gas liquids and the handling and storage of coal and other liquid and bulk materials. Virtually all of these properties were owned by others before us. Solid waste disposal practices within the petroleum industry have changed over the years with the passage and implementation of various environmental laws and regulations. Hydrocarbons and other solid wastes may have been disposed of in, on or under various properties owned by us during the operating history of the facilities located on such properties. Virtually all of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other solid wastes was not under our control. In such cases, hydrocarbons and other solid wastes could migrate from the facilities and have an adverse effect on soils and groundwater. We maintain a reserve to account for the costs of cleanup at sites known to have surface or subsurface contamination requiring response action.

We generate both hazardous and non-hazardous solid wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act and comparable state statutes. From time to time, state regulators and the United States Environmental Protection Agency consider the adoption of stricter disposal standards for non-hazardous waste. Furthermore, it is possible that some wastes that are currently classified as non-hazardous, which could include wastes currently generated during pipeline or liquids or bulk terminal operations, may in the future be designated as "hazardous wastes." Hazardous wastes are subject to more rigorous and costly disposal requirements than non-hazardous wastes. Such changes in the regulations may result in additional capital expenditures or operating expenses for us.

Superfund

The Comprehensive Environmental Response, Compensation and Liability Act, also known as the "Superfund" law or "CERCLA," and analogous state laws, impose joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of "potentially responsible persons" for releases of "hazardous substances" into the environment. These persons include the owner or operator of a site and companies that disposed of or arranged for the disposal of the hazardous substances found at the site. CERCLA authorizes the U.S. EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur, in addition to compensation for natural resource damages, if any. Although "petroleum" is excluded from CERCLA's definition of a "hazardous substance," in the course of our ordinary operations, we have and will generate materials that may fall within the definition of "hazardous substance." By operation of law, if we are determined to be a potentially responsible person, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such materials are present, in addition to compensation for natural resource damages, if any.

Clean Air Act

Our operations are subject to the Clean Air Act, as amended, and analogous state statutes. We believe that the operations of our pipelines, storage facilities and terminals are in substantial compliance with such statutes. The Clean Air Act, as amended, contains lengthy, complex provisions that may result in the imposition over the next several years of certain pollution control requirements with respect to air emissions from the operations of our pipelines, treating facilities, storage facilities and terminals. Depending on the nature of those requirements and any additional requirements that may be imposed by state and local regulatory authorities, we may be required to incur certain capital expenditures over the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals and addressing other air emission-related issues. The Illinois Environmental Protection Agency and the Texas Natural Resource Conservation Commission have proposed regulations that would require reduction of emissions of nitrogen oxides from internal combustion engines. These regulations could result in additional capital expenditures related to installation of emission controls on several compressor engines in each state. However, while additional capital expenditures may be necessary to comply with these regulations, we do not believe that we will be materially adversely impacted by these proposed regulations.

Due to the broad scope and complexity of the issues involved and the resultant complexity and nature of the regulations, full development and implementation of many Clean Air Act regulations by the U.S. EPA and/or various state and local regulators have been delayed. Therefore, until such time as the new Clean Air Act requirements are implemented, we are unable to fully estimate the effect on earnings or operations or the amount and timing of such required capital expenditures. At this time, however, we do not believe that we will be materially adversely affected by any such requirements.

Clean Water Act

Our operations can result in the discharge of pollutants. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and controls regarding the discharge of pollutants into state waters or waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by applicable federal or state authorities. The Oil Pollution Act was enacted in 1990 and amends provisions of the Clean Water Act as they pertain to prevention and response to oil spills. Spill prevention control and countermeasure requirements of the Clean Water Act and some state laws require containment and similar structures to help prevent contamination of navigable waters in the event of an overflow or release. We believe we are in substantial compliance with these laws.

EPA Fuel Specifications/Gasoline Volatility Restrictions

In order to control air pollution in the United States, the U.S. EPA has adopted regulations that require the vapor pressure of motor gasoline sold in the United States to be reduced from May through mid-September of each year. These regulations mandated vapor pressure reductions beginning in 1989, with more stringent restrictions beginning in 1992. States may impose additional volatility restrictions. The regulations have had a substantial effect on the market price and demand for normal butane, and to some extent isobutane, in the United States. Gasoline manufacturers use butanes in the production of motor gasolines. Since normal butane is highly volatile, it is now less desirable for use in blended gasolines sold during the summer months. Although the U.S. EPA regulations have reduced demand and may have contributed to a significant decrease in prices for normal butane, low normal butane prices have not impacted our pipeline business in the same way they would impact a business with commodity price risk. The U.S. EPA regulations have presented the opportunity for additional transportation services on portions of our liquids pipeline systems, for example, our North System. In the summer of 1991, our North System began long-haul transportation of refinery grade normal butane produced in the Chicago area to the Bushton, Kansas area for storage and subsequent transportation north from Bushton during the winter gasoline blending season. That service continues, and we also provide transportation and storage of butane from the Chicago area back to Bushton during the summer season.

Methyl Tertiary-Butyl Ether

Methyl tertiary-butyl ether, referred to in this report as MTBE, is commonly used as an additive in gasoline. It is manufactured by chemically combining a portion of petrochemical production with purchased methanol and is widely used as an oxygenate blended with gasoline to reduce emissions. Due to environmental and health concerns, California mandated the elimination of MTBE from gasoline by January 1, 2004. With certain scientific studies showing that MTBE was having a detrimental effect on water supplies, a number of other states are making moves to ban MTBE also. Although various drafts of The Energy Policy Act of 2005 provided for the gradual phase out of the use of MTBE, the final bill did not include that provision. Instead, the Act eliminated the oxygenate requirement for reformulated gasoline but did not ban the use of MTBE. So, it is likely that the use of MTBE will be phased out through state bans and voluntary shifts to different formulations of gasoline by the refiners.

In California and other states, MTBE-blended gasoline has been banned from use or may be replaced by an ethanol blend. However, due to the lack of dedicated pipelines, ethanol cannot be shipped through pipelines and therefore, we have realized some reduction in California gasoline volumes transported by our Pacific operations' pipelines. However, the conversion from MTBE to ethanol in California has resulted in an increase in ethanol blending services at many of our refined petroleum products terminal facilities, and the fees we earn for ethanol-related services at our terminals more than offset the reduction in pipeline transportation fees. Furthermore, we have aggressively pursued additional ethanol opportunities in other states where MTBE has been banned or where our customers have decided not to market MTBE gasoline.

Our role in conjunction with ethanol is proving beneficial to our various business segments as follows:

- our Products Pipelines' terminals are storing and blending ethanol because unlike MTBE, it cannot flow through refined petroleum products pipelines;

- our Natural Gas Pipelines segment is delivering natural gas through our pipelines to service new ethanol plants that are being constructed in the Midwest (natural gas is the feedstock for ethanol plants); and

- our Terminals segment is entering into liquid storage agreements for ethanol around the country, in such areas as Houston, Chicago, Nebraska and on the East Coast.

Safety and Environmental Protection

Our senior executives are committed to ensuring that we are an industry leader with respect to environmental protection and compliance with environmental policies. Health, safety and environmental issues and initiatives are reported regularly to our senior executives.

Terasen Gas Inc. and Kinder Morgan Canada have been active participants in Canada's Voluntary Climate Change Challenge and Registry, which is now referred to as the Canadian Standards Association Canadian Greenhouse Gas Challenge Registry ("VCR"). For the seventh consecutive year, Terasen Gas Inc. received gold level reporting status from VCR in recognition of its efforts to manage and reduce greenhouse gas emissions. Terasen Gas Inc. received the VCR Leadership award in 2001 and 2003, becoming the only company in its sector to have received the honor twice. The VCR ranking acknowledges Terasen Gas Inc.'s efforts to develop specific measures and voluntarily set reduction targets. Kinder Morgan Canada has achieved a silver level with VCR for the past three years and has registered to participate in the American Petroleum Institute's voluntary program in the United States.

Since mandatory Environment Canada greenhouse gas reporting regulations have been implemented on facilities with reportable annual emissions exceeding 100,000 metric tons of CO_2 equivalent per year, in 2006 Terasen Gas Inc. reported approximately 102,000 metric tons of CO_2 equivalent for 2005 emissions.

We have detailed emergency preparedness plans in place to respond to natural disasters, accidents and emergencies, and regularly test these plans in simulations involving employees and other emergency response organizations. The Company is also committed to monitor and assess its safety and environmental performance regularly. We incorporate safety performance measures into our employee compensation system, set targets and objectives for environmental performance, and conduct safety and environmental audits.

Other

Amounts we spent during 2006, 2005, and 2004 on research and development activities were not material. We employed 8,602 people at December 31, 2006, including employees of our indirect subsidiary KMGP Services Company, Inc., who are dedicated to the operations of Kinder Morgan Energy Partners.

KMGP Services Company, Inc., a subsidiary of Kinder Morgan G.P., Inc., provides employees and Kinder Morgan Services LLC, a subsidiary of Kinder Morgan Management, provides centralized payroll and employee benefits services to Kinder Morgan Management, Kinder Morgan Energy Partners and Kinder Morgan Energy Partners' operating partnerships and subsidiaries (collectively, "the Group"). Employees of KMGP Services Company, Inc. are assigned to work for one or more members of the Group. The direct costs of compensation, benefits expenses, employer taxes and other employer expenses for these employees are allocated and charged by Kinder Morgan Services LLC to the appropriate members of the Group, and the members of the Group reimburse their allocated shares of these direct costs. No profit or margin is charged by Kinder Morgan Services LLC to the members of the Group. Our human resources department provides the administrative support necessary to implement these payroll and benefits services, and the related administrative costs are allocated to members of the Group in accordance with existing expense allocation procedures. The effect of these arrangements is that each member of the Group bears the direct compensation and employee benefits costs of its assigned or partially assigned employees, as the case may be, while also bearing its allocable share of administrative costs. Pursuant to the limited partnership agreement, Kinder Morgan Energy Partners provides reimbursement for its share of these administrative costs and such reimbursements are accounted for as described above. Kinder Morgan Energy Partners reimburses Kinder Morgan Management with respect to the costs incurred or allocated to Kinder Morgan Management in accordance with Kinder Morgan Energy Partners' limited partnership agreement, the Delegation of Control Agreement among Kinder Morgan G.P., Inc., Kinder Morgan Management, Kinder Morgan Energy Partners and others, and Kinder Morgan Management's limited liability company agreement.

Our named executive officers and other employees that provide management or services to both us and the Group are employed by us. Additionally, other of our employees assist Kinder Morgan Energy Partners in the operation of its Natural Gas Pipeline assets. These employees' expenses are allocated without a profit component between us and the appropriate members of the Group.

We are of the opinion that, with only insignificant exceptions, we have satisfactory title to the properties owned and used in our businesses, subject to the liens for current taxes, liens incidental to minor encumbrances, and easements and restrictions which do not materially detract from the value of such property or the interests therein or the use of the properties in our businesses. We generally do not own the land on which our pipelines are constructed. Instead, we obtain the right to construct and operate the pipelines on other people's land for a period of time.

(D) Financial Information about Geographic Areas

Note 17 of the accompanying Notes to Consolidated Financial Statements contains financial information about the geographic areas in which we do business.

(E) Available Information

We make available free of charge on or through our internet website, at www.kindermorgan.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission. Also, we make available free of charge within the "Investors" section of our internet website, at www.kindermorgan.com, and in print to any shareholder who requests, our governance guidelines, the charters of our audit committee, compensation committee and nominating and governance committee, and our code of business conduct and ethics (which applies to our senior financial officers and chief executive officer, among others). Requests for copies may be directed to Investor Relations, Kinder Morgan, Inc., 500 Dallas Street, Suite 1000, Houston, Texas 77002, or telephone (713) 369-9490. We intend to disclose any amendments to our code of business conduct and ethics, and any waiver from a provision of that code granted to our Chief Executive Officer, Chief Financial Officer or Vice President and Controller, on our internet website within four business days following such amendment or waiver. The information contained on or connected to our internet website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the Securities and Exchange Commission.

Item 1A. *Risk Factors.*

You should carefully consider the risks described below, in addition to the other information contained in this document. Realization of any of the following risks could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Failure to complete the proposed transaction that would take us private would likely have an adverse effect on us. There can be no assurance that the conditions to the completion of the merger under which investors led by Richard D. Kinder, our Chairman and Chief Executive Officer, would acquire all of our outstanding common stock (except for shares held by certain stockholders and investors), referred to as the "Going Private" transaction, will be satisfied. In connection with the Going Private transaction, we are subject to several risks, including the following:

On May 26, 2006, the last trading day prior to the announcement of management's proposal of the merger, our common stock closed at $84.41 per share. After that announcement, the stock price rose to trade close to the $100 per share proposal price. Since the merger agreement was signed on August 28, 2006, our common stock has traded generally between $104 and $106 per share. The current price of our common stock may reflect a market assumption that the merger will close. If the merger is not consummated, the stock price would likely retreat from its current trading range.

- Certain costs relating to the merger, including legal, accounting and financial advisory fees, are payable by us whether or not the merger is completed.

- Under circumstances set out in the merger agreement, if the Going Private transaction is not completed we may be required to pay the acquiring company a termination fee of $215 million and reimburse up to $45 million of the acquiring company's expenses, which will be credited against the termination fee if it becomes payable.

- Our management's and our employees' attention will have been diverted from our day-to-day operations, we may experience unusually high employee attrition and our business and customer relationships may be disrupted.

Consummation of the Going Private transaction would result in substantially more debt to us, which could have an adverse effect on us, such as a downgrade of the ratings of our debt securities, which would increase our cost of capital. In response to the May 29, 2006 announcement of the proposal to acquire all of our outstanding common stock, Moody's Investor Services placed both our long-term and short-term debt ratings under review for possible downgrade. On January 5, 2007, after we announced shareholder approval of the Going Private transaction, our debt rating was downgraded by Standard & Poor's to BB- with the anticipated increase in debt that would result if the Going Private transaction is consummated. This factor, combined with the uncertainty that the Going Private transaction or any other proposals or extraordinary transaction will be approved or completed, has limited our access to the commercial paper market. As a result, we are currently utilizing our $800 million credit facility for our short-term borrowing needs. Such uncertainty could also increase our cost of borrowing in the capital markets.

Our substantially increased debt as a result of the Terasen acquisition could adversely affect our financial health and make us more vulnerable to adverse economic conditions. As a result of our acquisition of Terasen, we have significantly more debt outstanding and significantly higher debt service requirements than in the recent past. As of December 31, 2006, we had outstanding approximately $12.8 billion of consolidated debt (excluding Deferrable Interest Debentures Issued to Subsidiary Trusts and Capital Securities). Of this amount, $5.7 billion and $2.4 billion was debt of our subsidiaries of Kinder Morgan Energy Partners and Terasen, Inc., respectively, including their subsidiaries.

Our increased level of debt could have important consequences, such as:

- limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements or potential growth or for other purposes;

- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to make payments on our debt;

- placing us at a competitive disadvantage compared to competitors with less debt; and

- increasing our vulnerability to adverse economic and industry conditions.

Each of these factors is to a large extent dependent on economic, financial, competitive and other factors beyond our control.

Our large amount of floating rate debt makes us vulnerable to increases in interest rates. As of December 31, 2006, we had outstanding approximately $12.8 billion of consolidated debt. Of this amount, excluding debt of Kinder Morgan Energy Partners that is consolidated as a result of EITF No. 04-5, approximately 50% was subject to floating interest rates, either as short-term commercial paper or as long-term fixed-rate debt converted to floating rates through the use of interest rate swaps. Should interest rates increase significantly, our cash available to service our debt would be adversely affected.

Kinder Morgan Energy Partners could be treated as a corporation for United States income tax purposes. Kinder Morgan Energy Partners' treatment as a corporation would substantially reduce the cash distributions on the common units that it distributes quarterly. The anticipated benefit of our investment in Kinder Morgan Energy Partners depends largely on its treatment as a partnership for federal income tax purposes. Kinder Morgan Energy Partners has not requested, and does not plan to request, a ruling from the Internal Revenue Service on this or any other matter affecting Kinder Morgan Energy Partners. Current law requires Kinder Morgan Energy Partners to derive at least 90% of its annual gross income from specific activities to continue to be treated as a partnership for federal income tax purposes. Kinder Morgan Energy Partners may not find it possible, regardless of its efforts, to meet this income requirement or may inadvertently fail to meet this income requirement. Current law may change so as to cause Kinder Morgan Energy Partners to be treated as a corporation for federal income tax purposes without regard to its sources of income or otherwise subject it to entity-level taxation.

If Kinder Morgan Energy Partners was to be treated as a corporation for federal income tax purposes, it would pay federal income tax on its income at the corporate tax rate, which is currently a maximum of 35%, and would pay state income taxes at varying rates. Under current law, distributions to unitholders, including us, would generally be taxed as a corporate distribution. Because a tax would be imposed upon Kinder Morgan Energy Partners as a corporation, the cash available for distribution to its unitholders, including us, would be substantially reduced.

In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon Kinder Morgan Energy Partners as an entity, the cash available for distribution to its unitholders would be reduced.

Competition could ultimately lead to lower levels of profits and adversely impact our ability to recontract for expiring transportation capacity at favorable rates. For the year ended December 31, 2006, NGPL's segment earnings represented approximately 32% of our total segment earnings plus net pre-tax impact of Kinder Morgan Energy Partners. NGPL is an interstate natural gas pipeline that is a major supplier to the Chicago, Illinois area. In the past, interstate pipeline competitors of NGPL have constructed or expanded pipeline capacity into the Chicago area. To the extent that an excess of supply into this market area is created and persists, NGPL's ability to recontract for expiring transportation capacity at favorable rates could be impaired. Contracts representing approximately 6.3% of NGPL's total long-haul, contracted firm transport capacity as of January 31, 2007 have not been renewed and are scheduled to expire before the end of 2007.

Trans Mountain's pipeline to the West Coast of North America and the Express System, in which we own an interest, to the U.S. Rocky Mountains and Midwest are two of several pipeline alternatives for Western Canadian petroleum production. These pipelines, like all our petroleum pipelines, compete against other pipeline companies who could be in a position to offer different tolling structures, which may provide them with a competitive advantage in new pipeline development. Throughput on our pipelines may decline if tolls become uncompetitive compared to alternatives.

Because electricity prices in British Columbia continue to be set based on the historical average cost of production, rather than based on market forces, they have remained artificially low compared to market-priced electricity and, as a result, only marginally higher than comparable, market-based natural gas costs. A sustained increase in natural gas commodity prices could cause natural gas in British Columbia to be uncompetitive with electricity, thereby decreasing the use of natural gas by Terasen Gas' customers.

The rates (which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for) we charge shippers on our natural gas pipeline systems and the rates our natural gas distribution operations can charge are subject to regulatory approval and oversight. While there are currently no material proceedings challenging the rates on any of our natural gas pipeline systems, regulators and shippers on these pipelines do have rights to challenge the rates they are charged under certain circumstances prescribed by applicable regulations. We can provide no assurance that we will not face challenges to the rates we receive on our pipeline systems in the future. Any successful challenge could materially adversely affect our future earnings and cash flows.

As part of the establishment of the rates which gas distribution operations can charge their customers, utility regulators, including the British Columbia Utilities Commission, or BCUC, generally establish a rate base and a reasonable and fair return for the utility upon that rate base. The allowed rates of return on our gas distribution operations are calculated differently and vary in amount in different jurisdictions. In British Columbia, the allowed rates of return on equity are determined annually by the BCUC based on a formula that applies a risk premium to a forecast of long-term Government of Canada bond yields. The allowed returns on equity for Terasen Gas Inc. and TGVI are determined by formulae that result in lower allowed returns on equity if long-term Government of Canada bond yields decline. Most rates in British Columbia are established using a future test year which has forecasts of the volume of gas that will be sold and transported and the costs, including the rate of return, that the utility will incur with cost and revenue tracking and sharing mechanisms that result in annual rate adjustments. Terasen Gas Inc. and TGVI have performance-based rate agreements expiring in 2007. There can be no assurance that new rate agreements will be entered into or that the regulatory process in which rates are determined will always produce rates that will result in full recovery of our British Columbia gas distribution operation's costs.

Pending Federal Energy Regulatory Commission and California Public Utilities Commission proceedings seek substantial refunds and reductions in tariff rates on some of Kinder Morgan Energy Partners' pipelines. If the proceedings are determined adversely to us, they could have a material adverse impact on us. Regulators and shippers on our pipelines have rights to challenge the rates Kinder Morgan Energy Partners charges under certain circumstances prescribed by applicable regulations. Some shippers on Kinder Morgan Energy Partners' pipelines have filed complaints with the Federal Energy Regulatory Commission and California Public Utilities Commission that seek substantial refunds for alleged overcharges during the years in question and prospective reductions in the tariff rates on Kinder Morgan Energy Partners' Pacific operations' pipeline system. Kinder Morgan Energy Partners may face challenges, similar to those described in Note 19 to our consolidated financial statements included elsewhere in this report, to the rates it receives on its pipelines in the future. Any successful challenge could adversely and materially affect our future earnings and cash flows.

Sustained periods of weather inconsistent with normal in areas served by our natural gas distribution operations can create volatility in our earnings. Our operating results may fluctuate on a seasonal basis. Weather-related factors such as temperature and rainfall at certain times of the year affect our earnings, principally in our retail natural gas distribution business. Sustained periods of temperatures and rainfall that differ from normal can create volatility in our earnings. In many areas, natural gas consumption patterns peak in the winter, especially for our retail natural gas distribution operations. Those operations normally generate higher net earnings in the first and fourth quarters, which are offset to some extent by lower earnings or net losses in the second and third quarters.

Proposed rulemaking by the FERC, the BCUC, the NEB or other regulatory agencies having jurisdiction could adversely impact our income and operations. Generally speaking, new laws or regulations or different interpretations of existing laws or regulations applicable to our assets could have a negative impact on our business, financial condition and results of operations.

Cost overruns and delays on our expansion and new build projects could adversely affect our business. We currently have several major expansion and new build projects planned or underway, including Kinder Morgan Energy Partners' approximate $4.4 billion Rockies Express Pipeline and approximate $1.25 billion Midcontinent Express Pipeline. A variety of factors outside our control, such as weather, natural disasters and difficulties in obtaining permits and rights-of-way or other regulatory approvals, as well as the performance by third party contractors, may result in increased costs or delays in construction. Cost overruns or delays in completing a project could have an adverse effect on our results of operations and cash flows.

Our rapid growth may cause difficulties integrating and constructing new operations, and we may not be able to achieve the expected benefits from any future acquisitions. Part of our business strategy includes acquiring additional businesses, expanding existing assets, or constructing new facilities. If we do not successfully integrate acquisitions, expansions, or newly constructed facilities, we may not realize anticipated operating advantages and cost savings. The integration of companies that have previously operated separately involves a number of risks, including:

- demands on management related to the increase in our size after an acquisition, an expansion, or a completed construction project;
- the diversion of our management's attention from the management of daily operations;
- difficulties in implementing or unanticipated costs of accounting, estimating, reporting and other systems;
- difficulties in the assimilation and retention of necessary employees; and
- potential adverse effects on operating results.

We may not be able to maintain the levels of operating efficiency that acquired companies have achieved or might achieve separately. Successful integration of each acquisition, expansion, or construction project will depend upon our ability to manage those operations and to eliminate redundant and excess costs. Because of difficulties in combining and expanding operations, we may not be able to achieve the cost savings and other size-related benefits that we hoped to achieve after these acquisitions, which would harm our financial condition and results of operations.

Environmental regulation and liabilities could result in increased operating and capital costs. Our business operations are subject to federal, state, provincial and local laws and regulations relating to environmental protection, pollution and human health and safety in the United States and Canada. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other products occurs at or from our pipelines, or at or from our storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to clean up the leak, release or spill, pay for government penalties, address natural resource damages, compensate for human exposure or property damage, install costly pollution control equipment, or a combination of these and other measures. The resulting costs and liabilities could negatively affect our level of earnings and cash flow. In addition, emission controls required under federal, state and provincial environmental laws could require significant capital expenditures at our facilities. The impact of environmental standards or future environmental measures could increase our costs significantly. The costs of environmental regulation are already significant, and additional or more stringent regulation could increase these costs or could otherwise negatively affect our business.

We own or operate numerous properties that have been used for many years in connection with our business activities. While we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other hazardous substances may have been released at or from properties owned, operated or used by us or our predecessors, or at or from properties where such wastes have been taken for disposal. In addition, many of these properties have been owned and/or operated by third parties whose management, use and disposal of hydrocarbons or other hazardous substances were not under our control. These properties and the hazardous substances released and wastes disposed thereon may be subject to laws in the United States such as the Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the Superfund law, which impose joint and several liability without regard to fault or the legality of the original conduct. Under the regulatory schemes of the various provinces, such as British Columbia's *Environmental Management Act*, Canada has similar laws with respect to properties owned, operated or used by us or our predecessors. Under such laws and implementing regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including groundwater contamination caused by prior owners or operators. Imposition of such liability schemes could have a material adverse impact on our operations and financial position.

In addition, Kinder Morgan Energy Partners' oil and gas development and production activities are subject to certain federal, state and local laws and regulations relating to environmental quality and pollution control. These laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Specifically, Kinder Morgan Energy Partners is subject to laws and regulations regarding the acquisition of permits before drilling, restrictions on drilling activities in restricted areas, emissions into the environment, water discharges, and storage and disposition of hazardous wastes. In addition, legislation has been enacted which requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. The costs of environmental regulation are already significant, and additional or more stringent regulation could increase these costs or could otherwise negatively affect our business.

Current or future distressed financial condition of customers could have an adverse impact on our operations in the event these customers are unable to pay us for the products or services we provide. Some of our customers are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their credit worthiness. We cannot provide assurance that one or more of our financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations, or future cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations and financial condition.

Increased regulatory requirements relating to the integrity of our pipelines will require us to spend additional money to comply with these requirements. Through our regulated pipeline subsidiaries, we are subject to extensive laws and regulations related to pipeline integrity. There are, for example, federal guidelines for the U.S. Department of Transportation and pipeline companies in the areas of testing, education, training and communication. We have increased our capital expenditures to address these matters and expect to significantly increase these expenditures in the foreseeable future. Additional laws and regulations that may be enacted in the future could significantly increase the amount of these expenditures.

Future business development of our products pipelines is dependent on the supply of, and demand for, crude oil and other liquid hydrocarbons, particularly from the Alberta oilsands. Our pipelines depend on production of natural gas, oil and other products in the areas serviced by its pipelines. Without reserve additions, production will decline over time as reserves are depleted and production costs may rise. Producers may shut down production at lower product prices or higher production costs, especially where the existing cost of production exceeds other extraction methodologies, such as at the Alberta oilsands. Producers in areas serviced by us may not be successful in exploring for and developing additional reserves, and the gas plants and the pipelines may not be able to maintain existing volumes of throughput. Commodity prices and tax incentives may not remain at a level which encourages producers to explore for and develop additional reserves, produce existing marginal reserves or renew transportation contracts as they expire.

Changes in the business environment, such as a decline in crude oil prices, an increase in production costs from higher feedstock prices, supply disruptions, or higher development costs, could result in a slowing of supply from the Alberta oilsands. In addition, changes in the regulatory environment or governmental policies may have an impact on the supply of crude oil. Each of these factors impact our customers shipping through our pipelines, which in turn could impact the prospects of new transportation contracts or renewals of existing contracts.

Throughput on our products pipelines may also decline as a result of changes in business conditions. Over the long term, business will depend, in part, on the level of demand for oil and natural gas in the geographic areas in which deliveries are made by pipelines and the ability and willingness of shippers having access or rights to utilize the pipelines to supply such demand. The implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for natural gas and crude oil, increase our costs and may have a material adverse effect on our results of operations and financial condition. We cannot predict the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce the demand for natural gas and oil.

We are subject to U.S. dollar/Canadian dollar exchange rate fluctuations. As a result of our acquisition of Terasen, a significant portion of our assets, liabilities, revenues and expenses are denominated in Canadian dollars. We are a U.S. dollar reporting company. Fluctuations in the exchange rate between United States and Canadian dollars could expose us to reductions in the U.S. dollar value of our earnings and cash flows and a reduction in our stockholders' equity under applicable accounting rules.

The future success of Kinder Morgan Energy Partners' oil and gas development and production operations depends in part upon its ability to develop additional oil and gas reserves that are economically recoverable. The rate of production from oil and natural gas properties declines as reserves are depleted. Without successful development activities, the reserves and revenues of Kinder Morgan Energy Partners' CO_2 business segment will decline. Kinder Morgan Energy Partners may not be able to develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities in the future.

The development of oil and gas properties involves risks that may result in a total loss of investment. The business of developing and operating oil and gas properties involves a high degree of business and financial risk that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Acquisition and development decisions generally are based on subjective judgments and assumptions that are speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, a successful completion of a well does not ensure a profitable return on the investment. A variety of geological, operational, or market-related factors, including, but not limited to, unusual or unexpected geological formations, pressures, equipment failures or accidents, fires, explosions, blowouts, cratering, pollution and other environmental risks, shortages or delays in the availability of drilling rigs and the delivery of equipment, loss of circulation of drilling fluids or other conditions may substantially delay or prevent completion of any well, or otherwise prevent a property or well from being profitable. A productive well may become uneconomic in the event water or other deleterious substances are encountered, which impair or prevent the production of oil and/or gas from the well. In addition, production from any well may be unmarketable if it is contaminated with water or other deleterious substances.

The volatility of natural gas and oil prices could have a material adverse effect on our business. The revenues, profitability and future growth of Kinder Morgan Energy Partners' CO_2 business segment and the carrying value of its oil and natural gas properties depend to a large degree on prevailing oil and gas prices. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include, among other things, weather conditions and events such as hurricanes in the United States; the condition of the United States economy; the activities of the Organization of Petroleum Exporting Countries; governmental regulation; political stability in the Middle East and elsewhere; the foreign supply of oil and natural gas; the price of foreign imports; and the availability of alternative fuel sources.

A sharp decline in the price of natural gas or oil prices would result in a commensurate reduction in our revenues, income and cash flows from the production of oil and natural gas and could have a material adverse effect on the carrying value of Kinder Morgan Energy Partners' proved reserves. In the event prices fall substantially, Kinder Morgan Energy Partners may not be able to realize a profit from its production and would operate at a loss. In recent decades, there have been periods of both worldwide overproduction and underproduction of hydrocarbons and periods of both increased and relaxed energy conservation efforts. Such conditions have resulted in periods of excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. These periods have been followed by periods of short supply of, and increased demand for, crude oil and natural gas. The excess or short supply of crude oil or natural gas has placed pressures on prices and has resulted in dramatic price fluctuations even during relatively short periods of seasonal market demand.

Our use of hedging arrangements could result in financial losses or reduce our income. We currently engage in hedging arrangements to reduce our exposure to fluctuations in the prices of oil and natural gas. These hedging arrangements expose us to risk of financial loss in some circumstances, including when production is less than expected, when the counterparty to the hedging contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the hedging agreement and the actual prices received. In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in prices for oil and natural gas.

The accounting standards regarding hedge accounting are very complex, and even when we engage in hedging transactions (for example, to mitigate our exposure to fluctuations in commodity prices or currency exchange rates or to balance our exposure to fixed and floating interest rates) that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at that point. In addition, it is not always possible for us to engage in a hedging transaction that completely mitigates our exposure to commodity prices. Our financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 3. ***Legal Proceedings.***

The reader is directed to Note 19 of the accompanying Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Item 4. ***Submission of Matters to a Vote of Security Holders.***

We held a special meeting of shareholders on December 19, 2006 to vote on a proposal to approve and adopt the Agreement and Plan of Merger among Kinder Morgan, Inc., Knight Holdco LLC and Knight Acquisition Co., as it may be amended from time to time. The matter was unanimously approved and recommended by our board of directors (with the three directors who are participating as rollover investors in the transaction contemplated in the merger agreement taking no part in the deliberations).

With respect to the proposal, the vote was as follows:

For	97,275,863
Against	1,827,306
Abstain	916,573
Broker Non-votes	N/A

This proposal was approved as it received the affirmative vote of the holders of at least two-thirds of all our common stock entitled to vote at the special meeting.

PART II

Item 5. *Market for Registrant's Common Eq uity, Related Stockholder Matters and Issuer Purchases of Equity Securities.*

Our common stock is listed for trading on the New York Stock Exchange under the symbol "KMI." Dividends paid and the high and low sale prices per share, as reported on the New York Stock Exchange, of our common stock by quarter for the last two years are provided below. In January 2006, we increased our quarterly common dividend to $0.875 per share.

	Market Price Per Share			
	2006		2005	
	Low	High	Low	High
Quarter Ended:				
March 31	$89.13	$103.75	$69.27	$81.57
June 30	$81.00	$103.00	$72.49	$83.97
September 30	$99.50	$105.00	$81.82	$99.97
December 31	$104.00	$106.20	$84.10	$96.28

	Dividends Paid Per Share	
	2006	2005
Quarter Ended:		
March 31	$0.8750	$0.7000
June 30	$0.8750	$0.7000
September 30	$0.8750	$0.7500
December 31	$0.8750	$0.7500

Stockholders as of February 1, 2007................................ 71,000 (approximately)

There were no sales of unregistered equity securities during the period covered by this report.

For information regarding our equity compensation plans, please refer to Item 12, included elsewhere herein.

Our Purchases of Our Common Stock

Period	Total Number of Shares Purchased[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[1]	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 to October 31, 2006	–	$ –	–	$ 18,203,665
November 1 to November 30, 2006	–	$ –	–	$ 18,203,665
December 1 to December 31, 2006	–	$ –	–	$ 18,203,665
Total	–	$ –	–	$ 18,203,665

[1] On August 14, 2001, we announced a plan to repurchase $300 million of our outstanding common stock, which program was increased to $400 million, $450 million, $500 million, $550 million, $750 million, $800 million and $925 million in February 2002, July 2002, November 2003, April 2004, November 2004, April 2005 and November 2005, respectively.

Item 6. ***Selected Financial Data.***

Five-Year Review[1]
Kinder Morgan, Inc. and Subsidiaries

	Year Ended December 31,				
	2006[2,3,4]	2005[3]	2004	2003	2002
	(In millions except per share amounts)				
Operating Revenues	$ 11,846.4	$ 1,254.5	$ 877.7	$ 848.8	$ 755.5
Gas Purchases and Other Costs of Sales	7,318.1	458.8	194.2	232.1	164.7
Other Operating Expenses[5]	3,142.1	371.8	342.5	316.5	397.8
Operating Income	1,386.2	423.9	341.0	300.2	193.0
Other Income and (Expenses)	(1,063.4)	451.5	365.2	281.5	214.4
Income from Continuing Operations Before Income Taxes	322.8	875.4	706.2	581.7	407.4
Income Taxes	274.1	345.5	208.0	225.1	121.8
Income from Continuing Operations	48.7	529.9	498.2	356.6	285.6
Gain (Loss) from Discontinued Operations, Net of Tax	23.2	24.7	23.9	25.1	17.1
Net Income	$ 71.9	$ 554.6	$ 522.1	$ 381.7	$ 302.7
Basic Earnings (Loss) Per Common Share:					
Continuing Operations	$ 0.37	$ 4.29	$ 4.03	$ 2.91	$ 2.34
Discontinued Operations	0.17	0.20	0.19	0.20	0.14
Total Basic Earnings Per Common Share	0.54	$ 4.49	$ 4.22	$ 3.11	$ 2.48
Number of Shares Used in Computing Basic Earnings (Loss) Per Common Share	133.0	123.5	123.8	122.6	122.2
Diluted Earnings (Loss) Per Common Share:					
Continuing Operations	$ 0.36	$ 4.25	$ 3.99	$ 2.88	$ 2.31
Discontinued Operations	0.17	0.20	0.19	0.20	0.14
Total Diluted Earnings Per Common Share	$ 0.53	$ 4.45	$ 4.18	$ 3.08	$ 2.45
Number of Shares Used in Computing Diluted Earnings (Loss) Per Common Share	135.0	124.6	124.9	123.8	123.4
Dividends Per Common Share	$ 3.50	$ 2.90	$ 2.25	$ 1.10	$ 0.30
Capital Expenditures[6]	1,583.1	$ 144.5	$ 103.2	$ 132.0	$ 149.6

1 Includes significant impacts from acquisitions and dispositions of assets. See Notes 1(Q), 4 and 5 of the accompanying Notes to Consolidated Financial Statements for information regarding dispositions during 2006, 2005, and 2004.

2 Due to our adoption of EITF No. 04-5, effective January 1, 2006 the accounts, balances and results of operations of Kinder Morgan Energy Partners are included in our financial statements and we no longer apply the equity method of accounting to our investments in Kinder Morgan Energy Partners. See Note 1(B) of the accompanying Notes to Consolidated Financial Statements.

3 Includes the results of Terasen Inc. subsequent to its November 30, 2005 acquisition by us. See Note 4 of the accompanying Notes to Consolidated Financial Statements for information regarding this acquisition.

4 Includes results of operations for the oil and gas properties acquired by Kinder Morgan Energy Partners from Journey Acquisition-I, L.P. and Journey 2000, L.P., the terminal assets and operations acquired by Kinder Morgan Energy Partners from A&L Trucking, L.P. and U.S. Development Group, Transload Services, LLC, and Devco USA L.L.C. since effective dates of acquisition. The April 5, 2006 acquisition of the Journey oil and gas properties were made effective March 1, 2006. The assets and operations acquired from A&L Trucking and U.S. Development Group were acquired in three separate transactions in April 2006. Kinder Morgan Energy Partners acquired all of the membership interests in Transload Services, LLC effective November 20, 2006, and they acquired all of the membership interests in Devco USA L.L.C. effective December 1, 2006. Kinder Morgan Energy Partners also acquired a 66 2/3% ownership interest in Entrega Pipeline LLC effective February 23, 2006, however, its earnings were not materially impacted during 2006 due to the fact that regulatory accounting provisions required capitalization of revenues and expenses until the second segment of the Entrega Pipeline is complete and in-service.

5 Includes a charge of $650.5 million in 2006 to reduce the carrying value of Terasen Gas. Also includes charges of $1.2 million, $6.5 million, $33.5 million, $44.5 million and $134.5 million in 2006, 2005, 2004, 2003 and 2002, respectively, to reduce the carrying value of certain power assets; see Note 6 of the accompanying Notes to Consolidated Financial Statements.

6 Capital Expenditures shown are for continuing operations only.

Five-Year Review (Continued)
Kinder Morgan, Inc. and Subsidiaries

	As of December 31,									
	2006[1,2]		2005[2]		2004		2003		2002	
	(In millions except per share amounts)									
Total Assets	$ 26,795.6		$ 17,451.6		$ 10,116.9		$ 10,036.7		$ 10,102.8	
Capitalization:										
Common Equity[3]	$ 3,657.5	20%	$ 4,051.4	34%	$ 2,919.5	45%	$ 2,691.8	39%	$ 2,399.7	37%
Deferrable Interest Debentures[4]	283.6	2%	283.6	2%	283.6	4%	283.6	4%	-	-
Capital Securities	106.9	1%	107.1	1%	-	-	-	-	-	-
Preferred Capital Trust Securities[4]	-	-	-	-	-	-	-	-	275.0	4%
Minority Interests	3,095.5	17%	1,247.3	10%	1,105.4	17%	1,010.1	15%	967.8	15%
Outstanding Notes and Debentures[5]	10,623.9	60%	6,286.8	53%	2,258.0	34%	2,837.5	42%	2,852.2	44%
Total Capitalization	$ 17,767.4	100%	$ 11,976.2	100%	$ 6,566.5	100%	$ 6,823.0	100%	$ 6,494.7	100%
Book Value Per Common Share	$ 26.25		$ 29.34		$ 23.19		$ 21.62		$ 19.35	

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[1] Due to our adoption of EITF No. 04-5, effective January 1, 2006 the accounts, balances and results of operations of Kinder Morgan Energy Partners are included in our financial statements and we no longer apply the equity method of accounting to our investments in Kinder Morgan Energy Partners. See Note 1(B) of the accompanying Notes to Consolidated Financial Statements.

[2] Reflects the acquisition of Terasen Inc. on November 30, 2005. See Note 4 of the accompanying Notes to Consolidated Financial Statements for information regarding this acquisition.

[3] Excludes Accumulated Other Comprehensive Income/Loss.

[4] As a result of our adoption of FASB Interpretation No. 46 (Revised December 2003), Consolidation of Variable Interest Entities, the subsidiary trusts associated with these securities are no longer consolidated, effective December 31, 2003.

[5] Excludes the value of interest rate swaps and short-term debt. See Note 12 of the accompanying Notes to Consolidated Financial Statements.

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

General

In this report, unless the context requires otherwise, references to "we," "us," "our," or the "Company" are intended to mean Kinder Morgan, Inc. and its consolidated subsidiaries. Further, unless the context requires otherwise, references to "Kinder Morgan Energy Partners" are intended to mean Kinder Morgan Energy Partners, L.P., a publicly traded pipeline master limited partnership in which we own the general partner interest and significant limited partner interests, and its consolidated subsidiaries. The following discussion should be read in conjunction with the accompanying Consolidated Financial Statements and related Notes. Specifically, as discussed in Note 1(B) of the accompanying Notes to Consolidated Financial Statements, due to our adoption of EITF No. 04-5, effective as of January 1, 2006, Kinder Morgan Energy partners and its consolidated subsidiaries are included as consolidated subsidiaries of Kinder Morgan, Inc. in our consolidated financial statements. Accordingly, their accounts, balances and results of operations are included in our consolidated financial statements for periods beginning on and after January 1, 2006, and we no longer apply the equity method of accounting to our investment in Kinder Morgan Energy Partners. Notwithstanding the consolidation of Kinder Morgan Energy Partners and its subsidiaries into our financial statements pursuant to EITF 04-5, we are not liable for, and our assets are not available to satisfy, the obligations of Kinder Morgan Energy Partners and/or its subsidiaries and vice versa. Responsibility for payments of obligations reflected in our or Kinder Morgan Energy Partners' financial statements is a legal determination based on the entity that incurs the liability. The determination of responsibility for payment among entities in our consolidated group of subsidiaries was not impacted by the adoption of EITF 04-5. As discussed in Note 4 of the accompanying Notes to Consolidated Financial Statements, we acquired Terasen Inc., referred to in this report as Terasen, on November 30, 2005. In August 2006, we entered into a definitive agreement with a subsidiary of General Electric Company to sell our U.S. retail natural gas distribution and related operations for $710 million plus working capital. In prior periods, we referred to these operations as the Kinder Morgan Retail business segment. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* the financial results of these operations have been reclassified to discontinued operations for all periods presented. Refer to the heading "Discontinued Operations" included elsewhere in management's discussion and analysis for additional information regarding discontinued operations. In February 2007, we entered into a definitive agreement to sell our Canada-based retail natural gas operations, and as a result we recorded an estimated goodwill impairment charge of approximately $650.5 million in the fourth quarter of 2006. Our adoption of EITF No. 04-5, our acquisition of Terasen, the reclassification of the financial results of our U.S. retail natural gas distribution and related operations, the impairment of goodwill described above and other acquisitions and divestitures (including the transfer of certain assets to Kinder Morgan Energy Partners) discussed in Notes 4, 5, 6, 7 and 21 of the accompanying Notes to Consolidated Financial Statements affect comparisons of our financial position and results of operations between periods.

To convert December 31, 2006 balances denominated in Canadian dollars to U.S. dollars, we used the December 31, 2006 Bank of Canada closing exchange rate of 0.8581 U.S. dollars per Canadian dollar.

We are an energy infrastructure provider through our direct ownership and operation of energy-related assets, and through our ownership interests in and operation of Kinder Morgan Energy Partners. As described in "Business Strategy" under Items 1 and 2 "Business and Properties" elsewhere in this report, our strategy and focus continues to be on ownership of fee-based energy-related assets which are core to the energy infrastructure of North America and serve growing markets. These assets tend to have relatively stable cash flows while presenting us with opportunities to expand our facilities to serve additional customers and nearby markets. We evaluate the performance of our investment in these assets using, among other measures, segment earnings. In addition, please see "Recent Developments" under Items 1 and 2 "Business and Properties" elsewhere in this report.

The variability of our operating results is attributable to a number of factors including (i) variability within U.S. and Canadian national and local markets for energy and related services, including the effects of competition, (ii) the impact of regulatory proceedings, (iii) the effect of weather on customer energy and related services usage, as well as our operation and construction activities, (iv) increases or decreases in interest rates, (v) the degree of our success in controlling costs and identifying, carrying out profitable expansion projects and integrating new acquisitions into our operations and (vi) changes in taxation policy or regulated rates. Certain of these factors are beyond our direct control, but we operate a structured risk management program to mitigate certain of the risks associated with changes in the price of natural gas, interest rates, currency exchange rates and weather (relative to historical norms). The remaining risks are primarily mitigated through our strategic and operational planning and monitoring processes. See Item 1A "Risk Factors" elsewhere in this report.

Critical Accounting Policies and Estimates

Our discussion and analysis of financial condition and results of operations are based on our consolidated financial statements, prepared in accordance with accounting principles generally accepted in the United States of America and contained within this report. Certain amounts included in or affecting our financial statements and related disclosure must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time the financial statements are prepared. The reported amounts of our assets and liabilities, revenues and expenses and associated disclosures with respect to contingent assets and obligations are necessarily affected by these estimates. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates.

In preparing our financial statements and related disclosures, we must use estimates in determining the economic useful lives of our assets, the effective income tax rate to apply to our pre-tax income, deferred income tax assets, deferred income tax liabilities, obligations under our employee benefit plans, provisions for uncollectible accounts receivable, unbilled revenues for our natural gas distribution deliveries for which meters have not yet been read, cost and timing of environmental remediation efforts, the fair values used to allocate purchase price and to determine possible asset impairment charges, potential exposure to adverse outcomes from judgments, litigation settlements or transportation rate cases, exposures under contractual indemnifications, and various other recorded or disclosed amounts. Certain of these accounting estimates are of more significance in our financial statement preparation process than others.

Environmental Matters

With respect to our environmental exposure, we utilize both internal staff and external experts to assist us in identifying environmental issues and in estimating the costs and timing of remediation efforts. We expense or capitalize, as appropriate, environmental expenditures that relate to current operations, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. We do not discount environmental liabilities to a net present value, and we recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable.

The recording of environmental accruals often coincides with the completion of a feasibility study or the commitment to a formal plan of action, but generally, we recognize and/or adjust our environmental liabilities following routine reviews of potential environmental issues and claims that could impact our assets or operations.

In 2006, we made quarterly adjustments to our environmental liabilities to reflect changes in previous estimates. In addition to quarterly reviews of potential environmental issues and resulting environmental liability adjustments, we made supplemental liability adjustments in 2006 that were primarily related to newly identified and/or recently incurred environmental issues and claims, largely related to refined petroleum products pipeline releases of Kinder Morgan Energy Partners and Plantation Pipe Line Company. These supplemental environmental liability adjustments were recorded pursuant to management's requirement to recognize contingent environmental liabilities whenever the associated environmental issue is likely to occur and the amount of our liability can be reasonably estimated. In making these liability estimations, we considered the effect of environmental compliance, pending legal actions against us, and potential third-party liability claims.

As a result, in 2006, Kinder Morgan Energy Partners recorded a combined $35.4 million expense associated with total environmental liability adjustments, including a $17.9 million expense associated with supplemental liability adjustments. The total environmental expense adjustments (including Kinder Morgan Energy Partners' share of environmental expense associated with liability adjustments recognized by Plantation Pipe Line Company) included a $4.1 million increase in Kinder Morgan Energy Partners' estimated environmental receivables and reimbursables, a $3.5 million decrease in Kinder Morgan Energy Partners' equity investments, a $34.5 million increase in Kinder Morgan Energy Partners' overall accrued environmental and related claim liabilities, and a $1.5 million increase in Kinder Morgan Energy Partners' accrued expense liabilities.

The $17.9 million Kinder Morgan Energy Partners expense related to supplemental environmental liability adjustments resulted in a $16.4 million increase in expense to the Products Pipelines – KMP business segment and a $1.5 million increase in expense to the Natural Gas Pipelines – KMP business segment. It consisted of a $14.9 million expense recorded within "Operations and Maintenance," a $4.9 million expense recorded within "Equity in Earnings of Other Equity Investments," and a $1.9 million reduction in expense recorded within "Income Taxes" in the accompanying Consolidated Statement of Operations for 2006.

Regulatory and Legal Matters

Our regulated utility operations are accounted for in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation*. As a result, we record assets and liabilities that result from the ratemaking process that would not be recorded under GAAP for non-regulated entities. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. The accounting for these items is based on an expectation of the future decisions or approvals of the regulator. The deferral of differences between amounts included in tolls or rates and actual experience for specified expenses is based on the expectation that the regulator will approve the refund to or recovery from customers of the deferred balance. If the regulators' future actions are different from our expectations, the timing and amount of the recovery of assets or refund of liabilities could be substantially different from that reflected in the financial statements. When assessing whether our regulatory assets and liabilities are probable of future recovery or refund, we consider such factors as changes in the regulatory environment, recent rate orders to other regulated utilities, and the status of any pending deregulation legislation. While we believe the existing regulatory assets are probable of recovery, the current regulatory and political climate on which this assessment is based is subject to change in the future. We are subject to litigation and regulatory proceedings as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. To the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. We expense legal costs as incurred, and all recorded legal liabilities are revised as better information becomes available.

SFPP, L.P. is the subsidiary limited partnership that owns Kinder Morgan Energy Partners' Pacific operations' pipelines, excluding CALNEV Pipe Line LLC. Tariffs charged by the Pacific operations' pipeline systems are subject to certain proceedings at the Federal Energy Regulatory Commission ("FERC") involving shippers' complaints regarding the interstate rates, as well as practices and the jurisdictional nature of certain facilities and services. Generally, the interstate rates on the Pacific operations' pipeline systems are "grandfathered" under the Energy Policy Act of 1992 unless "substantially changed circumstances" are found to exist. To the extent "substantially changed circumstances" are found to exist, the Pacific operations may be subject to substantial exposure under these FERC complaints and could, therefore, owe reparations and/or refunds to complainants as mandated by the FERC or the United States' judicial system.

In December 2005, Kinder Morgan Energy Partners recorded an accrual of $105.0 million for an expense attributable to an increase in the reserves related to its rate case liability. The factors we considered when making this additional accrual included, among others: (i) the opinions and views of our legal counsel; (ii) our experience with reparations and refunds previously paid to complainants and other shippers as required by the FERC (in 2003, Kinder Morgan Energy Partners paid transportation rate reparation and refund payments in the amount of $44.9 million as mandated by the FERC); and (iii) the decision of management as to how we intended to respond to the complaints, which included the compliance filing submitted to the FERC on March 7, 2006.

In accordance with the FERC's December 2005 Order and February 2006 Order on Rehearing, rate reductions were implemented by Kinder Morgan Energy Partners on May 1, 2006. We assume that reparations and accrued interest thereon will be paid no earlier than the second quarter of 2007; however, the timing and nature of any rate reductions and reparations that may be ordered will likely be affected by the final disposition of the application of the FERC's new policy statement on income tax allowances to Kinder Morgan Energy Partners' Pacific operations in FERC Docket Nos. OR92-8, OR96-2, and IS05-230 proceedings.

Kinder Morgan Energy Partners had previously estimated the combined annual impact of the rate reductions and the payment of reparations sought by shippers would be approximately 15 cents of distributable cash flow per unit. Based on our review of the December 2005 and the February 2006 Orders, and subject to the ultimate resolution of these issues in SFPP's compliance filings and subsequent judicial appeals, we now expect the total annual impact on Kinder Morgan Energy Partners will be less than 15 cents per unit. We estimate that the actual, partial year impact on Kinder Morgan Energy Partners' 2006 distributable cash flow was approximately $15.7 million and the partial year impact on our 2006 earnings per share was approximately $0.04 per share.

In addition, the third quarter of 2006, Kinder Morgan Energy Partners made refund payments of $19.1 million to certain shippers on the Pacific operations' pipelines and Kinder Morgan Energy Partners reduced its rate case liability. The payment related to a settlement agreement reached in May 2006 that resolved certain challenges by complainants with regard to delivery tariffs and gathering enhancement fees at the Pacific operations' Watson Station, located in Carson, California.

For more information regarding the Pacific operations' regulatory proceedings, see Note 19 of the accompanying Notes to Consolidated Financial Statements.

Intangible Assets

Intangible assets are those assets which provide future economic benefit but have no physical substance. We account for our intangible assets according to the provisions of Statement of Financial Accounting Standards ("SFAS") No. 141, *Business Combinations* and SFAS No. 142, *Goodwill and Other Intangible Assets*. These accounting pronouncements introduced the concept of indefinite life intangible assets and provided that all identifiable intangible assets having indefinite useful economic lives, including goodwill, will not be subject to regular periodic amortization. Such assets are not to be amortized until their lives are determined to be finite. Instead, the carrying amount of a recognized intangible asset with an indefinite useful life must be tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. In accordance with the provisions of SFAS No. 142, we test our goodwill for impairment on an annual basis, and have determined that, with the exception of the goodwill associated with Terasen Gas (see Note 6 of the accompanying Notes to Consolidated Financial Statements), our goodwill is not impaired.

Our remaining intangible assets, excluding goodwill, include lease value, contracts, customer relationships, technology-based assets and agreements. These intangible assets have definite lives, are being amortized on a straight-line basis over their estimated useful lives, and are reported separately as "Other Intangibles, Net" in the accompanying Consolidated Balance Sheets. As of December 31, 2006, these intangibles totaled $229.5 million.

Estimated Net Recoverable Quantities of Oil and Gas

We use the successful efforts method of accounting for Kinder Morgan Energy Partners' oil and gas producing activities. The successful efforts method inherently relies on the estimation of proved reserves, both developed and undeveloped. The existence and the estimated amount of proved reserves affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depleted or amortized into income and the presentation of supplemental information on oil and gas producing activities. The expected future cash flows to be generated by oil and gas producing properties used in testing for impairment of such properties also rely in part on estimates of net recoverable quantities of oil and gas.

Proved reserves are the estimated quantities of oil and gas that geologic and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves may change, either positively or negatively, as additional information becomes available and as contractual, economic and political conditions change.

Hedging Activities

As discussed under "Risk Management" in Item 7A of this report, we enter into derivative contracts (natural gas futures, swaps and options) solely for the purpose of mitigating risks that accompany our normal business activities, including fluctuations in foreign currency exchange, interest rates and the price of natural gas and associated transportation. We account for these derivative transactions as hedges in accordance with authoritative accounting guidelines, marking the derivatives to market at each reporting date. At December 31, 2006, the majority of our derivative financial instruments either (i) met specific hedge accounting criteria whereby the unrealized gains and losses are either recognized as part of comprehensive income or, in the case of interest rate swaps, as a valuation adjustment to the underlying debt, or (ii) related to regulated business activities where the risk is passed through to customers and accordingly the unrealized gains and losses are deferred until recovered or refunded to customers through rates. Unrealized gains or losses of derivative financial instruments that do not meet specific hedge accounting criteria or do not have the risk passed through to customers are recognized in income currently. Any inefficiency in the performance of the hedge is recognized in income currently or as appropriate, deferred in regulatory accounts and, ultimately, the financial results of the hedge are recognized concurrently with the financial results of the underlying hedged item. All but an insignificant amount of our natural gas related derivatives are for terms of 18 months or less, allowing us to utilize widely available, published forward pricing curves in determining all of our appropriate market values. Our interest rate swaps are similar in nature to many other such financial instruments and are valued for us by commercial banks with expertise in such valuations.

We engage in a hedging program to mitigate our exposure to fluctuations in currency exchange rates and commodity prices and to balance our exposure to fixed and floating interest rates, and we believe that these hedges are generally effective in realizing these objectives. However, the accounting standards regarding hedge accounting are complex, and even when we engage in hedging transactions that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at that point. Generally, the financial statement volatility arises from an accounting requirement to recognize changes in values of financial instruments while not concurrently recognizing the values of the underlying transactions being hedged.

In addition, it is not always possible for us to engage in a hedging transaction that completely mitigates our exposure to commodity prices. For example, when we purchase a commodity at one location and sell it at another, we may be unable to hedge completely our exposure to a differential in the price of the product between these two locations. Even when we cannot enter into a completely effective hedge, we often enter into hedges that are not completely effective in those instances where we believe to do so would be better than not hedging at all. Our financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge.

Cycle Billing

In our retail natural gas distribution business (which, for our U.S.-based operations, has been reclassified to discontinued operations for all periods presented as discussed in Note 7 of the accompanying Notes to Consolidated Financial Statements), because we read customer meters on a cycle basis, we are required to estimate the amount of revenue earned as of the end of each period for which service has been rendered but meters have not yet been read. We have historical information available for these meters and, together with weather-related data that is indicative of natural gas demand, we are able to make reasonable estimates. In our natural gas pipeline businesses, we are similarly required to make estimates for services rendered but for which actual metered volumes are not available at reporting dates. As with our retail natural gas distribution business, we have historical data available to assist us in the estimation process, but the variations in volume are greater, introducing a larger possibility of error. We believe that our estimates, which are replaced with actual metered volumes in the next accounting month, provide acceptable approximations of the actual revenue earned during any period, especially given that the majority of our revenues in the pipeline business are derived from demand charges, which do not vary with the actual amount of gas transported.

Employee Benefit Plans

With respect to the amount of income or expense we recognize in association with our pension and retiree medical plans, we must make a number of assumptions with respect to both future financial conditions (for example, medical costs, returns on fund assets and market interest rates) as well as future actions by plan participants (for example, when they will retire and how long they will live after retirement). Most of these assumptions have relatively minor impacts on the overall accounting recognition given to these plans, but two assumptions in particular, the discount rate and the assumed long-term rate of return on fund assets, can have significant effects on the amount of expense recorded and liability recognized. We review historical trends, future expectations, current and projected market conditions, the general interest rate environment and benefit payment obligations to determine the assumptions. The discount rate represents the market rate for a high quality corporate bond. The selection of these assumptions is discussed in Note 13 of the accompanying Notes to Consolidated Financial Statements. While we believe our choices for these assumptions are appropriate in the circumstances, other assumptions could also be reasonably applied and, therefore, we note that, at our current level of pension and retiree medical funding (excluding the pension and retiree medical plans of Terasen and without adjustment for the change in these amounts that would be attributable to the expected disposition of our U.S.-based natural gas distribution operations), a change of 1% in the long-term return assumption would increase (decrease) our annual retiree medical expense by approximately $642,000 ($642,000) and would increase (decrease) our annual pension expense by $2.4 million ($2.4 million) in comparison to that recorded in 2006. Similarly, and without adjustment for the expected disposition of our U.S.-based natural gas distribution operations as discussed preceding, a 1% change in the discount rate would increase (decrease) our accumulated postretirement benefit obligation by $7.3 million ($6.6 million) and would increase (decrease) our projected pension benefit obligation by $28.9 million ($25.6 million) compared to those balances as of December 31, 2006.

Terasen's postretirement benefit programs are unfunded, and therefore there is no impact to expense from a change in the long-term return assumptions. Terasen's defined benefit pension programs are funded, but due to the significance of the regulated operations, the impact on expense of variances in long-term return assumptions and discount rates is materially recovered through rate-setting mechanisms. Terasen's supplemental pension plans are unfunded and are therefore not subject to variances in long-term return assumptions. A 1% change in the discount rate would increase (decrease) Terasen's accumulated postretirement benefit obligation by $12.5 million ($10.7 million) and its projected pension benefit obligation by $28.5 million ($50.9 million) compared to those balances as of December 31, 2006.

Income Taxes

We record a valuation allowance to reduce our deferred tax assets to an amount that is more likely than not to be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached. In addition, we do business in a number of states with differing laws concerning how income subject to each state's tax structure is measured and at what effective rate such income is taxed. Therefore, we must make estimates of how our income will be apportioned among the various states in order to arrive at an overall effective tax rate. Changes in our effective rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

Consolidated Financial Results

	Year Ended December 31,		
	2006[1, 2]	2005[1]	2004
	(In millions except per share amounts)		
Equity in Earnings of Kinder Morgan Energy Partners[2, 3]	$ –	$ 605.4	$ 558.1
Segment Earnings:[4]			
NGPL[5]	499.0	435.2	392.8
Terasen Gas	312.9	45.2	–
Kinder Morgan Canada	119.9	12.5	–
Power	21.1	19.7	15.3
Products Pipelines – KMP	404.9	–	–
Natural Gas Pipelines – KMP	509.1	–	–
CO_2 – KMP	295.2	–	–
Terminals – KMP	333.6	–	–
TransColorado	–	–	20.3
Total Segment Earnings	2,495.7	1,118.0	986.5
Impairment of Assets[7, 8, 9]	(651.7)	(6.5)	(33.5)
Interest and Other Corporate Expenses, Net[6, 7, 8, 9]	(1,540.2)	(236.1)	(246.8)
Income From Continuing Operations Before Income Taxes[4]	303.8	875.4	706.2
Income Taxes[4, 10, 11]	(255.1)	(345.5)	(208.0)
Income From Continuing Operations[12]	48.7	529.9	498.2
Income (Loss) From Discontinued Operations, Net of Tax	23.2	24.7	23.9
Net Income	$ 71.9	$ 554.6	$ 522.1
Diluted Earnings (Loss) Per Common Share:			
Income From Continuing Operations	$ 0.36	$ 4.25	$ 3.99
Income (Loss) From Discontinued Operations	0.17	0.20	0.19
Total Diluted Earnings Per Common Share	$ 0.53	$ 4.45	$ 4.18
Number of Shares Used in Computing Diluted Earnings Per Common Share	135.0	124.6	124.9

1 Operating results for 2006 and 2005 include the results of Terasen, which we acquired on November 30, 2005. See Note 4 of the accompanying Notes to Consolidated Financial Statements. Certain of these assets are subject to a February 2007 definitive sales agreement, see Note 21 of the accompanying Notes to Consolidated Financial Statements.

2 Due to our adoption of EITF No. 04-5, effective January 1, 2006 the accounts, balances and results of operations of Kinder Morgan Energy Partners are included in our financial statements and we no longer apply the equity method of accounting to our investment in Kinder Morgan Energy Partners. See Note 1(B) of the accompanying Notes to Consolidated Financial Statements.

3 Equity in Earnings of Kinder Morgan Energy Partners for 2005 includes a reduction in pre-tax earnings of approximately $63.3 million ($40.3 million after tax) resulting principally from the effects of certain regulatory, environmental, litigation and inventory items on Kinder Morgan Energy Partners' earnings.

4 Segment earnings includes operating income before corporate costs plus earnings from equity method investments plus gains and losses on incidental sales of assets. In 2006, for our business segments that are also segments of Kinder Morgan Energy Partners, also includes interest income, other, net and an aggregate of $19.0 million of income taxes allocated to the segments.

5 Results for 2005 include a pre-tax loss of $1.7 million ($1.1 million after tax) incurred for hedge ineffectiveness.

6 Includes (i) general and administrative expenses, (ii) interest expense, (iii) minority interests and (iv) other, net.

7 Impairment of Assets in 2006 includes (i) a $650.5 million goodwill impairment associated with Terasen Gas (see Note 6 of the accompanying Notes to Consolidated Financial Statements) and (ii) a $1.2 million impairment of Power assets. Interest and Other Corporate Expenses, Net for 2006 include (i) a reduction in pre-tax income of $22.3 million ($14.1 million after tax) resulting from non-cash charges to mark to market certain interest rate swaps and (ii) miscellaneous other items totaling a net decrease of $0.8 million in pre-tax income ($0.5 million after tax).

8 The Impairment of Assets in 2005 was a pre-tax charge of $6.5 million ($4.1 million after tax) for the impairment of certain investments in our Power business segment. Interest and Other Corporate Expenses, Net for 2005 include (i) pre-tax gains of $73.9 million ($31.6 million after tax) from the sale of Kinder Morgan Management shares during the second

and fourth quarters of 2005, (ii) a pre-tax charge of $15.0 million ($9.5 million after tax) for our contribution to the Kinder Morgan Foundation, (iii) net pre-tax gains on currency transactions and swaps of $2.3 million ($1.4 million after tax) and (iv) a decrease in after-tax minority interest expense in Kinder Morgan Management of $19.6 million due principally to the items discussed in Note 3 above.

[9] Results for 2004 include (i) a pre-tax charge of $15.0 million ($9.4 million after tax), net of the recognition of deferred power development revenues and the impact of the resolution of certain litigation contingencies, for the impairment of certain investments in our Power business segment (which impairment is presented in the Impairment of Assets line), (ii) a pre-tax charge of $3.9 million ($2.4 million after tax) due to the early extinguishment of debt and (iii) miscellaneous other items totaling a net decrease of $1.6 million in pre-tax income ($1.0 million after tax).

[10] Results for 2006 include a reduction in the income tax provision of $38.0 million resulting from the adjustment of deferred tax liability amounts.

[11] Results for 2004 include a reduction in the income tax provision of $65.5 million resulting from the adjustment of deferred tax liability amounts.

[12] Our income from continuing operations for 2006 includes the effects of certain items of Kinder Morgan Energy Partners on our income totaling a net increase in pre-tax earnings of $3.2 million ($1.4 million after tax).

Our income from continuing operations decreased from $529.9 million in 2005 to $48.7 million in 2006. The principal reason for this decline was the impairment of certain assets as discussed in Note 6 of the accompanying Notes to Consolidated Financial Statements. Before this impairment charge, our income from continuing operations increased from $529 million in 2005 to $699.2 million in 2006, an increase of $169.3 million (32%). The items discussed in footnotes 3, 4, 5, 7, 8 and 12 of the table above, excluding the effect of 2006 asset impairments, had the effect of increasing 2006 earnings, relative to 2005, by $27.2 million. The remaining $142.1 million increase in our 2006 income from continuing operations, before the charge for asset impairment, principally resulted from (i) our acquisition of Terasen on November 30, 2005, (ii) increased earnings from Kinder Morgan Energy Partners, net of associated minority interests, (iii) increased earnings from our NGPL and Power business segments and (iv) reduced general and administrative expenses, exclusive of the general and administrative expenses attributable to Terasen and Kinder Morgan Energy Partners. These positive impacts were partially offset by increased interest costs due, in part, to the effect of higher interest rates on our floating-rate debt. Please refer to the individual business segment discussions included elsewhere herein for additional information regarding business segment results. Refer to the headings "Interest and Corporate Expenses, Net," "Earnings from Kinder Morgan Energy Partners," "Income Taxes – Continuing Operations" and "Discontinued Operations" included elsewhere in management's discussion and analysis for additional information regarding these items.

Our income from continuing operations increased from $498.2 million in 2004 to $529.9 million in 2005, an increase of $31.7 million (6%). The items discussed in footnotes 3, 5, 8, 9 and 11 of the table above, in addition to the asset impairment recorded in 2005, had the effect of decreasing 2005 earnings, relative to 2004, by $55.1 million. The remaining $86.8 million increase in our 2005 income from continuing operations, principally resulted from (i) increased earnings from our investment in Kinder Morgan Energy Partners, exclusive of the items discussed in the table above, (ii) increased earnings from our NGPL business segment, (iii) one month of 2005 earnings attributable to our acquisition of Terasen and (iv) a $4.5 million gain on sale of Kinder Morgan Management shares in the first quarter of 2005. These favorable income impacts were partially offset by (i) the contribution of our TransColorado business segment to Kinder Morgan Energy Partners effective November 1, 2004, (ii) increased interest expense due to higher interest rates, interest expense on Terasen's existing debt and interest expense on incremental debt issued to acquire Terasen, (iii) increased general and administrative expenses due principally to the general and administrative costs of Terasen and (iv) increased income taxes.

Diluted earnings per common share from continuing operations decreased from $4.25 in 2005 to $0.36 in 2006. The principal reason for this decline was the impairment of certain assets as discussed in Note 6 of the accompanying Notes to Consolidated Financial Statements. Before this impairment charge, our diluted earnings per common share increased from $4.25 in 2005 to $5.18 in 2006, an increase of $0.93 (22%). This increase reflected, in addition to the financial and operating impacts discussed preceding, an increase of 10.4 million (8%) in average shares outstanding. The increase in average shares outstanding resulted from the net effects of (i) 12.5 million shares issued to acquire Terasen on November 30, 2005, (ii) decreases in shares outstanding due to our share repurchase program (see Note 10(E) of the accompanying Notes to Consolidated Financial Statements), (iii) increases in shares outstanding due to newly-issued shares for (1) the employee stock purchase plan, (2) the issuance of restricted stock and (3) exercises of stock options by employees (see Note 14 of the accompanying Notes to Consolidated Financial Statements) and (iv) the increased dilutive effect of stock options resulting from the increase in the market price of our shares. Total diluted earnings per common share increased from $4.45 in 2005 to $5.35 in 2006, an increase of $0.90 (20%).

Diluted earnings per common share from continuing operations increased from $3.99 in 2004 to $4.25 in 2005, an increase of $0.26 (7%). This increase reflected, in addition to the financial and operating impacts discussed preceding, a decrease of 0.3 million (0.2%) in average shares outstanding. The decrease in average shares outstanding resulted from the net effects of (i)

12.5 million shares issued to acquire Terasen, which were outstanding for one month during 2005, (ii) decreases in shares outstanding due to our share repurchase program (see Note 10(E) of the accompanying Notes to Consolidated Financial Statements), (iii) increases in shares outstanding due to newly-issued shares for (1) the employee stock purchase plan, (2) the issuance of restricted stock and (3) exercises of stock options by employees (see Note 14 of the accompanying Notes to Consolidated Financial Statements) and (iv) the increased dilutive effect of stock options resulting from the increase in the market price of our shares. Total diluted earnings per common share increased from $4.18 in 2004 to $4.45 in 2005, an increase of $0.27 (6%).

Results of Operations

The following comparative discussion of our results of operations is by segment for factors affecting segment earnings, and on a consolidated basis for other factors.

In August 2006, we entered into a definitive agreement with a subsidiary of General Electric Company to sell our U.S. retail natural gas distribution and related operations for $710 million plus working capital. In prior periods, we referred to these operations as the Kinder Morgan Retail business segment. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* the financial results of these operations have been reclassified to discontinued operations for all periods presented. Refer to the heading "Discontinued Operations" included elsewhere in management's discussion and analysis for additional information regarding discontinued operations.

We manage our various businesses by, among other things, allocating capital and monitoring operating performance. This management process includes dividing the company into business segments so that performance can be effectively monitored and reported for a limited number of discrete businesses.

Business Segment	Business Conducted	Referred to As:
Natural Gas Pipeline Company of America and certain affiliates.............	The ownership and operation of a major interstate natural gas pipeline and storage system	Natural Gas Pipeline Company of America, or NGPL
Terasen Natural Gas Distribution..............	The regulated sale and transportation of natural gas to residential, commercial and industrial customers in British Columbia, Canada	Terasen Gas
Petroleum Pipelines..................................	The ownership and operation of crude and refined petroleum pipelines, principally located in Canada, and a one-third interest in the Express System, a crude pipeline system	Kinder Morgan Canada
Power Generation......................................	The ownership and operation of natural gas-fired electric generation facilities	Power
Petroleum Products Pipelines (Kinder Morgan Energy Partners)...................	The ownership and operation of refined petroleum products pipelines that deliver gasoline, diesel fuel, jet fuel and natural gas liquids to various markets; plus associated product terminals and petroleum pipeline transmix processing facilities	Products Pipelines – KMP
Natural Gas Pipelines (Kinder Morgan Energy Partners)................................	The ownership and operation of major interstate and intrastate natural gas pipeline and storage systems	Natural Gas Pipelines – KMP

CO_2 (Kinder Morgan Energy Partners)	The production, transportation and marketing of carbon dioxide (CO_2) to oil fields that use CO_2 to increase production of oil; plus ownership interests in and/or operation of oil fields in West Texas; plus the ownership and operation of a crude oil pipeline system in West Texas	CO_2 - KMP
Liquids and Bulk Terminals (Kinder Morgan Energy Partners).................................	The ownership and/or operation of liquids and bulk terminal facilities and rail transloading and materials handling facilities that together transload, store and deliver a wide variety of bulk, petroleum, petrochemical and other liquids products	Terminals - KMP

The accounting policies we apply in the generation of business segment earnings are generally the same as those applied to our consolidated operations and described in Note 1 of the accompanying Notes to Consolidated Financial Statements, except that (i) certain items below the "Operating Income" line (such as interest expense) are either not allocated to business segments or are not considered by management in its evaluation of business segment performance, (ii) equity in earnings of equity method investees (other than Kinder Morgan Energy Partners, the accounts, balances and results of operations of which are now consolidated with our own) are included in segment earnings (these equity method earnings are included in "Other Income and (Expenses)" in the accompanying Consolidated Statements of Operations), (iii) certain items included in operating income (such as general and administrative expenses) are not considered by management in its evaluation of business segment performance, (iv) gains and losses from incidental sales of assets are included in segment earnings and (v) our business segments that are also segments of Kinder Morgan Energy Partners include certain other income and expenses and income taxes in their segment earnings. With adjustment for these items, we currently evaluate business segment performance primarily based on segment earnings in relation to the level of capital employed. In addition, because Kinder Morgan Energy Partners' partnership agreement requires it to distribute 100% of its available cash to its partners on a quarterly basis (Kinder Morgan Energy Partners' available cash consists primarily of all of its cash receipts, less cash disbursements and changes in reserves), we consider each period's earnings before all non-cash depreciation, depletion and amortization expenses to be an important measure of business segment performance for our segments that are also segments of Kinder Morgan Energy Partners. We account for intersegment sales at market prices, while we account for asset transfers at either market value or, in some instances, book value.

Following are operating results by individual business segment (before intersegment eliminations), including explanations of significant variances between the periods presented.

Natural Gas Pipeline Company of America

	Year Ended December 31,		
	2006	**2005**	**2004**
	(In millions except systems throughput)		
Operating Revenues	$ 1,118.0	$ 947.3	$ 778.9
Gas Purchases and Other Costs of Sales	$ 362.9	$ 299.2	$ 188.8
Segment Earnings..	$ 499.0	$ 435.2	$ 392.8
Systems Throughput (Trillion Btus)................	1,696.3	1,664.8	1,539.6

NGPL's segment earnings increased from $435.2 million in 2005 to $499.0 million in 2006, an increase of $63.8 million (15%). Segment revenues and earnings for 2006 were positively impacted, relative to 2005, by (i) increased transportation and storage revenues in 2006 due principally to successful re-contracting of transportation and storage services, favorable basis differentials and recent transportation and storage system expansions (as discussed below) and (ii) increased operational gas sales prices. These positive impacts were partially offset by (i) $30.2 million of expense for a stress corrosion cracking rehabilitation project (as discussed below) and pipeline integrity management programs, (ii) an increase of $4.6 million in electric compression costs and (iii) a $4.9 million increase in depreciation and amortization expense. NGPL's operational gas sales are primarily made possible by its collection of fuel in-kind pursuant to its transportation tariffs and recovery of storage cushion gas volumes. Total system throughput volumes increased by 31.5 trillion Btus in 2006, relative to 2005 due, in part, to shippers moving significant volumes of natural gas within Texas on NGPL's Gulf Coast Pipeline. The increase in system throughput in 2006, relative to 2005, did not have a significant direct impact on revenues or segment earnings due to the fact that transportation revenues are derived primarily from "firm" contracts in which shippers pay a "demand" fee to reserve a set amount of system capacity for their use.

NGPL's segment earnings increased from $392.8 million in 2004 to $435.2 million in 2005, an increase of $42.4 million (11%). Segment revenues and earnings for 2005 were positively impacted, relative to 2004, by (i) increased transportation and storage service revenues in 2005 resulting, in part, from increased firm demand revenues, the recent expansion of our storage system and the acquisition of the Black Marlin Pipe line and (ii) increased operational gas sales. These positive impacts were partially offset by (i) an increase of $5.2 million in depreciation expense, (ii) an increase of $4.8 million in operations and maintenance expenses, principally attributable to higher electric compression costs, (iii) a $4.4 million increase in taxes other than income taxes, principally attributable to increased property taxes, (iv) the fact that 2004 results included $4.0 million in contractual customer penalty charges in 2004 that were billed prior to December 1, 2003, the effective date for NGPL's Order 637 provisions, but had been reserved pending the final outcome of its Order 637 filings, (v) a $2.1 million reduction in gains from incidental sales of assets and (vi) the negative impact of significant changes in the values of various natural gas price indices relative to the value of the Henry Hub index used by the NYMEX in the valuation of derivative instruments, caused by hurricane-related supply disruptions in the Gulf of Mexico area. The increase in systems throughput in 2005, relative to 2004, was due principally to higher utilization of the Amarillo and Louisiana lines. The increase in systems throughput in 2005, relative to 2004, did not have a significant direct impact on revenues or segment earnings due to the terms of "firm" contracts, as discussed above.

On October 10, 2006, in FERC Docket No. CP 07-3, NGPL filed seeking approval to expand its Louisiana Line by 200,000 dekatherms per day (Dth/day). This $66 million project is supported by five-year agreements that fully subscribe the additional capacity.

In a letter filed on December 8, 2005, NGPL requested that the Office of the Chief Accountant of the Federal Energy Regulatory Commission ("FERC") confirm that NGPL's proposed accounting treatment to capitalize the costs incurred in a one-time pipeline rehabilitation project that will address stress corrosion cracking on portions of NGPL's pipeline system is appropriate. The rehabilitation project will be conducted over a five-year period. On June 5, 2006, in Docket No. AC 06-18, the FERC ruled on NGPL's request to capitalize pipeline rehabilitation costs. The ruling states that NGPL must expense rather than capitalize the majority of the costs. NGPL can continue to capitalize the costs of pipe replacement and coating but costs to assess the integrity of pipe must be expensed.

During the second quarter of 2006, NGPL commenced operation of the following projects: the $21 million Amarillo cross-haul line expansion, which adds 51,000 Dth/day of capacity and is fully subscribed under long-term contracts; the $38 million Sayre storage field expansion in Oklahoma that added 10 billion cubic feet (Bcf) of capacity, which is contracted for under long-term agreements; and a $4 million, 2 Bcf expansion of no-notice delivered storage service.

In the first quarter of 2006, NGPL received certificate approval from the FERC for the $74 million expansion at its North Lansing field in east Texas that will add 10 Bcf of storage service capacity. Construction is underway and the project is expected to be in service in spring 2007.

In 2006, NGPL extended long-term firm transportation and storage contracts with some of its largest shippers, including Northern Illinois Gas Company (Nicor), The Peoples Gas Light and Coke Company, Centerpoint Energy Minnesota Gas, Interstate Power and Light Company, subsidiaries of Ameren Corporation, and Wisconsin Electric Power Co. Combined, the contracts represent approximately 0.49 million Dth per day of annual firm transportation service.

Substantially all of NGPL's pipeline capacity is committed under firm transportation contracts ranging from one to five years. Under these contracts, over 90% of the revenues are derived from a demand charge and, therefore, are collected regardless of the volume of gas actually transported. The principal impact of the actual level of gas transported is on fuel recoveries, which are received in-kind as volumes move on the system. Approximately 63% of the total transportation volumes committed under NGPL's long-term firm transportation contracts in effect on February 13, 2007 had remaining terms of less than three years. Contracts representing approximately 6.3% of NGPL's total long-haul, contracted firm transport capacity as of January 31, 2007 are scheduled to expire during 2007. NGPL continues to actively pursue the renegotiation, extension and/or replacement of expiring contracts.

Our principal exposure to market variability is related to the variation in natural gas prices and basis differentials, which can affect gross margins in our NGPL segment. "Basis differential" is a term that refers to the difference in natural gas prices between two locations or two points in time. These price differences can be affected by, among other things, natural gas supply and demand, available transportation capacity, storage inventories and deliverability, prices of alternative fuels and weather conditions. In recent periods, additional competitive pressures have been generated in Midwest natural gas markets due to the introduction and planned introduction of pipeline capacity to bring additional supplies of natural gas into the

Chicago market area, although incremental pipeline capacity to take gas out of the area has also been constructed. We have attempted to reduce our exposure to this form of market variability by pursuing long-term, fixed-rate type contract agreements to utilize the capacity on NGPL's system. In addition, as discussed under "Risk Management" in Item 7A of this report and in Note 12 of the accompanying Notes to Consolidated Financial Statements, we utilize a comprehensive risk management program to mitigate our exposure to changes in the market price of natural gas and associated transportation.

The majority of NGPL's system is subject to rate regulation under the jurisdiction of the Federal Energy Regulatory Commission. Currently, there are no material proceedings challenging the rates (which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for) on any of our pipeline systems. Nonetheless, shippers on our pipelines do have rights, under certain circumstances prescribed by applicable regulations, to challenge the rates we charge. There can be no assurance that we will not face future challenges to the rates we receive for services on our pipeline systems.

Terasen Gas

	Year Ended December 31, 2006	Month Ended December 31, 2005
	(In millions)	
Operating Revenues	$ 1,523.9	$ 223.3
Gas Purchases and Other Costs of Sales	$ 978.6	$ 156.2
Segment Earnings[1]	$ 312.9	$ 45.2

[1] Does not include $650.5 pre-tax goodwill impairment in 2006.

The results of operations of Terasen Gas are included in our results beginning with the November 30, 2005 acquisition of Terasen. Terasen's natural gas distribution operations consist primarily of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc., collectively referred to in this report as Terasen Gas. Terasen Gas is regulated by the British Columbia Utilities Commission ("BCUC").

On February 26, 2007, we entered into a definitive agreement to sell Terasen Inc. to Fortis Inc. (TSX: FTS), a Canadian-based company with investments in regulated distribution utilities, for approximately $3.2 billion (C$3.7 billion) including cash and assumed debt. Terasen Inc.'s principal assets include Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. The transaction is subject to certain closing conditions and regulatory approvals and is expected to close in mid 2007. This sale does not include assets of Kinder Morgan Canada.

In June 2006, the BCUC approved an application from Terasen Gas Inc. to build a 50-kilometer natural gas pipeline from Squamish to Whistler. The estimated C$42 million project, which includes the cost of retrofitting utility customers' gas-fired appliances from propane to natural gas use, will replace an aging propane system. Construction on this project is being integrated with and performed by the contractor performing the highway upgrades to Whistler in advance of the 2010 Winter Olympics. We expect full service to be available to Whistler by November 2008.

Terasen Gas Inc.'s allowed return on equity ("ROE") is determined annually based on a formula that applies a risk premium to a forecast of long-term Government of Canada bond yields. For 2005, the application of the ROE formula set Terasen Gas Inc.'s allowed ROE at 9.03%, down from 9.15% in 2004. On March 2, 2006, a decision was issued by the BCUC, with an effective date of January 1, 2006, approving changes to Terasen Gas Inc.'s and TGVI's deemed equity components from 33% to 35% and from 35% to 40%, respectively. The same decision also modified the previously existing generic ROE reset formula resulting in an increase in allowed ROEs from the levels that would have resulted from the old formula. The changes increased the allowed ROE from 8.29% to 8.80% for Terasen Gas Inc. and from 8.79% to 9.50% for TGVI in 2006 and the new formula resulted in allowed ROEs for 2007 of 8.37% and 9.07% for Terasen Gas Inc. and TGVI, respectively.

Kinder Morgan Canada (Formerly Terasen Pipelines)

	Year Ended December 31, 2006	Month Ended December 31, 2005
	(In millions)	
Operating Revenues	$ 213.7	$ 18.9
Segment Earnings	$ 119.9	$ 12.5

The results of operations of Kinder Morgan Canada (formerly Terasen Pipelines) are included in our results beginning with the November 30, 2005 acquisition of Terasen. Kinder Morgan Canada's operations consist primarily of the Trans Mountain pipeline, the Corridor pipeline and a one-third interest in the Express System.

In November 2004, Trans Mountain entered into negotiations with the Canadian Association of Petroleum Producers ("CAPP") and principal shippers for a new Incentive Toll Settlement to be effective for the period starting January 1, 2006 and ending December 31, 2010 (the "2006 ITS"). In January 2006, Trans Mountain reached agreement in principle reduced to a memorandum of understanding for the 2006 ITS. A final agreement was reached with CAPP in October 2006 and NEB approval was received in November 2006. The 2006 ITS provides the commercial support for the much needed first phase of expansion of the Trans Mountain pipeline system, which will increase capacity to 300,000 barrels per day ("bpd"). The project includes the Trans Mountain pump station expansion that will increase pipeline capacity from the current 225,000 bpd to 260,000 bpd by April 2007, and the Anchor Loop expansion, which will add an additional 40,000 bpd of new capacity to the west coast of British Columbia and Washington state by late 2008. These projects represent approximately C$638 million in capital investments and reflect a commitment by Kinder Morgan Canada to progressively expand pipeline capacity from Alberta to serve markets in Canada, the United States and offshore.

Kinder Morgan Canada filed a comprehensive environmental report with the Canadian Environmental Assessment Agency on November 15, 2005, and filed a complete NEB application for the Anchor Loop Project on February 17, 2006. The C$443 million project involves looping a 98-mile section of the existing Trans Mountain pipeline system between Hinton, Alberta, and Jackman, British Columbia, and the addition of three new pump stations. With construction of the Anchor Loop, the Trans Mountain system's capacity will increase from 260,000 bpd to 300,000 bpd by the end of 2008. The public hearing of the application was held the week of August 8, 2006. On October 26, 2006, the NEB released its favorable decision on the application.

On November 10, 2005, Kinder Morgan Canada received approval from the NEB to increase the capacity of the Trans Mountain pipeline system from 225,000 bpd to 260,000 bpd. The C$195 million expansion is designed to add 35,000 bpd of heavy crude oil capacity by building new and upgrading existing pump stations along the pipeline system between Edmonton, Alberta, and Burnaby, British Columbia. Construction began in the summer of 2006 and the expansion is expected to be in service by April 2007.

On May 2, 2006, Kinder Morgan Canada announced the start of a binding open season for the second major stage of its West Coast expansion of the Trans Mountain pipeline system. Known as TMX-2, this proposed project would add 100,000 bpd of incremental capacity to the Trans Mountain pipeline system, bringing the pipeline's total capacity to approximately 400,000 bpd. The TMX-2 open season began on May 2, 2006, and closed on July 17, 2006 without full subscription for the expanded pipeline. Discussions with shippers are ongoing and we remain confident that shippers will ultimately support the expansion. TMX-2 is part of a multi-staged expansion designed to link growing western Canadian oil production with West Coast and offshore markets. The project consists of two pipeline loops: (i) 252 kilometers of 36-inch diameter pipe in Alberta between Edmonton and Edson, and (ii) 243 kilometers of 30- and 36-inch diameter pipe in British Columbia between Rearguard and Darfield, north of Kamloops. The proposed loops will generally follow the existing 24-inch diameter Trans Mountain pipeline. New pump stations and storage tank facilities will also be required for the TMX-2 project.

We have initiated engineering, environmental, consultation and procurement activities on the proposed Corridor pipeline expansion project, as authorized and supported by shipper resolutions and the underlying firm service agreement. The proposed C$1.8 billion expansion includes building a new 42-inch diameter diluent/bitumen ("dilbit") pipeline, a new 20-inch diameter products pipeline, tankage and upgrading existing pump stations along the existing pipeline system from the Muskeg River Mine north of Fort McMurray to the Edmonton region. The Corridor pipeline expansion would add an initial 180,000 bpd of dilbit capacity to accommodate the new bitumen production from the Muskeg River Mine. An expansion of the Corridor pipeline system has been completed in 2006 increasing the dilbit capacity to 278,000 bpd by upgrading existing pump station facilities. By 2009, the dilbit capacity of the Corridor system is expected to be approximately 460,000 bpd. An application for the Corridor pipeline expansion project was filed with the Alberta Energy Utilities Board and Alberta Environment on December 22, 2005, and approval was received in August 2006. Construction of the Corridor pipeline expansion began in November 2006 as the shippers have received definitive approval of their Muskeg River Mine expansion.

Power

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Operating Revenues	$ 60.0	$ 54.2	$ 70.0
Gas Purchases and Other Costs of Sales	$ 8.4	$ 3.5	$ 4.7
Segment Earnings[1]	$ 21.1	$ 19.7	$ 15.3

[1] Does not include (i) pre-tax charges of $6.5 million and $33.5 million in 2005 and 2004, respectively, to record the impairment of certain assets, (ii) incremental earnings of $18.5 million in 2004 reflecting (1) the recognition of previously deferred revenues associated with construction of the Jackson, Michigan power generation facility, (2) gains from the sale of surplus power generation equipment and (3) the settlement of certain litigation. These items are discussed below.

Power's segment earnings, as reported above, increased from $19.7 million in 2005 to $21.1 million in 2006, an increase of $1.4 million (7%). Segment results were positively impacted in 2006, relative to 2005, by (i) the recognition of $2.7 million of gains from surplus equipment sales (see Note 5 of the accompanying Notes to Consolidated Financial Statements) and (ii) a reduction in amortization expense resulting from prior period asset write-downs. These positive impacts were offset by (i) a pre-tax charge of $1.2 million to reduce the carrying value of certain surplus equipment held for sale and (ii) a $0.3 million reduction in earnings from Thermo Cogeneration Partnership due, in part, to (i) the fact that 2005 results included proceeds from the resolution of the Enron bankruptcy proceeding and (ii) increased operating expenses.

Power's segment earnings, as reported above, increased from $15.3 million in 2004 to $19.7 million in 2005, an increase of $4.4 million (29%). Segment earnings for 2005 were positively impacted, relative to 2004, principally by a $3.0 million increase in equity earnings from Thermo Cogeneration Partnership due largely to (i) the favorable resolution of claims in the Enron bankruptcy proceeding, (ii) higher capacity revenues and (iii) reduced 2005 interest expense resulting from the repayment of long-term debt. In addition, Power was positively impacted by earnings from providing operating and maintenance management services, starting in June 2005, at a new 103-megawatt combined-cycle natural gas-fired power plant in Snyder, Texas, which is generating electricity for Kinder Morgan Energy Partners' SACROC operations. Certain surplus power generation equipment was sold during 2004 (see Note 5 of the accompanying Notes to Consolidated Financial Statements). We recorded $3.9 million of pre-tax gains from these sales in 2004, which are excluded from segment earnings as reported above. In addition, we recorded revenues of $13.3 million and $1.3 million in 2004 resulting from development fees associated with the Jackson, Michigan power plant and the favorable settlement of litigation matters, respectively, which are excluded from the tabular presentation of segment earnings as reported above.

In February 2001, Kinder Morgan Power announced an agreement under which Williams Energy Marketing and Trading agreed to supply natural gas to and market capacity for 16 years for a 550-megawatt natural gas-fired Orion technology electric power plant in Jackson, Michigan. Effective July 1, 2002, construction of this facility was completed and commercial operations commenced. Concurrently with commencement of commercial operations, (i) Kinder Morgan Power made a preferred investment in Triton Power Company LLC (now valued at approximately $119 million); and (ii) Triton Power Company LLC, through its wholly owned subsidiary, Triton Power Michigan LLC, entered into a 40-year lease of the Jackson power facility from the plant owner, AlphaGen Power, LLC. Williams Energy Marketing and Trading supplies all natural gas to and purchases all power from the power plant under a 16-year tolling agreement with Triton Power Michigan LLC. Our preferred equity interest has no management or voting rights, but does retain certain protective rights, and is entitled to a cumulative return, compounded monthly, of 9.0% per annum. No income was recorded in 2006 and no income is expected in 2007 from this preferred investment due to the fact that the dividend on this preferred is not currently being paid, and uncertainty concerning the date at which such distributions will be received.

In May 2000, Kinder Morgan Power and Mirant Corporation (formerly Southern Energy Inc.) announced plans to build a 550 megawatt natural gas-fired electric power plant in Wrightsville, Arkansas, utilizing Kinder Morgan Power's Orion technology. Construction of this facility was completed on July 1, 2002 and commercial operations commenced. During the third quarter of 2003, we announced that Mirant had placed the Wrightsville, Arkansas plant in bankruptcy, and we would assess the long-term prospects for this facility during the fourth quarter. In December 2003, we completed our analysis and determined that it was no longer appropriate to assign any carrying value to our investment in this facility and recorded a $44.5 million pre-tax charge, effectively writing off our remaining investment in the Wrightsville power facility. During the third quarter of 2005, and subsequent to a negotiated settlement agreement approved by the court, Mirant sold the Wrightsville power facility to Arkansas Electric Cooperative Corporation.

During 2002, we noted that a number of factors had negatively affected Power's business environment and certain of its current operations. These factors, which are currently expected to continue in the near to intermediate term, include (i) volatile and generally declining prices for wholesale electric power in certain markets, (ii) cancellation and/or postponement of the construction of a number of new power generation facilities, (iii) difficulty in obtaining air permits with acceptable operating conditions and constraints and (iv) a marked deterioration in the financial condition of a number of participants in the power generating and marketing business, including participants in the power plants in Jackson, Michigan and Wrightsville, Arkansas. During the fourth quarter of 2002, after completing an analysis of these and other factors to determine their impact on the market value of these assets and the prospects for this business in the future, we (i) determined that we would no longer pursue power development activities and (ii) recorded a $134.5 million pre-tax charge to reduce the carrying value of our investments in (1) sites for future power plant development, (2) power plants and (3) turbines and associated equipment.

Since 1998, we have had an investment in a 76 megawatt gas-fired power generation facility located in Greeley, Colorado. We became concerned with the value of this investment as a result of several recent circumstances including the expiration of a gas purchase contract, the amendment of the associated power purchase agreement and uncertainties surrounding the management of this facility, which has changed ownership twice in the last one and one-half years. These ownership changes made it difficult for us to obtain information necessary to forecast the future of this asset. During the fourth quarter of 2004, we concluded that we had sufficient information to determine that our investment had been impaired and, accordingly, reduced our carrying value by $26.1 million. During the fourth quarter of 2005, we concluded that we had sufficient information to determine that our investment had been further impaired and, accordingly, reduced our carrying value by an additional $6.5 million. These charges are excluded from the tabular presentation of segment earnings as reported above.

During 2004, we sold five of our surplus turbines and certain associated equipment, including certain equipment to Kinder Morgan Energy Partners (see Note 5 of the accompanying Notes to Consolidated Financial Statements). Recognizing the effects of changes in technology and the limited improvement of the general economies of the electric generation industry, we determined that the carrying values of our remaining turbines and associated equipment should be reduced. In the fourth quarter of 2004, we reduced the carrying value of these assets by $7.4 million. This charge is excluded from segment earnings as reported above. In addition, in the fourth quarter of 2006, we reduced the carrying value of our remaining surplus equipment held for sale by $1.2 million. We are continuing our efforts to sell the remaining inventory of surplus equipment, which had a carrying value of $4.3 million at December 31, 2006.

Pursuant to a right we obtained in conjunction with the 1998 acquisition of the Thermo Companies, in December 2003, we made an additional investment in our Colorado power businesses in the form of approximately 1.8 million Kinder Morgan Management shares that we owned. We delivered these shares to an entity controlled by the former Thermo owners, which entity is required to retain the shares until they vest (400,000 shares vested each January 1 of 2004, 2005 and 2006, and the remainder vested on January 1, 2007). We recorded our increased investment based on the third-party-determined $56.1 million fair value of the shares as of the contribution date, with a corresponding liability representing our obligation to deliver vested shares in the future. The effect of this incremental investment will be to increase our ownership interest in the Thermo entities beginning in 2010.

We have entered into a purchase and sale agreement with a third party to sell our interests in the Power segment's three natural gas-fired electricity generation facilities located in Colorado. The sale is subject to a right of first refusal and regulatory approvals. There can be no assurance that the conditions to the completion of this transaction will be satisfied.

Products Pipelines – KMP

	Year Ended December 31,		
	2006	2005	2004
	(In millions, except operating statistics)		
Revenues	$ 776.3	$ 711.9	$ 645.2
Operating Expenses(Including Adjustments)[a]	(308.3)	(366.0)	(222.0)
Earnings from Equity Investments[b]	16.3	28.4	29.0
Interest Income and Other, Net– Income (Expense)[c]	12.0	6.1	4.7
Income Taxes[d]	(5.1)	(10.3)	(12.0)
Earnings Before Depreciation, Depletion and Amortization Expense and Amortization of Excess Cost of Equity Investments	491.2	370.1	444.9
Depreciation, Depletion and Amortization Expense	(82.9)	(79.2)	(71.3)
Amortization of Excess Cost of Equity Investments	(3.4)	(3.4)	(3.3)
Segment Earnings	$ 404.9	$ 287.5	$ 370.3

	Year Ended December 31,		
	2006	**2005**	**2004**
Gasoline (MMBbl)	455.2	457.8	459.1
Diesel Fuel (MMBbl)	161.0	166.0	161.7
Jet Fuel (MMBbl)	119.5	118.1	117.8
Total Refined Products Volumes (MMBbl)	735.7	741.9	738.6
Natural Gas Liquids (MMBbl)	38.8	37.3	43.9
Total Delivery Volumes (MMBbl)[e]	774.5	779.2	782.5

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[a] 2006 amount includes expense of $13.5 million associated with supplemental environmental liability adjustments. 2005 amount includes expense of $19.6 million associated with environmental liability adjustments, expense of $105.0 million associated with a rate case liability adjustment, and expense of $13.7 million associated with a North System liquids inventory reconciliation adjustment. 2004 amount includes expense of $30.6 million associated with environmental liability adjustments.

[b] 2006 amount includes expense of $4.9 million associated with environmental liability adjustments on Plantation Pipe Line Company.

[c] 2006 amount includes income of $5.7 million from the settlement of transmix processing contracts.

[d] 2006 amount includes a decrease in expense of $1.9 million associated with the tax effect on our share of environmental expenses incurred by Plantation Pipe Line Company and described in footnote (b).

[e] Includes Pacific, Plantation, North System, CALNEV, Central Florida, Cypress and Heartland pipeline volumes.

Due to the adoption of EITF 04-5 (see Note 1(B) of the accompanying Notes to Consolidated Financial Statements), effective January 1, 2006, we include the results of operations of Kinder Morgan Energy Partners in our consolidated results of operations. Although we accounted for Kinder Morgan Energy Partners under the equity method during 2005 and 2004, for comparative purposes, the following discussion regarding the segment results of the Products Pipelines – KMP business segment includes segment results for 2006, 2005 and 2004.

The Products Pipelines - KMP segment's primary businesses include transporting refined petroleum products and natural gas liquids through pipelines and operating liquid petroleum products terminals and petroleum pipeline transmix processing facilities. The segment reported earnings before depreciation, depletion and amortization of $491.2 million on revenues of $776.3 million in 2006. This compares with earnings before depreciation, depletion and amortization of $370.1 million on revenues of $711.9 million in 2005, and earnings before depreciation, depletion and amortization of $444.9 million on revenues of $645.2 million in 2004.

Segment Earnings before Depreciation, Depletion and Amortization

The segment's overall $121.1 million (33%) increase in earnings before depreciation, depletion and amortization expenses in 2006 compared with 2005 and its $74.8 million (17%) decrease in earnings before depreciation, depletion and amortization expenses in 2005 compared with 2004 included an increase of $127.5 million and a decrease of $107.6 million, respectively, from the combined net effect of the certain other items described in the footnotes to the table above. These items consisted of the following:

- an increase in earnings of $5.7 million in 2006—related to two separate contract settlements from the petroleum transmix processing operations. First, we recorded income of $6.2 million from fees received for the early termination of a long-term transmix processing agreement at the Colton, California processing facility. Secondly, we recorded an expense of $0.5 million related to payments made to Motiva Enterprises LLC in June 2006 to settle claims for prior period transmix purchase costs at the Richmond, Virginia processing facility. We included the net income of $5.7 million from these two items within "Other, Net" in the accompanying Consolidated Statement of Operations for the year ended December 31, 2006;

- a decrease in earnings of $105.0 million in 2005—due to an increase in operating expenses related to an adjustment to the products pipelines rate case liability in December 2005. This adjustment is more fully described above in "Critical Accounting Policies and Estimates—Regulatory and Legal Matters;"

- decreases in earnings of $16.4 million, $19.6 million and $30.6 million, respectively in 2006, 2005 and 2004—due to the increases in expenses associated with the adjustments of our environmental liabilities; and

- a decrease in earnings of $13.6 million in 2005—due to an increase in operating expenses related to adjustments made to account for differences between physical and book natural gas liquids inventory on our North System natural gas liquids pipeline. This inventory expense was based on a reconciliation of the North System's natural gas liquids inventory that was completed in the fourth quarter of 2005.

The remaining $6.4 million (1%) decrease in earnings before depreciation, depletion and amortization expenses in 2006 compared with 2005, and the remaining $32.8 million (7%) increase in earnings before depreciation, depletion and amortization expenses in 2005 compared with 2004 consisted of the following items:

- a decrease in earnings of $24.2 million in 2006—due to incremental pipeline maintenance expenses recognized in the last half of 2006. Beginning in the third quarter of 2006, the refined petroleum products pipelines and associated terminal operations included within the Products Pipelines – KMP segment (including Plantation Pipe Line Company, Kinder Morgan Energy Partners' 51%-owned equity investee) began recognizing certain costs incurred as part of its pipeline integrity management program as maintenance expense in the period incurred, and in addition, recorded an expense for costs previously capitalized during the first six months of 2006. The overall decrease in earnings consisted of an $11.6 million decrease related to a change that transferred certain pipeline integrity management costs from sustaining capital expenditures (within "Property, Plant and Equipment, Net" on our accompanying Consolidated Balance Sheets) to maintenance expense (within "Operations and Maintenance" in our accompanying Consolidated Statements of Operations) and a $12.6 million decrease related to the expensing of pipeline integrity costs in the second half of 2006.

  Pipeline integrity costs encompass those costs incurred as part of an overall pipeline integrity management program, which is a process for assessing and mitigating pipeline risks in order to reduce both the likelihood and consequences of incidents. An effective pipeline integrity program is a systematic, comprehensive process that entails pipeline assessment services, maintenance and repair services, and regulatory compliance. Our pipeline integrity program is designed to provide our management the information needed to effectively allocate resources for appropriate prevention, detection and mitigation activities. Combined, this change reduced the segment's earnings before depreciation, depletion and amortization expenses by $24.2 million in 2006—increasing maintenance expenses by $20.1 million, decreasing earnings from equity investments by $6.6 million, and decreasing income tax expenses by $2.5 million;

- increases of $4.9 million (15%) and $18.6 million (133%), respectively, from the Southeast refined products terminal operations. The Southeast terminal operations consist of 24 refined products terminals located in the southeastern United States that Kinder Morgan Energy Partners acquired since December 2003. The increase in earnings before depreciation, depletion and amortization in 2006 compared to 2005 was driven by higher liquids throughput volumes at higher rates, relative to 2005, and higher margins from ethanol blending and sales activities.

  The 2005 increase included incremental earnings of $12.2 million from both the seven refined products terminal operations Kinder Morgan Energy Partners acquired in March 2004 from Exxon Mobil Corporation and the nine refined products terminal operations Kinder Morgan Energy Partners acquired in November 2004 from Charter Terminal Company and Charter-Triad Terminals, LLC. This incremental amount represents the acquired terminals' earnings during the additional months of ownership in 2005, as compared to 2004, and does not include increases or decreases during the same months Kinder Morgan Energy Partners owned the assets in both years. The remaining $6.4 million (46%) increase in earnings in 2005 versus 2004 (representing the increase from the same months Kinder Morgan Energy Partners owned all assets in both years) was primarily due to higher product throughput revenues;

- increases of $4.1 million (1%) and $20.8 million (7%), respectively, from the combined Pacific and CALNEV Pipeline operations. The increase in earnings in 2006 compared to 2005 was primarily due to a $22.6 million (6%) increase in operating revenues, which more than offset an $18.3 million (18%) increase in combined operating expenses. The increase in operating revenues consisted of a $14.7 million (5%) increase from refined products deliveries and a $7.9 million (8%) increase from terminal and other fee revenue. The increase in operating expenses included incremental environmental expenses of $7.3 million and incremental fuel and power expenses of $8.3 million. These incremental environmental expenses were associated with the quarterly true-ups of estimated environmental liability adjustments and were not included with the expenses associated with the supplemental environmental liability adjustments discussed above in "Critical Accounting Policies and Estimates—Environmental Matters." The increase in fuel and power expenses in 2006 compared to 2005 was largely the result of higher electricity usage and higher utility rates in 2006.

  The increase in earnings in 2005 compared to 2004 was primarily revenue driven—revenues from refined petroleum products deliveries increased $24.1 million (9%) and terminal service revenues increased $7.5 million (8%). The increase reflects higher pipeline delivery revenues from the Pacific operations' North Line pipeline, largely due to the completion of a $95 million capital expansion project in December 2004. The expansion project increased the capacity of the North Line by approximately 40%, and involved the replacement of an existing 70-mile, 14-inch diameter pipeline segment with a new 20-inch diameter line and the rerouting of certain pipeline segments away from environmentally sensitive areas and residential neighborhoods;

- increases of $3.7 million (12%) and $1.2 million (4%), respectively, from the Central Florida Pipeline. Both increases were mainly due to higher year-over-year product delivery revenues—the 2006 revenue increase was driven by higher average tariff and terminal rates, and the 2005 revenue increase resulted from an 8% increase in throughput delivery volumes;

- an increase of $3.1 million (11%) and a decrease of $1.7 million (6%) respectively, from the combined operations of the North System and Cypress natural gas liquids pipelines. The increase in earnings in 2006 compared to 2005 consisted of a $3.3 million (15%) increase from the North System and a $0.2 million (4%) decrease from the Cypress Pipeline. The increase from the North System was primarily due to a $2.5 million (6%) increase in system throughput revenues, and the decrease from Cypress was mainly due to higher fuel and power costs, related to an over 2% increase in natural gas liquids delivery volumes in 2006 versus 2005.

  The decrease in earnings in 2005 compared to 2004 consisted of a $0.8 million (4%) decrease from the North System and a $0.9 million (15%) decrease from the Cypress Pipeline. The North System decrease was mainly due to higher product storage expenses, related to both a new storage contract agreement entered into in April 2004 and higher levels of year-end inventory in 2005. The Cypress Pipeline decrease was driven by lower revenues, the result of a 17% decrease in throughput volumes that was largely due to the third quarter 2005 hurricane-related closure of a petrochemical plant in Lake Charles, Louisiana that is served by the pipeline.

- an increase of $2.6 million (13%) and a decrease of $2.0 million (9%), respectively, from the petroleum pipeline transmix processing operations. The 2006 increase consisted of incremental earnings of $3.0 million from the inclusion of the Greensboro, North Carolina transmix facility in 2006, and a decrease in earnings of $0.4 million from the combined operations of the remaining transmix facilities, largely due to higher operating, fuel and power costs which offset increases in processing revenues. In the second quarter of 2006, Kinder Morgan Energy Partners completed construction and placed into service the approximate $11 million Greensboro facility, which is capable of processing 6,000 barrels of transmix per day for Plantation and other interested parties. In 2006, the facility earned revenues of $3.6 million and incurred operating expenses of $0.6 million.

  The $2.0 million decrease in earnings in 2005 relative to 2004 was due to both lower revenues and lower other income. The decrease in revenues was due to a nearly 6% decrease in processing volumes, largely resulting from the disallowance, beginning in July 2004, of methyl tertiary-butyl ether blended transmix in the State of Illinois. The decrease in other income was due to a $0.9 million benefit taken from the reversal of certain short-term liabilities in the second quarter of 2004;

- an increase of $1.6 million (8%) and a decrease of $3.4 million (15%), respectively, from Kinder Morgan Energy Partners' 49.8% ownership interest in the Cochin pipeline system. The 2006 increase was largely related to lower pipeline operating expenses in 2006 compared to 2005. The decrease in expenses, including labor and power costs, resulted from year-to-year decreases in both pipeline delivery volumes and pipeline repair costs. The decrease in expenses more than offset a 1% drop in operating revenues in 2006 versus 2005, due mainly to a decrease in transportation volumes resulting from pipeline operating pressure restrictions.

  The decrease in earnings in 2005 resulted from both lower transportation revenues and higher operating expenses, when compared to 2004. The decrease in revenues was due to a drop in delivery volumes caused by extended pipeline testing and repair activities and by warmer winter weather, and the increase in operating expenses was due principally to higher pipeline repair, maintenance and testing costs;

- decreases of $2.0 million (5%) and $2.6 million (6%), respectively, from the West Coast terminal operations. The 2006 decrease reflects incremental environmental expenses of $6.2 million recognized in 2006 and not included with the expenses associated with the supplemental environmental liability adjustments discussed above. These environmental expenses followed quarterly reviews of any potential environmental issues that could impact the West Coast terminal operations and, when aggregated with all remaining expenses, resulted in a combined $9.0 million (46%) increase in operating expenses in 2006 versus 2005. The higher expenses more than offset a $6.5 million (11%) increase in operating revenues, largely attributable to higher fees from ethanol blending services and from revenue increases across all service activities performed at the Carson, California and connected Los Angeles Harbor products terminal.

The decrease in earnings in 2005 compared to 2004 was largely due to higher property tax expenses in 2005, due to expense reversals taken in the second quarter of 2004 pursuant to favorable property reassessments, and to lower product revenues resulting from the fourth quarter 2004 closure of the Gaffey Street products terminal located in San Pedro, California; and

- a decrease of $0.2 million (0%) and an increase of $1.9 million (6%), respectively, from Kinder Morgan Energy Partners' approximate 51% ownership interest in Plantation Pipe Line Company. Earnings before depreciation, depletion and amortization from the investment in Plantation were essentially flat in 2006 versus 2005, as lower equity earnings were mostly offset by lower operatorship expenses. The decrease in both lower net income and pipeline operating expenses were associated with lower year-to-year transportation revenues, due primarily to an almost 7% drop in overall refined products delivery volumes in 2006. The decline in volumes was primarily due to alternative pipeline service into Southeast markets and to changes in supply from Louisiana and Mississippi refineries related to new ultra low sulfur diesel and ethanol blended gasoline requirements. The drop in revenues was largely offset by lower operating and power expenses, due to the lower transportation volumes.

  The increase in earnings in 2005 relative to 2004 was mainly due to the recognition, in 2005, of incremental interest income of $2.5 million on Kinder Morgan Energy Partners' long-term note receivable from Plantation. In July 2004, Kinder Morgan Energy Partners loaned $97.2 million to Plantation to allow it to pay all of its outstanding credit facility and commercial paper borrowings and in exchange for this funding, Kinder Morgan Energy Partners received a seven year note receivable bearing interest at the rate of 4.72% per annum.

Segment Details

Revenues for the segment increased $64.4 million (9%) in 2006 compared to 2005, and increased $66.7 million (10%) in 2005 compared to 2004. The respective year-to-year increases in segment revenues were principally due to the following:

- increases of $24.5 million (43%) and $33.1 million (141%), respectively, from the Southeast terminals. The 2006 increase was largely attributable to higher ethanol blending and sales revenues and higher liquids inventory sales (offset by higher costs of sales, as described below). The 2005 increase was primarily due to terminal acquisitions—including incremental revenues of $23.5 million attributable to the Charter terminals Kinder Morgan Energy Partners acquired in November 2004, and $2.6 million attributable to the ExxonMobil terminals Kinder Morgan Energy Partners acquired in March 2004;

- increases of $16.2 million (5%) and $26.6 million (8%), respectively, from the Pacific operations. The increase in revenues in 2006 compared to 2005 consisted of a $9.8 million (4%) increase in refined products delivery revenues and a $6.4 million (7%) increase in refined products terminal revenues in 2006, compared to 2005. The increase from product deliveries reflect a 2% increase in mainline delivery volumes in 2006, and includes the impact of both rate reductions that went into effect on May 1, 2006, based on FERC filings associated with the Pacific operations' rate litigation, and rate increases that went into effect July 1, 2006 and July 1, 2005, according to the FERC annual index rate increase (a producer price index-finished goods adjustment). The increase from terminal revenues was due to the higher transportation barrels and to incremental service revenues, including diesel lubricity-improving injection services that Kinder Morgan Energy Partners began offering in May 2005.

- The Pacific operations' $26.6 million increase in revenues in 2005 relative to 2004 included increases of $21.2 million (9%) from mainline refined products delivery revenues and $5.4 million (6%) from incremental terminal revenues. The increase from products delivery revenues was driven by a 2% increase in mainline delivery volumes and by increases in average mainline tariff rates; the increase from terminal operations was primarily due to increased terminal and ethanol blending services, largely as a result of the increase in pipeline throughput, and to incremental revenues from diesel lubricity-improving injection services.

- The increase in mainline tariff rates included both FERC approved annual indexed interstate tariff increases in July 2004 and 2005, and a filed rate increase on the completed North Line expansion with the California Public Utility Commission. In November 2004, Kinder Morgan Energy Partners filed an application with the CPUC requesting a $9 million increase in existing California intrastate transportation rates to reflect the in-service date of the $95 million North Line expansion project. Pursuant to CPUC regulations, this increase automatically became effective December 22, 2004, but is being collected subject to refund, pending resolution of protests to the application by certain shippers;

- an increase of $6.5 million (11%) in 2006 versus 2005 from the West Coast terminals. Terminal revenues were flat across both 2005 and 2004, but increased in 2006 compared to 2005 due to storage rent escalations, higher throughput barrels and rates at various locations, and additional tank capacity at the Carson/Los Angeles Harbor system terminals;

- increases of $6.4 million (11%) and $5.0 million (9%), respectively, from the CALNEV Pipeline. The increase in 2006 compared to 2005 consisted of a $4.9 million (11%) increase from higher refined products deliveries and a $1.5 million (11%) increase from overall terminal revenues. The increase from products deliveries was due to a 4% increase in delivery volumes and a 6% increase in average tariff rates (including FERC annual index rate increases in July 2006 and 2005). The higher terminal revenues resulted primarily from additional transportation barrel deliveries at the Barstow, California and Las Vegas, Nevada terminals, and from higher diesel lubricity additive injection service revenues. The $5.0 million increase in revenues in 2005 versus 2004 consisted of a $2.9 million (7%) increase from refined products delivery revenues, primarily due to volume growth, and a $2.1 million (19%) increase from terminal operations, due to higher product storage, injection and ethanol blending services;

- increases of $3.8 million (10%) and $2.8 million (8%), respectively, from the Central Florida Pipeline. The 2006 increase was due to a 10% increase in average tariff rates compared to 2005. The increased rates reflect reductions in zone-based credits in 2006 versus 2005. The year-to-year increase in revenues in 2005 compared to 2004 was due to an 8% increase in transport volumes, partly due to hurricane-related pipeline delivery disruptions in the State of Florida during the third quarter of 2004;

- increases of $2.5 million (6%) and $1.4 million (3%), respectively, from the North System. The 2006 increase was due to higher natural gas liquids delivery revenues in 2006 versus 2005, driven by a 5% increase in system throughput volumes. The volume increase was primarily related to additional refinery demand in 2006 versus 2005.

- The 2005 increase was due to higher average tariff rates, which more than offset a drop in revenues caused by a decline in delivery volumes. The increase in tariff rates in 2005 over 2004 resulted from both a higher ratio of long haul shipments to shorter haul shipments and, to a lesser extent, higher published tariff rates that were approved by the FERC and became effective April 1, 2005. The new rates were associated with a cost of service filing that was approved by the FERC. The decline in volumes was mainly related to lower propane demand due to warmer winter weather in the Midwest during 2005 relative to 2004; and

- decreases of $0.5 million (1%) and $1.8 million (5%), respectively, from Kinder Morgan Energy Partners' ownership interest in the Cochin pipeline system, as described above.

Combining all of the segment's operations, total delivery volumes of refined petroleum products decreased 0.8% in 2006 compared to 2005, but increased 0.4% in 2005 compared to 2004. Compared to last year, the Pacific operations' total delivery volumes were up 1.7%, due in part to the East Line expansion, which was in service for the last seven months of 2006. The expansion project substantially increased pipeline capacity from El Paso, Texas to Tucson and Phoenix, Arizona. In addition, the CALNEV Pipeline delivery volumes were up 4.2% in 2006 versus 2005, due primarily to strong demand from the Southern California and Las Vegas, Nevada markets. The overall decrease in year-to-year segment deliveries of refined products was largely related to a 6.8% drop in volumes from the Plantation Pipeline in 2006, as described above. Compared to 2005, total deliveries of natural gas liquids increased 4.0% in 2006, driven by the higher volumes on the North System.

For 2005, the overall increase in delivery volumes compared with 2004 included increases on Pacific, Central Florida and CALNEV, offset by a decrease on Plantation. Excluding Plantation, which was impacted by Gulf Coast hurricanes and post-hurricane refinery disruptions in 2005, refined products delivery volumes increased 2.5% in 2005 compared to 2004. By product, deliveries of gasoline, diesel fuel and jet fuel increased 1.6%, 5.0% and 2.6%, respectively, in 2005 compared to 2004. Year-to-year deliveries of natural gas liquids were down 15% in 2005 versus 2004. The decrease was due to low demand for propane on both the North System and the Cypress Pipeline. The drop in demand on the North System was primarily due to a minimal grain drying season and to warmer weather in 2005; the drop on Cypress was chiefly due to reduced demand from a petrochemical plant located in Lake Charles, Louisiana, resulting from hurricane-related closures in 2005.

The segment's operating expenses, which consist of all cost of sales expenses, operating and maintenance expenses, fuel and power expenses, and all tax expenses, excluding income taxes, decreased $57.8 million (16%) in 2006 versus 2005 and increased $144.0 million (65%) in 2005 versus 2004. Combined, the net effect attributable to four items previously discussed: (i) the expensing of pipeline integrity costs in 2006; (ii) the adjusting of segment environmental liability balances in 2006, 2005 and 2004; (iii) the adjusting of the Pacific operations' pipeline rate case liability in 2005; and (iv) the expensing of inventory costs associated with the reconciliation of the North System's inventory balances in 2005, resulted in a $104.7 million decrease in operating expenses in 2006 relative to 2005, and a $107.6 million increase in operating expenses in 2005 relative to 2004.

The remaining year-over-year increases of $46.9 million (21%) in 2006 compared to 2005 and $36.4 million (19%) in 2005 compared to 2004, primarily consisted of the following:

- increases of $19.6 million (82%) and $14.5 million (153%), respectively, from the Southeast terminals. The 2006 increase was largely attributable to higher costs of sales related to higher ethanol blending and higher ethanol and liquids purchases (offset by higher ethanol revenues). The 2005 increase was primarily due to incremental expenses related to the terminal operations Kinder Morgan Energy Partners acquired in 2004—including expenses of $13.0 million attributable to the Charter terminals Kinder Morgan Energy Partners acquired in November 2004, and $0.9 million attributable to the ExxonMobil terminals Morgan Energy Partners acquired in March 2004;

- increases of $18.3 million (18%) and $11.7 million (13%), respectively, from the combined Pacific and CALNEV Pipeline operations. The 2006 increase was due to a lower capitalization of expenses, relative to 2005, higher fuel and power, and higher remedial and repair expenses. The decrease in capitalized costs was primarily due to the expensing of pipeline integrity management costs in 2006, versus capitalizing such costs in the prior year. The increase in fuel and power expenses was due to higher refined products delivery volumes and higher average utility rates in 2006, and to a utility rebate credit received in the first quarter of 2005. The increase in pipeline repair expenses was largely related to pipeline failures and releases that have occurred since the end of 2005.

- The $11.7 million increase in expenses in 2005 compared to 2004 was mainly due to higher labor and operating expenses, including incremental power expenses, associated with increased transportation volumes and terminal operations. The segment also incurred higher maintenance and inspection expenses during 2005 as a result of environmental issues, clean-up, and pipeline repairs associated with wash-outs that were caused by flooding in the State of California in the first quarter of 2005;

- increases of $9.0 million (46%) and $1.6 million (9%), respectively, from the West Coast terminals. The increase in expenses in 2006 relative to 2005 was primarily related to incremental environmental expenses of $6.2 million (not related to the segment's supplemental environmental liability adjustments in 2006) and to higher materials and supplies expense as a result of lower capitalized overhead. The increase in operating expenses in 2005 compared to 2004 was chiefly due to higher property tax expenses, described above, and higher cost of sales related to incremental terminal services;

- increases of $0.2 million (2%) and $1.4 million (18%), respectively, from the Central Florida Pipeline operations. The increase in 2006 compared to 2005 was due to incremental environmental expenses (not related to the segment's supplemental environmental liability adjustments in 2006). The increase in operating expenses in 2005 compared to 2004 was primarily due to higher maintenance expenses, due to additional expense accruals related to a pipeline release occurring in September 2005;

- a decrease of $1.7 million (10%) and an increase of $2.9 million (22%), respectively, from Kinder Morgan Energy Partners' proportionate interest in the Cochin Pipeline. The decrease in expenses in 2006 was mainly due to the drop in throughput volumes in 2006 compared to 2005. The increase in expenses in 2005 versus 2004 was primarily due to higher labor and outside services associated with pipeline maintenance and testing costs, and partly due to a full year's inclusion of an additional 5% ownership interest in Cochin. Effective October 1, 2004, Kinder Morgan Energy Partners acquired an additional undivided 5% interest in the Cochin pipeline system for approximately $10.9 million, bringing its total interest to 49.8%; and

- a decrease of $0.5 million (3%) and an increase of $2.9 million (16%), respectively, from the North System. The 2006 decrease was due to both higher product gains and lower fuel and power expenses relative to 2005, partly offset by higher property tax expenses related to an expense true-up recognized in the third quarter of 2006. The 2005 increase was primarily due to higher liquids storage expenses in 2005, as discussed above.

Earnings from Products Pipelines - KMP's equity investments were $16.3 million in 2006, $28.4 million in 2005 and $29.1 million in 2004. Earnings from equity investments consist primarily of Kinder Morgan Energy Partners' approximate 51% interest in the pre-tax income of Plantation Pipe Line Company and Kinder Morgan Energy Partners' 50% interest in the net income of Heartland Pipeline Company and Johnston County Terminal, LLC. We include Kinder Morgan Energy Partners' proportionate share of Plantation's income tax expenses within "Income taxes" in the accompanying Consolidated Statements of Operations, and the interest income Kinder Morgan Energy Partners earns on loans to Plantation are reported within "Interest Expense, Net" in the accompanying Consolidated Statements of Operations.

The $12.1 million (43%) decrease in equity earnings in 2006 compared to 2005 was mainly due to lower equity earnings from Plantation, due to both a $6.6 million decrease for Kinder Morgan Energy Partners' proportionate share of Plantation's pre-tax pipeline integrity expenses that were recognized in the second half of 2006, and a $4.9 million decrease for Kinder Morgan Energy Partners' proportionate share of pre-tax environmental expenses recognized by Plantation in the second quarter of 2006. This environmental expense was related to supplemental environmental and clean-up liability adjustments associated with an April 17, 2006 pipeline release of turbine fuel from Plantation's 12-inch petroleum products pipeline located in Henrico County, Virginia.

The $0.7 million (2%) decrease in equity earnings in 2005 compared to 2004 primarily consisted of a $1.3 million (5%) decrease related to Kinder Morgan Energy Partners' investment in Plantation and a $0.8 million (55%) increase related to Kinder Morgan Energy Partners' investment in Heartland. For the investment in Plantation, the decrease was due to lower overall pre-tax income earned by Plantation, due to, among other things, higher operating expenses and higher interest expenses. For the investment in Heartland, the increase was due to Heartland's higher net income, primarily due to higher pipeline delivery volumes in 2005 versus 2004.

The segment's income from allocable interest income and other income and expense items increased $5.9 million (97%) in 2006 compared to 2005, and increased $1.4 million (31%) in 2005 compared to 2004. The 2006 increase was primarily due to the $5.7 million other income item from the favorable settlement of transmix processing contracts in the second quarter of 2006, and partly due to higher administrative overhead collected by the West Coast terminals from reimbursable projects. For 2005, the increase primarily related to incremental interest income of $2.5 million on the long-term note receivable from Plantation, as discussed above.

Income tax expenses decreased $5.2 million (50%) in 2006 compared to 2005, and decreased $1.7 million (14%) in 2005 compared to 2004. The decrease in 2006 versus 2005 was related to the lower pre-tax earnings from Cochin and Plantation, and the decrease in 2005 versus 2004 was mainly due to lower income tax on Cochin due to the decrease in Canadian operating results in 2005.

Non-cash depreciation, depletion and amortization charges, including amortization of excess cost of investments, were $86.3 million, $82.5 million and $74.5 million in each of the years ended December 31, 2006, 2005 and 2004, respectively. The $3.8 million (5%) increase in 2006 compared to 2005 was primarily due to higher depreciation expenses from the Pacific and Southeast terminal operations. The increase from the Pacific operations related to higher depreciable costs as a result of capital spending for both pipeline and storage expansion since the end of 2005 in order to strengthen and enhance the business operations on the West Coast. The increase from the Southeast terminal operations related to incremental depreciation charges resulting from final purchase price allocations, made in the fourth quarter of 2005, for depreciable terminal assets Kinder Morgan Energy Partners acquired in November 2004 from Charter Terminal Company and Charter-Triad Terminals, LLC.

The overall $8.0 million (11%) increase in depreciation expenses in 2005 compared to 2004 was primarily due to higher depreciation expenses from the Pacific operations, related to the capital investments made since the end of 2004, as well as to incremental depreciation expenses of $1.8 million related to the Southeast terminal assets Kinder Morgan Energy Partners acquired in March and November 2004.

Natural Gas Pipelines – KMP

	Year Ended December 31,		
	2006	2005	2004
	(In millions, except operating statistics)		
Revenues	$ 6,577.7	$ 7,718.4	$ 6,252.9
Operating Expenses (Including Environmental Adjustments)[a]	(6,042.6)	(7,255.0)	(5,854.6)
Earnings from Equity Investments	40.4	36.8	20.0
Interest Income and Other, Net – Income (expense)	0.8	2.7	1.8
Income taxes	(1.5)	(2.6)	(1.8)
Earnings before Depreciation, Depletion and Amortization Expense and Amortization of Excess Cost of Equity Investments	574.8	500.3	418.3
Depreciation, Depletion and Amortization Expense	(65.4)	(61.6)	(53.1)
Amortization of Excess Cost of Equity Investments	(0.3)	(0.3)	(0.3)
Segment Earnings	$ 509.1	$ 438.4	$ 364.9
Natural Gas Transport Volumes (Trillion Btus)[b]	1,440.9	1,317.9	1,353.1
Natural Gas Sales Volumes (Trillion Btus)[c]	909.3	924.6	992.4

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[a] 2006 amount includes expense of $1.5 million associated with supplemental environmental liability adjustments, a $6.2 million reduction in expense due to the release of a reserve related to a natural gas pipeline contract obligation and a gain of $15.1 million from the combined sale of our Douglas natural gas gathering system and Painter Unit fractionation

facility. 2005 and 2004 amounts include decreases in expense of $0.1 million and $7.6 million, respectively, associated with environmental liability adjustments.

[b] Includes Kinder Morgan Interstate Gas Transmission, Texas intrastate natural gas pipeline group, Trailblazer and TransColorado pipeline volumes. TransColorado annual volumes are included for all three years (acquisition date November 1, 2004).

[c] Represents Texas intrastate natural gas pipeline group.

Due to the adoption of EITF 04-5 (see Note 1(B) of the accompanying Notes to Consolidated Financial Statements), effective January 1, 2006, we include the results of operations of Kinder Morgan Energy Partners in our consolidated results of operations. Although we accounted for Kinder Morgan Energy Partners under the equity method during 2005 and 2004, for comparative purposes, the following discussion regarding the segment results of the Natural Gas Pipelines – KMP business segment includes segment results for 2006, 2005 and 2004.

The Natural Gas Pipelines – KMP segment's primary businesses involve marketing, transporting, storing, gathering and processing natural gas through both intrastate and interstate pipeline systems and related facilities. In 2006, the segment reported earnings before depreciation, depletion and amortization of $574.8 million on revenues of $6,577.7 million. This compares with earnings before depreciation, depletion and amortization of $500.3 million on revenues of $7,718.4 million in 2005 and earnings before depreciation, depletion and amortization of $418.3 million on revenues of $6,252.9 million in 2004.

Segment Earnings before Depreciation, Depletion and Amortization

The segment's overall $74.5 million (15%) increase in earnings before depreciation, depletion and amortization expenses in 2006 compared with 2005 and its $82.0 million (20%) increase in earnings before depreciation, depletion and amortization expenses in 2005 compared with 2004 included an increase of $19.8 million and a decrease of $7.6 million, respectively, from the combined net effect of the certain other items described in footnote (a) to the table above. These items consisted of the following:

- an increase in earnings of $15.1 million in 2006—due to the sale of the Douglas natural gas gathering system and Painter Unit fractionation facility in April 2006. Effective April 1, 2006, Kinder Morgan Energy Partners sold these two assets to a third party for approximately $42.5 million in cash, and we included a net gain of $15.1 million within "Other Expense (Income)" in our accompanying Consolidated Statement of Operations for 2006. For more information on this gain, see Note 5 of the accompanying Notes to Consolidated Financial Statements;

- an increase in earnings of $6.2 million in 2006—due to release of a reserve related to a natural gas purchase/sales contract associated with the operations of the West Clear Lake natural gas storage facility located in Harris County, Texas. Kinder Morgan Energy Partners acquired this storage facility as part of its acquisition of Kinder Morgan Tejas on January 31, 2002, and, upon acquisition, established a reserve for a contract liability; and

- a decrease in earnings of $1.5 million in 2006 and an increase in earnings of $7.6 million in 2004—due to changes in environmental operating expenses associated with the adjustments of our environmental liabilities as more fully described above in "Critical Accounting Policies and Estimates—Environmental Matters."

The segment's remaining $54.7 million (11%) increase in earnings before depreciation, depletion and amortization expenses in 2006 compared with 2005 was driven by higher earnings from the Texas intrastate natural gas pipeline group, primarily from improved margins resulting from the negotiation of renewal and incremental gas purchase and sales contracts, and by higher earnings from natural gas storage and processing activities. The Texas intrastate group includes the operations of the following four natural gas pipeline systems: Kinder Morgan Tejas (including Kinder Morgan Border Pipeline), Kinder Morgan Texas Pipeline, Kinder Morgan North Texas Pipeline and the Mier-Monterrey Mexico Pipeline. Combined, the group accounted for 55% of the total increase in segment earnings before depreciation, depletion and amortization in 2006 versus 2005.

The segment's remaining $89.6 million (22%) increase in earnings in 2005 compared with 2004 was mainly due to higher margins on recurring natural gas sales business and higher storage and service revenues from the Texas intrastate group, and to incremental contributions from the inclusion of the TransColorado Pipeline, a 300-mile interstate natural gas pipeline system that extends from the Western Slope of Colorado to the Blanco natural gas hub in northwestern New Mexico. Kinder Morgan Energy Partners acquired the TransColorado Pipeline from Kinder Morgan, Inc. on November 1, 2004, and the incremental amounts above relate to TransColorado's operations during the first ten months of 2005 and do not include increases or decreases during the same two months Kinder Morgan Energy Partners owned the asset in both 2005 and 2004.

Specifically, the respective remaining changes in year-to-year segment earnings before depreciation, depletion and amortization expense in 2006 versus 2005, and 2005 versus 2004, consisted of the following:

- increases of $34.6 million (13%) and $30.1 million (13%), respectively, from the Texas intrastate natural gas pipeline group—due primarily to improved margins on the group's natural gas purchase and sales activities, described above. With regard to natural gas sales activities, margin is defined as the difference between the prices at which we buy gas in our supply areas and the prices at which we sell gas in our market areas, less the cost of fuel to transport. In 2006, the Texas intrastate group's' natural gas sales margin increased $48.0 million (34%) over 2005; and in 2005, the group's' margin increased $30.7 million (28%) over 2004. The group's margin can vary depending upon, among other things, the price volatility of natural gas produced and delivered in Texas and in the surrounding Gulf Coast region, the changes in availability and demand for transportation and storage capacities, and any changes in the terms and conditions in which natural gas is purchased and sold.

  Additionally, we manage price risk associated with unfavorable changes in natural gas prices by using energy derivative contracts, such as over-the-counter forward contracts and both fixed price and basis swaps, to help lock-in favorable margins from natural gas purchase and sales activities, thereby generating more stable earnings during periods of fluctuating natural gas prices;

- increases of $10.2 million (10%) and $2.4 million (2%), respectively, from the Kinder Morgan Interstate Gas Transmission system. The increase in 2006, relative to 2005, was due largely to higher revenues earned in 2006 from both operational sales of natural gas and natural gas park and loan services. The increase in 2006 earnings from these incremental revenues more than offset a relative decrease in earnings resulting from favorable natural gas imbalance valuation adjustments recognized in 2005.

  The increase in earnings in 2005 compared to 2004 was due mainly to higher revenues from both favorable fuel recovery volumes and prices and favorable imbalance valuation adjustments. In addition, KMIGT realized lower operating expenses in 2005 compared to 2004, primarily due to the expensing, in the fourth quarter of 2004, of certain capitalized project costs that no longer held realizable economic benefits. The increase in revenues in 2005 versus 2004 was partially offset by lower margins on operational gas sales and reduced cushion gas volumes sold;

- increases of $4.3 million (13%) and $17.3 million (119%), respectively, from Kinder Morgan Energy Partners' 49% equity investment in Red Cedar Gathering Company—due largely to higher natural gas gathering revenues and to higher prices on incremental sales of excess fuel gas. Additionally, since the end of 2004, Kinder Morgan Energy Partners reduced the amount of natural gas lost and used within the system during gathering operations, which in turn has increased natural gas volumes available for sale;

- increases of $3.8 million (10%) and $33.4 million respectively, from the TransColorado Pipeline—the 2006 increase was largely due to higher natural gas transmission revenues earned in 2006 compared to 2005. The revenue increase related to higher natural gas delivery volumes resulting from both system improvements and the successful negotiation of incremental firm transportation contracts. The pipeline system improvements were associated with an expansion, completed since the end of the first quarter of 2005, on the northern portion of the pipeline. TransColorado's north system expansion project was in-service on January 1, 2006, and provides for up to 300 million cubic feet per day of additional northbound transportation capacity. The overall increase in earnings in 2005 compared to 2004 was primarily due to incremental earnings of $31.8 million, representing TransColorado's earnings before depreciation, depletion and amortization expenses in the first ten months of 2005 (after acquiring the pipeline on November 1, 2004);

- an increase of $2.3 million (21%) and a decrease of $5.1 million (32%), respectively, from the combined operations of the Casper Douglas and Painter natural gas gathering and processing operations. The 2006 increase in earnings was primarily related to incremental earnings associated with favorable hedge settlements from the Casper Douglas natural gas gathering and processing operations. Kinder Morgan Energy Partners benefited from comparative differences in hedge settlements associated with the rolling-off of older low price crude oil and propane positions at December 31, 2005. The 32% decrease in earnings in 2005 versus 2004 was mainly due to higher cost of sales expense and higher commodity hedging costs in 2005. The higher cost of sales expense reflected higher natural gas purchase costs, due to higher average gas prices in 2005. The higher commodity hedging costs was chiefly due to unfavorable changes in settlement prices;

- increases of $0.3 million (1%) and $10.9 million (28%), respectively, from the Trailblazer Pipeline—due primarily to timing differences on the settlements of pipeline transportation imbalances in 2006 and 2005, compared to the respective year-earlier periods. These pipeline imbalances are due to differences between the volumes received and the volumes delivered at inter-connecting points on the pipeline, and generally, the imbalances are either settled in cash or made up in kind subject to both the pipelines' various tariff provisions and operational balancing agreements with shippers. The increase in earnings in 2006 compared to 2005 was also due to incremental sales of operational natural gas in the fourth quarter of 2006, largely related to timing differences; and

- a decrease of $0.8 million (13%) and an increase of $0.5 million (9%), respectively, from the combined earnings of the remaining natural gas operations, including Kinder Morgan Energy Partners' previous 50% investment in Coyote Gas Treating, LLC and Kinder Morgan Energy Partners' 25% investment in Thunder Creek Gas Services, LLC—the decrease in 2006 was due to both the absence of equity earnings from Kinder Morgan Energy Partners' investment in Coyote and to lower natural gas gathering income from Thunder Creek. Effective September 1, 2006, Kinder Morgan Energy Partners and the Southern Ute Indian Tribe contributed the value of their respective 50% ownership interests in Coyote Gas Treating, LLC to Red Cedar, and as a result, Coyote Gas Treating, LLC became a wholly owned subsidiary of Red Cedar.

  The increase in earnings in 2005 compared to 2004 was largely due to incremental interest income from Kinder Morgan Energy Partners' long-term note receivable from Coyote. In 2005, Kinder Morgan Energy Partners allocated this interest income to the Natural Gas Pipelines - KMP business segment, versus treating it as unallocated interest income in 2004. In March 2006, Kinder Morgan Energy Partners contributed the principal amount of $17.0 million related to this note to its equity investment in Coyote.

Segment Details

In 2006, total segment operating revenues, including revenues from natural gas sales, decreased $1,140.7 million (15%) compared to 2005, and combined operating expenses, including natural gas purchase costs, decreased $1,212.3 million (17%). In 2005, the segment reported significant increases in both revenues and operating expenses when compared to the year-earlier period—revenues increased $1,465.5 million (23%) and operating expenses increased $1,400.4 million (24%). The year-to-year changes in total segment revenues and total segment operating expenses largely represented the respective changes in the Texas intrastate group's natural gas sales revenues and natural gas purchase expenses, due primarily to year-over-year changes in natural gas prices.

The Intrastate group's purchase and sale activities result in considerably higher revenues and operating expenses compared to the interstate operations of the Rocky Mountain pipelines, which include the KMIGT, Trailblazer and TransColorado pipelines. All three pipelines charge a transportation fee for gas transmission service and have the authority to initiate natural gas sales primarily for operational purposes, but none engage in significant gas purchases for resale. Kinder Morgan Energy Partners did, however, realize incremental revenues of $36.2 million and incremental operating expenses of $4.5 million from the ownership of the TransColorado Pipeline in the first ten months of 2005.

As discussed above, the Texas intrastate group both purchases and sells significant volumes of natural gas. Compared to the respective prior year, revenues from the sales of natural gas from the Intrastate group decreased $1,154.4 million (16%) in 2006, and increased $1,404.1 million (24%) in 2005; similarly, the group's costs of sales expense, including natural gas purchase costs, decreased $1,202.4 million (17%) in 2006, and increased $1,373.4 million (24%) in 2005.

Since the Texas intrastate group sells natural gas in the same price environment in which it is purchased, any increases in its gas purchase costs are largely offset by corresponding increases in its sales revenues. Due to this offsetting of revenues and expenses, we believe that margin is a better comparative performance indicator than either revenues or cost of sales, and our objective is to match purchases and sales in the aggregate, and to lock-in an acceptable margin by capturing the difference between our average gas sales prices and our average gas purchase and cost of fuel prices. Our strategy involves relying mainly on long-term natural gas sales and purchase agreements, with some purchases and sales being made in the spot market in order to provide some flexibility to balance supply and demand in reaction to changing market conditions.

The Texas intrastate groups' natural gas sales margin increased $48.0 million (34%) and $30.7 million (28%), respectively, in 2006 and 2005, when compared to the year-earlier period. The variations in natural gas sales margin were driven by changes in natural gas prices and sales volumes—the $48.0 million margin increase in 2006 consisted of a $59.3 million increase from favorable changes in average sales versus average purchase prices (favorable price variance), and a $11.3 million decrease from lower volumes (unfavorable volume variance)—the $30.7 million margin increase in 2005 consisted of a $40.0 million increase from favorable changes in average sales prices versus average purchase prices, and a $9.3 million decrease from lower volumes. Also, the intrastate groups' margins from natural gas processing activities increased $10.1 million (53%) in 2006 compared to 2005, and decreased $3.8 million (17%) in 2005 compared to 2004.

Kinder Morgan Energy Partners accounts for the segment's investments in Red Cedar Gathering Company, Thunder Creek Gas Services, LLC, and prior to September 1, 2006, Coyote Gas Treating, LLC under the equity method of accounting. Combined earnings from these three investees increased $3.6 million (10%) and $16.9 million (84%), respectively, in 2006 and 2005, when compared to year-earlier periods. The increases were chiefly due to higher net income earned by Red Cedar during 2006 and 2005, partially offset by lower net income from the combined investments in Coyote Gas Treating LLC and Thunder Creek Gas Services, LLC, all discussed above.

The segment's combined interest income and earnings from other income items (Other, Net) decreased $2.0 million (72%) in

2006 compared to 2005, and increased $0.9 million in 2005 compared to 2004. The 2006 decrease was chiefly due to a gain from a property disposal by the Kinder Morgan Tejas Pipeline in the third quarter of 2005. The 2005 increase was mainly due to the allocation of interest income earned, in 2005, on Kinder Morgan Energy Partners' note receivable from Coyote Gas Treating, LLC. Income tax expenses changed slightly over both 2006 and 2005—decreasing $1.2 million (46%) in 2006, and increasing $0.7 million (38%) in 2005, when compared to prior years. The changes primarily related to tax accrual adjustments related to the operations of the Mier-Monterrey Mexico Pipeline.

The segment's non-cash depreciation, depletion and amortization charges, including amortization of excess cost of investments increased $3.7 million (6%) in 2006 compared to 2005, and increased $8.5 million (16%) in 2005 compared to 2004. The 2006 increase was largely attributable to higher year-to-year depreciation expenses from the Texas intrastate natural gas pipeline group, due both to incremental capital spending during 2006, and to additional depreciation charges related to the group's acquisition of the North Dayton, Texas natural gas storage facility in August 2005. The 2005 increase was due to incremental depreciation expenses of $4.2 million from the inclusion of the acquired TransColorado Pipeline, and higher depreciation expenses on the assets of the Texas intrastate natural gas pipeline group, due to additional capital investments made since the end of 2004.

CO_2 – KMP

	Year Ended December 31,		
	2006	**2005**	**2004**
	(In millions, except operating statistics)		
Revenues[a]	$ 736.5	$ 657.6	$ 492.8
Operating Expenses (Including Environmental Adjustments)[b]	(268.1)	(212.6)	(169.3)
Earnings from Equity Investments	19.2	26.3	34.2
Other, Net – Income (Expense)	0.8	–	–
Income Taxes	(0.2)	(0.4)	(0.1)
Earnings before Depreciation, Depletion and Amortization Expense and Amortization of Excess Cost of Equity Investments	488.2	470.9	357.6
Depreciation, Depletion and Amortization Expense[c]	(191.0)	(149.9)	(121.3)
Amortization of Excess Cost of Equity Investments	(2.0)	(2.0)	(2.0)
Segment Earnings	$ 295.2	$ 319.0	$ 234.3
Carbon Dioxide Delivery Volumes (Bcf)[d]	669.2	649.3	640.8
SACROC Oil Production (Gross)(MBbl/d)[e]	30.8	32.1	28.3
SACROC Oil Production (Net)(MBbl/d)[f]	25.7	26.7	23.6
Yates Oil Production (Gross)(MBbl/d)[e]	26.1	24.2	19.5
Yates Oil Production (Net)(MBbl/d)[f]	11.6	10.8	8.6
Natural Gas Liquids Sales Volumes (Net)(MBbl/d)[f]	8.9	9.4	7.7
Realized Weighted Average Oil Price per Bbl[g, h]	$ 31.42	$ 27.36	$ 25.72
Realized Weighted Average Natural Gas Liquids Price per Bbl[h, i]	$ 43.90	$ 38.98	$ 31.33

[a] 2006 includes a $1.8 million loss on derivative contracts used to hedge forecasted crude oil sales.

[b] Includes expense of $0.3 million in 2005 and a decrease in expense of $4.1 million in 2004 associated with environmental liability adjustments.

[c] Includes depreciation, depletion and amortization expense associated with oil and gas producing and gas processing activities in the amount of $171.3 million for 2006, $132.3 million for 2005, and $105.9 million for 2004. Includes depreciation, depletion and amortization expense associated with sales and transportation services activities in the amount of $19.6 million for 2006, $17.6 million for 2005, and $15.5 million for 2004.

[d] Includes Cortez, Central Basin, Canyon Reef Carriers, Centerline and Pecos pipeline volumes.

[e] Represents 100% of the production from the field. We own an approximate 97% working interest in the SACROC unit and an approximate 50% working interest in the Yates unit.

[f] Net to Kinder Morgan, after royalties and outside working interests.

[g] Includes all Kinder Morgan crude oil production properties.

[h] Hedge gains/losses for crude oil and natural gas liquids are included with crude oil.

[i] Includes production attributable to leasehold ownership and production attributable to our ownership in processing plants and third party processing agreements.

Due to the adoption of EITF 04-5 (see Note 1(B) of the accompanying Notes to Consolidated Financial Statements), effective January 1, 2006, we include the results of operations of Kinder Morgan Energy Partners in our consolidated results of operations. Although we accounted for Kinder Morgan Energy Partners under the equity method during 2005 and 2004, for comparative purposes, the following discussion regarding the segment results of the CO_2 – KMP business segment includes segment results for 2006, 2005 and 2004.

The CO_2 segment consists of Kinder Morgan CO_2 Company, L.P. and its consolidated affiliates. The segment's primary businesses involve the production, marketing and transportation of both carbon dioxide (commonly called CO_2) and crude oil, and the production and marketing of natural gas and natural gas liquids. In 2006, the CO_2 segment reported earnings before depreciation, depletion and amortization of $488.2 million on revenues of $736.5 million. This compares with earnings before depreciation, depletion and amortization of $470.9 million on revenues of $657.6 million in 2005, and earnings before depreciation, depletion and amortization of $357.6 million on revenues of $492.8 million in 2004.

The segment's overall $17.3 million (4%) increase in earnings before depreciation, depletion and amortization expenses in 2006 compared with 2005 and its $113.3 million (32%) increase in earnings before depreciation, depletion and amortization expenses in 2005 compared with 2004 included decreases of $1.5 million and $4.4 million, respectively, from the combined net effect of the certain other items described in footnotes (a) and (b) to the table above. These items consisted of the following:

- a decrease in earnings of $1.8 million in 2006—due to a $1.8 million loss on derivative contracts used to hedge forecasted crude oil sales; and

- a decrease in earnings of $0.3 million in 2005 and an increase in earnings of $4.1 million in 2004—due to changes in environmental operating expenses associated with the adjustments of our environmental liabilities.

The segment's remaining $18.8 million (4%) increase in earnings before depreciation, depletion and amortization expenses in 2006 compared with 2005 was driven by higher earnings from the segment's carbon dioxide sales and transportation activities; the remaining $117.7 million (33%) increase in earnings before depreciation, depletion and amortization expenses in 2005 compared with 2004 was primarily due to higher earnings from the segment's oil and gas producing activities.

Segment Earnings before Depreciation, Depletion and Amortization

Sales and Transportation Activities

The segment's carbon dioxide sales and transportation activities reported earnings before depreciation, depletion and amortization of $186.8 million in 2006, $162.4 million in 2005, and $123.6 million in 2004. The increases in earnings were driven by higher revenues—from both carbon dioxide sales and deliveries, and from crude oil pipeline transportation. The overall increases were partly offset by lower equity earnings from the segment's 50% ownership interest in Cortez Pipeline Company.

The increases in carbon dioxide sales revenues were due to both higher average prices and higher sales volumes. Correlating closely with the increase in crude oil prices since the end of 2004, average carbon dioxide sales prices increased 18% and 44%, respectively, in 2006 and 2005, when compared to the prior year. In addition, we did not use derivative contracts to hedge or help manage the financial impacts associated with the increases in carbon dioxide prices, and as always, we did not recognize profits on carbon dioxide sales to ourselves.

The increases in volumes were largely attributable to the continued strong demand for carbon dioxide from tertiary oil recovery projects in the Permian Basin area since the end of 2004, and to increased carbon dioxide production from the McElmo Dome source field. Kinder Morgan Energy Partners operates and owns a 45% interest in McElmo Dome, which supplies carbon dioxide to oil recovery fields in the Permian Basin of southeastern New Mexico and West Texas. Combined deliveries of carbon dioxide on the Central Basin Pipeline, the majority-owned Canyon Reef Carriers and Pecos Pipelines, the Centerline Pipeline, and the 50% owned Cortez Pipeline, which is accounted for under the equity method of accounting, increased 3% in 2006 and 1% in 2005, when compared to the respective prior years.

The increases in revenues from carbon dioxide and crude oil transportation were due to higher delivery volumes and higher rates. The increase in volumes was largely related to infrastructure expansions at the SACROC and Yates oil field units. The SACROC and Yates units are the two largest oil field units in which Kinder Morgan Energy Partners holds ownership interests—these interests include the approximate 97% working interest in the SACROC unit, located in Scurry County, Texas, and the approximate 50% working interest in the Yates unit, located south of Midland, Texas.

In 2005, Kinder Morgan Energy Partners also benefited from the acquisition of the Kinder Morgan Wink Pipeline, a 450-mile crude oil pipeline system originating in the Permian Basin of West Texas and providing throughput to a crude oil refinery located in El Paso, Texas. Effective August 31, 2004, Kinder Morgan Energy Partners acquired all of the partnership interests in Kinder Morgan Wink Pipeline, L.P. for $89.9 million in cash and the assumption of $10.4 million in liabilities. The acquisition of the pipeline and associated storage facilities allowed Kinder Morgan Energy Partners to better manage crude oil deliveries from its oil field interests in West Texas. During the first eight months of 2005, the Kinder Morgan Wink Pipeline accounted for incremental earnings before depreciation, depletion and amortization of $13.4 million, revenues of $16.7 million and operating expenses of $3.3 million.

Oil and Gas Producing Activities

The remaining changes in year-to-year segment earnings before depreciation, depletion and amortization—a decrease of $7.1 million (2%) in 2006 versus 2005, and an increase of $74.5 million (32%) in 2005 versus 2004, were attributable to the segment's crude oil and natural gas producing activities, which also include its natural gas processing activities. These operations include all construction, drilling and production activities necessary to produce oil and gas from its natural reservoirs, and all of the activities where natural gas is processed to extract liquid hydrocarbons, called natural gas liquids or commonly referred to as gas plant products. Combined, the CO_2 – KMP segment's oil and gas producing and gas processing activities reported earnings before depreciation, depletion and amortization of $301.4 million in 2006, $308.5 million in 2005, and $234.0 million in 2004.

In both 2006 and 2005, Kinder Morgan Energy Partners made significant capital investments to increase the capacity and deliverability of carbon dioxide and crude oil in and around the Permian Basin. These investments were made in order to benefit from rising price trends for energy commodity products and from continued strong demand for carbon dioxide from tertiary oil recovery projects, which commonly inject carbon dioxide into reservoirs adjacent to producing crude oil wells. Once injected into the reservoir, the carbon dioxide gas often enhances crude oil recovery in two ways—first, by expanding and pushing additional oil to the production wellbore, and secondly, by dissolving into the oil in order to lower its viscosity and improve its flow rate. In 2006, capital expenditures for the CO_2 – KMP business segment totaled $283.0 million; this compares with capital expenditures of $302.1 million in 2005 and $302.9 million in 2004. The expenditures primarily represent incremental spending for new well and injection compression facilities at the SACROC and, to a lesser extent, Yates oil field units.

The year-over-year $7.1 million (2%) decrease in earnings in 2006 compared to 2005 was primarily due to higher combined operating expenses and to an expected drop in crude oil production at the SACROC oil field unit. The higher operating expenses included higher field operating and maintenance expenses (including well workover expenses), higher property and severance taxes, and higher fuel and power expenses. The increases in expenses more than offset higher overall crude oil and natural gas plant product sales revenues, which increased primarily from higher realized sales prices and partly from higher crude oil production at the Yates oil field unit. The year-over-year increase in earnings of $74.5 million (32%) in 2005 compared to 2004 was primarily driven by increased crude oil and natural gas processing plant liquids production volumes, and by higher realized weighted average sale prices for crude oil and gas plant products.

The year-to-year decline in crude oil production at the SACROC unit in 2006 was announced in the first quarter of 2006. At that time, we used information obtained from production performance to change our previous estimates of proved crude oil reserves at SACROC; however, due to the fact that the decrease in production is largely specific to one section of the field that is underperforming, we do not expect this reserve revision to have a material impact on our financial statements or capital spending in future periods. For more information on Kinder Morgan Energy Partners' ownership interests in the net quantities of proved oil and gas reserves and the measures of discounted future net cash flows from oil and gas reserves.

As a result of Kinder Morgan Energy Partners' carbon dioxide and oil reserve ownership interests, it are exposed to commodity price risk associated with physical crude oil and natural gas liquids sales; however this price risk is mitigated through a long-term hedging strategy that uses derivative contracts to reduce the impact of unpredictable changes in crude oil and natural gas liquids sales prices. The goal is to use derivative contracts in order to prevent or reduce the possibility of future losses, and to generate more stable realized prices. Our hedging strategy involves the use of financial derivative contracts to manage this price risk on certain activities, including firm commitments and anticipated transactions for the sale of crude oil and natural gas liquids. Our strategy, as it relates to Kinder Morgan Energy Partners' oil production business, primarily involves entering into a forward sale or, in some cases, buying a put option in order to establish a known price level. In this way, we use derivative contracts to lock in an acceptable margin between Kinder Morgan Energy Partners' production costs and the selling price, in an attempt to protect against the risk of adverse price changes and to maintain a more stable and predictable earnings stream.

Had we not used energy derivative contracts to transfer commodity price risk, Kinder Morgan Energy Partners' crude oil sales prices would have averaged $63.27 per barrel in 2006, $54.45 per barrel in 2005 and $40.91 per barrel in 2004. In periods of rising prices for crude oil and natural gas liquids, we often surrender profits that would result from period-to-period price increases. We believe, however, that our use of derivative contracts protects Kinder Morgan Energy Partners' unitholders from unpredictable adverse events. All of Kinder Morgan Energy Partners' hedge gains and losses for crude oil and natural gas liquids are included in its realized average price for oil; none are allocated to natural gas liquids. For more information on our hedging activities, see Note 12 of the accompanying Notes to Consolidated Financial Statements.

Segment Details

Including the $1.8 million hedge ineffectiveness loss in 2006, the CO_2 – KMP segment's revenues increased $78.9 million (12%) in 2006 compared to 2005, and $164.8 million (33%) in 2005 compared to 2004. The respective year-over-year increases were primarily due to the following:

- increases of $56.0 million (15%) and $71.7 million (23%), respectively, from crude oil sales—attributable to increases of 15% and 6%, respectively, in the realized weighted average price of crude oil and, in 2005, to a 16% increase in year-over-year sales volumes. The overall crude oil sales volumes were flat across both 2006 and 2005. On a gross basis, meaning total quantity produced, combined daily oil production from the SACROC and Yates units increased 1% in 2006 compared to 2005, and 18% in 2005 compared to 2004. In 2006, a 4% drop in crude oil production at SACROC was offset by an 8% increase in oil production at the Yates oil field unit. In 2005, gross crude oil production increased 13% at SACROC and 24% at Yates, when compared to 2004;

- increases of $14.6 million (28%) and $26.1 million (103%), respectively, from carbon dioxide sales—due mainly to higher average sales prices, discussed above, and to year-over-year increases of 7% in sales volumes in both 2006 and 2005;

- increases of $8.9 million (15%) and $18.0 million (44%), respectively, from carbon dioxide and crude oil pipeline transportation revenues—due largely to increases in system-wide carbon dioxide delivery volumes and, in 2005, to incremental crude oil transportation revenues from the Kinder Morgan Wink Pipeline;

- increases of $7.9 million (6%) and $45.1 million (51%), respectively, from natural gas liquids sales—reflecting increases of 13% and 24%, respectively, in the realized weighted average natural gas liquids price per barrel. In 2005, Kinder Morgan Energy Partners also benefited from a 22% increase in liquids processing volumes, as compared to 2004, primarily due to the capital expenditures and infrastructure improvements made since the end of 2004. The 2006 increase in natural gas liquids sales was partially offset by a 5% decrease in sales volumes, primarily related to the lower crude oil production at SACROC; and

- decreases of $10.4 million (72%) and $1.5 million (9%), respectively, from natural gas sales—due entirely to lower year-over-year sales volumes. The decreases in volumes were mainly attributable to lower volumes of gas available for sale since the second quarter of 2005, due partly to the overall declining production at the SACROC field and partly to natural gas volumes used at the power plant Kinder Morgan Energy Partners constructed at the SACROC oil field unit and placed in service in June 2005.

  Construction of the plant began in mid-2004, and the project was completed at a cost of approximately $76 million. Kinder Morgan Energy Partners constructed the SACROC power plant in order to reduce its purchases of electricity from third-parties, but it reduces its sales of natural gas because some natural gas volumes are consumed by the plant. The power plant now provides approximately half of SACROC's current electricity needs. Kinder Morgan, Inc. operates and maintains the power plant under a five-year contract expiring in June 2010, and Kinder Morgan Energy Partners reimburses Kinder Morgan, Inc. for its operating and maintenance costs.

Compared to the respective prior years, the segment's operating expenses increased $55.5 million (26%) in 2006 and $43.4 million (26%) in 2005. The increases consisted of the following:

- increases of $35.3 million (36%) and $7.7 million (9%), respectively, from combined cost of sales and field operating and maintenance expenses—largely due to additional labor and field expenses, including well workover expenses, related to infrastructure expansions at the SACROC and Yates oil field units since the end of 2004. Workover expenses relate to incremental operating and maintenance charges incurred on producing wells in order to restore or increase production, and are often performed in order to stimulate production, add pumping equipment, remove fill from the wellbore, or mechanically repair the well.

  Oil and gas operations, coupled with carbon dioxide flooding, often require a high level of investment, including ongoing expenses for facility upgrades, wellwork and drilling. Kinder Morgan Energy Partners continues to aggressively pursue opportunities to drill new wells and/or expand existing wells for both carbon dioxide and crude oil in order to benefit from robust demand for energy commodities in and around the Permian Basin area. In some cases, the cost of carbon dioxide that is associated with enhanced oil recovery is capitalized as part of the development costs when it is injected. The carbon dioxide costs incurred and capitalized as development costs for the CO_2 segment were \$100.5 million, \$74.7 million and \$70.6 million for the years ended December 31, 2006, 2005 and 2004, respectively;

- increases of \$13.8 million (19%) and \$16.0 million (28%), respectively, from fuel and power expenses—due to increased carbon dioxide compression and equipment utilization, higher fuel costs, and higher electricity expenses due to higher rates as a result of higher fuel costs to electricity providers. Overall higher electricity costs were partly offset, however, by the benefits provided from the power plant Kinder Morgan Energy Partners constructed at the SACROC oil field unit;

- increases of \$6.7 million (16%) and \$15.3 million (56%), respectively, from taxes, other than income taxes—attributable mainly to higher property and production (severance) taxes. The higher property taxes related to both increased asset infrastructure and higher assessed property values since the end of 2004. The higher severance taxes, which are primarily based on the gross wellhead production value of crude oil and natural gas, were driven by the higher period-to-period crude oil revenues; and

- a decrease of \$0.3 million and an increase of \$4.4 million, respectively, due to changes in environmental operating expenses associated with the adjustments of our environmental liabilities.

Earnings from equity investments, representing equity earnings from the 50% ownership interest in the Cortez Pipeline Company, decreased \$7.1 million (27%) in 2006 compared to 2005, and \$7.9 million (23%) in 2005 compared to 2004. Cortez owns and operates an approximate 500-mile pipeline that carries carbon dioxide from the McElmo Dome source reservoir to the Denver City, Texas carbon dioxide hub. The decreases in equity earnings were due to lower year-over-year net income earned by Cortez since 2004, mainly as a result of lower carbon dioxide transportation revenues. The decreases in transportation revenues resulted from lower year-to-year average tariff rates, which more than offset incremental revenues realized as a result of higher carbon dioxide delivery volumes. The decreases in tariff rates were expected because Kinder Morgan Energy Partners benefited from higher tariffs in prior years, when tariffs were set higher in order to make up for under-collected revenues.

Non-cash depreciation, depletion and amortization charges, including amortization of excess cost of equity investments, increased \$41.0 million (27%) in 2006 compared to 2005, and \$28.5 million (23%) in 2005 compared to 2004. The increases were due to both higher depreciable costs, as a result of incremental capital spending since the end of 2004, and higher combined depreciation and depletion charges, related to year-over-year increases in crude oil production volumes. In 2006, Kinder Morgan Energy Partners also realized incremental depreciation charges of \$3.4 million attributable to the various oil and gas properties acquired in April 2006 from Journey Acquisition – I, L.P. and Journey 2000, L.P.

The increase in depreciation expenses in 2006 compared to 2005 was also due to a higher unit-of-production depletion rate used in 2006, related to changes in estimated oil and gas reserves at the SACROC oil field unit. The capitalized costs of proved oil and gas properties must be amortized by the unit of production method so that each unit produced is assigned a pro rata portion of the unamortized costs. These amortization rates must be revised at least annually, but are also adjusted if there is an indication that total estimated units are different than previously estimated.

Terminals – KMP

	Year Ended December 31,		
	2006	2005	2004
	(In millions, except operating statistics)		
Revenues	$ 864.8	$ 699.3	$ 541.8
Operating Expenses (Including Environmental Adjustments)[a]	(446.8)	(373.4)	(254.1)
Earnings from Equity Investments	0.2	0.1	-
Other, Net – Income (Expense)	2.1	(0.3)	(0.4)
Income Taxes[b]	(12.2)	(11.1)	(5.6)
Earnings Before Depreciation, Depletion and Amortization Expense and Amortization of Excess Cost of Equity Investments	408.1	314.6	281.7
Depreciation, Depletion and Amortization Expense	(74.5)	(59.1)	(42.9)
Amortization of Excess Cost of Equity Investments	–	–	–
Segment Earnings	$ 333.6	$ 255.5	$ 238.8
Bulk Transload Tonnage (MMtons)[c]	89.5	85.5	84.1
Liquids Leaseable Capacity (MMBbl)	43.5	42.4	36.8
Liquids Utilization %	96.3%	95.4%	96.0%

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[a] 2006 amount includes and increase in expense of $2.8 million related to hurricane clean-up and repair activities, and a gain of $15.2 million from property casualty indemnifications. Also, includes an increase in expense of $3.5 million in 2005 and a decrease in expense of $18.7 million in 2004 associated with environmental liability adjustments.

[b] 2006 amount includes expense of $1.1 million associated with hurricane expenses and casualty gain. 2004 amount includes expense of $0.1 million associated with environmental liability adjustments.

[c] Volumes include all acquired terminals.

Due to the adoption of EITF 04-5 (see Note 1(B) of the accompanying Notes to Consolidated Financial Statements), effective January 1, 2006, we include the results of operations of Kinder Morgan Energy Partners in our consolidated results of operations. Although we accounted for Kinder Morgan Energy Partners under the equity method during 2005 and 2004, for comparative purposes, the following discussion regarding the segment results of the Terminals – KMP business segment includes segment results for 2006, 2005 and 2004.

The Terminals – KMP segment includes the operations of Kinder Morgan Energy Partners' petroleum and petrochemical-related liquids terminal facilities (other than those included in the Products Pipelines – KMP segment), and all of Kinder Morgan Energy Partners' coal, petroleum coke, steel and other dry-bulk material services facilities. Refining, manufacturing, mining and quarrying companies worldwide depend on these facilities to provide liquids and bulk handling services, transload, engineering, and other in-plant services to supply marine, rail, truck, temporary storage, and other distribution means needed to move dry-bulk, bulk petroleum, and chemicals across the United States. The segment reported earnings before depreciation, depletion and amortization of $408.1 million on revenues of $864.8 million in 2006. This compares with earnings before depreciation, depletion and amortization of $ 314.6 million on revenues of $699.3 million in 2005 and earnings before depreciation, depletion and amortization of $281.7 million on revenues of $541.9 million in 2004.

The segment's overall $93.5 million (30%) increase in earnings before depreciation, depletion and amortization expenses in 2006 compared with 2005 and its $32.9 million (12%) increase in earnings before depreciation, depletion and amortization expenses in 2005 compared with 2004, included an increase of $14.8 million and a decrease of $22.1 million, respectively, from the combined net effect of the certain other items described in footnotes (a) and (b) to the table above. These items consisted of the following:

- an increase in earnings of $11.3 million in 2006—from the combined effect of a gain from the settlement of property casualty insurance claims and incremental repair and clean-up expenses, both related to the 2005 hurricane season. In the third quarter of 2005, Hurricane Katrina struck the Louisiana-Mississippi Gulf Coast, and Hurricane Rita struck the Texas-Louisiana Gulf Coast, causing wide-spread damage to both residential and commercial property. The assets Kinder Morgan Energy Partners operates that were impacted by the storm included several bulk and liquids terminal facilities located in the States of Louisiana, Mississippi and Texas. Primarily affected was the International Marine Terminals facility, a Louisiana partnership owned 66 2/3% by Kinder Morgan Energy Partners. IMT is a multi-purpose bulk commodity transfer terminal facility located in Port Sulphur, Louisiana.

The $11.3 million increase in segment earnings consisted of: (i) a $15.2 million property casualty gain; (ii) a $2.8 million increase in operating and maintenance expenses from hurricane repair and recovery activities; and (iii) a $1.1 million increase in income tax expense associated with the segment's overall hurricane income and expense items. Including an additional $0.4 million decrease in general and administrative expenses, and a $3.1 million increase in minority interest expense, both related to hurricane activity, total hurricane income and expense items increased Kinder Morgan Energy Partners' net income by $8.6 million in 2006; and

- a decrease in earnings of $3.5 million in 2005 and an increase in earnings of $18.6 million in 2004—due to changes in environmental operating expenses associated with the adjustments of our environmental liabilities.

The segment's remaining $78.7 million (4%) increase in earnings before depreciation, depletion and amortization expenses in 2006 compared with 2005, and its remaining $55.0 million (21%) increase in 2005 compared to 2004 were driven by a combination of internal expansions and strategic acquisitions. Kinder Morgan Energy Partners makes and continues to seek key terminal acquisitions in order to gain access to new markets, to complement and/or enlarge its existing terminal operations, and to benefit from the economies of scale resulting from increases in storage, handling and throughput capacity.

Segment Earnings before Depreciation, Depletion and Amortization

Kinder Morgan Energy Partners' significant terminal acquisitions since the beginning of 2005 included the following:

- the Texas Petcoke terminals, located in and around the Ports of Houston and Beaumont, Texas, acquired effective April 29, 2005;
- three terminals acquired separately in July 2005: the Kinder Morgan Staten Island terminal, a dry-bulk terminal located in Hawesville, Kentucky and a liquids/dry-bulk facility located in Blytheville, Arkansas;
- all of the ownership interests in General Stevedores, L.P., which operates a break-bulk terminal facility located along the Houston Ship Channel, acquired July 31, 2005;
- the Kinder Morgan Blackhawk terminal located in Black Hawk County, Iowa, acquired in August 2005;
- a terminal-related repair shop located in Jefferson County, Texas, acquired in September 2005;
- three terminal operations acquired separately in April 2006: terminal equipment and infrastructure located on the Houston Ship Channel, a rail terminal located at the Port of Houston, and a rail ethanol terminal located in Carson, California; and
- all of the membership interests of Transload Services, LLC, which provides material handling and steel processing services at 14 steel-related terminal facilities located in the Chicago metropolitan area and various cities in the United States, acquired November 20, 2006.

Kinder Morgan Energy Partners has invested approximately $305.5 million in cash and $49.6 million in common units to acquire these terminal assets and combined, these operations accounted for incremental amounts of earnings before depreciation, depletion and amortization of $33.5 million, revenues of $68.8 million and operating expenses of $35.3 million, respectively, in 2006. A majority of these increases in earnings, revenues and expenses from terminal acquisitions were attributable to the inclusion of the Texas petroleum coke terminals and repair shop assets, which Kinder Morgan Energy Partners acquired from Trans-Global Solutions, Inc. on April 29, 2005 for an aggregate consideration of approximately $247.2 million. The primary assets acquired included facilities and railway equipment located at the Port of Houston, the Port of Beaumont and the TGS Deepwater terminal located on the Houston Ship Channel. Combined, these operations accounted for incremental amounts of earnings before depreciation, depletion and amortization of $16.8 million, revenues of $31.0 million and operating expenses of $14.2 million, respectively, in 2006.

For 2005, Kinder Morgan Energy Partners benefited significantly from the incremental contributions attributable to the bulk and liquids terminal businesses acquired since the end of the third quarter of 2004. In addition to the 2005 acquisitions referred to above, these acquisitions included:

- the river terminals and rail transloading facilities owned and operated by Kinder Morgan River Terminals LLC and its consolidated subsidiaries, acquired effective October 6, 2004; and
- the Kinder Morgan Fairless Hills terminal located along the Delaware River in Bucks County, Pennsylvania, acquired effective December 1, 2004.

Combined, terminal operations acquired since the end of the third quarter of 2004 accounted for incremental amounts of earnings before depreciation, depletion and amortization of $45.5 million, revenues of $113.8 million and operating expenses of $65.0 million, respectively, in 2005. All of the incremental amounts listed above for both 2006 and 2005, represent the earnings, revenues and expenses from the acquired terminals' operations during the additional months of ownership in 2006, and 2005, respectively, and do not include increases or decreases during the same months Kinder Morgan Energy Partners owned the assets in 2005 and 2004, respectively. For more information in regard to Kinder Morgan Energy Partners' terminal acquisitions, see Note 4 of the accompanying Notes to Consolidated Financial statements.

Terminal Operations Owned During Both Comparable Years

For all other terminal operations (those owned during the same months of both comparable years), earnings before depreciation, depletion and amortization increased $60.0 million (19%) in 2006 compared to 2005, and decreased $12.6 million (4%) in 2005 compared to 2004; however, as described above, the net effect of the property casualty gain, hurricane repair expenses (net of income tax), and environmental liability adjustments resulted in a $14.8 million increase in earnings before depreciation, depletion and amortization in 2006 relative to 2005, and a $22.1 million decrease in 2005 relative to 2004. The remaining change in the earnings before depreciation, depletion and amortization expenses from terminal operations owned during both years consisted of a $45.2 million (14%) increase in 2006 compared to 2005, and a $9.5 million (4%) increase in 2005 compared to 2004. These respective year-to-year increases in earnings primarily consisted of the following:

- increases of $17.4 million (23%) and $13.7 million (22%), respectively, from the Gulf Coast region. This region includes the operations of the two large Gulf Coast liquids terminal facilities located along the Houston Ship Channel in Pasadena and Galena Park, Texas. The two terminals serve as a distribution hub for Houston's crude oil refineries, and since the end of 2004, have contributed incremental earnings attributable to internal growth complemented by the completion of expansion projects undertaken to increase leaseable liquids capacity.

  The year-over-year increase in earnings in 2006 versus 2005 was primarily revenue related, driven by increases from new and incremental customer agreements, additional liquids tank capacity from capital expansions at the Pasadena terminal since the end of 2005, higher truck loading rack service fees, higher ethanol throughput, and incremental revenues from customer deficiency charges.

  Since the end of 2004, Kinder Morgan Energy Partners has obtained additional customer contracts, extended existing customer contracts and remarketed expiring contracted capacity at competitive rates. For the Gulf Coast and other liquids terminals, the existing contracts generally mature at various times and in varying amounts of throughput capacity, therefore, we continue to manage the recontracting process in order to limit the risk of significant impacts on Kinder Morgan Energy Partners' revenues. The increase in earnings in 2005 versus 2004 was also largely due to higher revenues, driven by higher sales of petroleum transmix, new customer agreements, and escalations in annual contract provisions;

- an increase of $9.4 million (29%) and a decrease of $3.3 million (10%), respectively, from the Mid-Atlantic region. The 2006 increase was driven by a $5.7 million increase from the Shipyard River terminal, located in Charleston, South Carolina; a $2.6 million increase from the Fairless Hills, Pennsylvania bulk terminal; and a $1.2 million increase from the North Charleston, South Carolina liquids terminal. The increase from Shipyard reflects higher revenues from liquids warehousing and coal and cement handling, the increase from Fairless Hills was due to higher volumes of steel imports and heavier shipping activity on the Delaware River, and the increase from North Charleston was due to higher revenues, associated with additional liquids tank leasing and a utilization capacity rate that approached 100% (full capacity).

  The decrease in earnings in 2005 compared to 2004 included a $2.1 million decrease in earnings from the Pier IX bulk terminal, located in Newport News, Virginia, and a $2.0 million decrease in earnings from the Chesapeake Bay facility, located in Sparrows Point, Maryland. The decrease from Pier IX was primarily due to higher operating expenses in 2005 compared to 2004, due to incremental operating expenses associated with a new synfuel maintenance program and higher demurrage expenses associated with increased cement imports. The decrease from the Chesapeake terminal was mainly due to higher operating expenses associated with higher movements of petroleum coke;

- an increase of $4.6 million (19%) and a decrease of $0.8 million, respectively, from terminals included in the Texas Petcoke region. The increase in 2006 compared to 2005 was primarily revenue driven, resulting from a year-over-year increase in petroleum coke handling volumes. The decrease in 2005 compared to 2004 was related to incremental overhead expenses allocated to the Texas Petcoke region, which was newly formed in April 2005;

- an increase of $4.5 million (16%) and a decrease of $7.2 million (21%), respectively, from terminals included in the Lower Mississippi River (Louisiana) region. The increase in 2006 compared to 2005 was primarily due to incremental earnings from the Amory and DeLisle Mississippi bulk terminals, and from higher earnings from the Kinder Morgan St. Gabriel, Louisiana terminal. The Amory terminal began operations in July 2005. The higher earnings from the DeLisle terminal, which was negatively impacted by hurricane damage in 2005, was primarily due to higher bulk transfer revenues in 2006. The increase from the St. Gabriel terminal was primarily due to a $1.8 million income item, recognized in 2006, related to a favorable settlement associated with the purchase of the terminal in September 2002.

  The overall decrease in earnings from the Louisiana region terminals in 2005 compared to 2004 was largely related to the negative effects of the two Gulf Coast hurricanes in 2005, resulting in an overall general loss of business. In addition to property damage incurred, throughput at the facilities impacted by the storms decreased in 2005 compared to 2004 largely due to post-hurricane production issues at a number of Gulf Coast refineries. In 2005, the Terminals – KMP segment realized essentially all of the losses related to both hurricanes, and in total, the segment recognized $2.6 million in expense in 2005 in order to meet its insurance deductible for Hurricane Katrina. Kinder Morgan Energy Partners also recognized another $0.8 million to repair damaged facilities following Hurricane Rita, but estimates of lost business at the terminal sites are difficult because of insurance complexities and the extended recovery time involved;

- an increase of $3.7 million (8%) and a decrease of $1.0 million (2%), respectively, from terminals included in the Northeast region. The increase in 2006 compared to 2005 was primarily due to higher earnings from the liquids terminals located in Carteret, New Jersey and Staten Island, New York. The increase was largely due to higher revenues from new and renegotiated customer contracts at Carteret, additional tankage available for lease at the Kinder Morgan Staten Island terminal, and an overall increase in petroleum imports to New York Harbor, resulting in an 8% increase in total liquids throughput at Carteret and higher distillate volumes at the Staten Island terminal.

  The decrease in 2005 compared to 2004 was driven by lower earnings from the dry-bulk services at the Port Newark, New Jersey facility. The decrease was largely due to lower salt tonnage, shipping activity, and stevedoring services, all primarily due to warmer winter weather in 2005; and

- increases of $2.2 million (4%) and $4.4 million (10%), respectively, from terminals in the Midwest region. The year-over-year increase in earnings in 2006 was mainly attributable to higher earnings from the combined operations of the Argo and Chicago, Illinois liquids terminals, and from the Cora, Illinois coal terminal. The increase from the liquids terminals was due to higher revenues from increased ethanol throughput and incremental liquids storage and handling business. The year-to-year increase in earnings at Cora was due to higher revenues resulting from an almost 24% increase in coal transfer volumes.

  The overall increase in 2005 compared to 2004 included higher earnings from the Dakota bulk terminal, located along the Mississippi River near St. Paul, Minnesota; the Argo, Illinois liquids terminal, situated along the Chicago sanitary and ship channel; and the Milwaukee, Wisconsin bulk commodity terminal. The increase in earnings from Dakota was primarily due to higher revenues generated by a cement unloading and storage facility, which began operations in late 2004. The increase from the Argo terminal was mainly due to new customer contracts and higher ethanol handling revenues. The increase from the Milwaukee bulk terminal was mainly due to an increase in coal handling revenues related to higher coal truckage within the State of Wisconsin.

Segment Details

Segment revenues from terminal operations owned during identical periods of both 2006 and 2005 increased $96.7 million (14%) in 2006, when compared to the prior year. The overall increase was primarily due to the following:

- a $24.1 million (29%) increase from the Mid-Atlantic region, due primarily to higher revenues of $11.7 million from Fairless Hills, $9.7 million from Shipyard River, and $1.6 million from the North Charleston terminals, all discussed above. Also, the Philadelphia, Pennsylvania liquids terminal reported a $2.5 million increase in revenues in 2006 versus 2005 largely due to an increase in fuel grade ethanol volumes, annual rate escalations on certain customer contracts, and a 2006 liquids capacity utilization rate of approximately 97%;

- a $19.6 million (19%) increase from the Gulf Coast liquids facilities, due primarily to higher revenues from Pasadena and Galena Park, as discussed above;

- a $19.1 million (43%) increase from the Texas Petcoke terminal region, due primarily to higher petroleum coke transfer volumes;

- a $13.4 million (92%) increase from engineering and terminal design services, due to both incremental revenues from new clients, additional project phase revenues, and increased revenues from material sales;

- a $5.5 million (5%) increase from terminals included in the Midwest region, due largely to the increased liquids throughput, storage and ethanol activities from the two Chicago liquids terminals and to the increased coal volumes from the Cora coal terminal, both described above. The overall increase in revenues was also due to higher marine oil fuel and asphalt sales from the Dravosburg, Pennsylvania bulk terminal;

- a $5.1 million (16%) increase from the Ferro alloys region, largely due to increased ores and metals handling at the Chicago and Industry, Pennsylvania terminals; and

- a $4.6 million (5%) increase from the Northeast terminals, largely due to the revenue increases at the Carteret and Kinder Morgan Staten Island terminals, as discussed above.

For all bulk terminal facilities combined, total transloaded bulk tonnage volumes increased over 4.5% in 2006, when compared to 2005. The overall increase in bulk tonnage volumes included a 10% increase in coal transfer volumes and a 13% increase in ores/metals transload volumes. Kinder Morgan Energy Partners also completed, in 2006, capital expansion and betterment projects at certain of its liquids terminal facilities that included the construction of additional petroleum products storage tanks. The construction, when combined with increases from external acquisitions, increased Kinder Morgan Energy Partners' liquids storage capacity by approximately 1.1 million barrels (2.6%) in 2006. At the same time, Kinder Morgan Energy Partners increased its liquids utilization capacity rate by 1%, compared to the prior year. The liquids terminals utilization rate is the ratio of actual leased capacity to estimated potential capacity. Potential capacity is generally derived from measures of total capacity, taking into account periodic changes to terminal facilities due to additions, disposals, obsolescence, or other factors.

Segment revenues for all terminals owned during identical periods of both 2005 and 2004 increased $43.6 million (8%) in 2005, when compared to the prior year. The increase was primarily due to the following:

- a $16.7 million (19%) increase from the Pasadena and Galena Park Gulf Coast liquids terminals, due primarily to higher petroleum transmix sales and to additional customer contracts and tankage capacity;

- a $12.3 million (14%) increase from the Midwest region, due primarily to higher cement handling revenues at the Dakota terminal, increased tonnage at the Milwaukee terminal, and higher marine fuel sales at the Dravosburg, Pennsylvania terminal;

- a $6.8 million (11%) increase from the Mid-Atlantic region, due primarily to higher coal volumes and higher dockage revenues at the Shipyard River terminal, higher cement, iron ore, and dockage revenues at the Pier IX bulk terminal, and incremental revenues from the North Charleston liquids/bulk terminal, located just north of the Shipyard facility and acquired effective April 30, 2004;

- a $4.0 million (38%) increase from engineering and terminal design services, due to increased fee revenues discussed above;

- a $3.9 million (9%) increase from the Southeast region, due primarily to both higher fertilizer and ammonia volumes and higher stevedoring services at terminal operations located in and around the Tampa, Florida area. These operations include the import and export business of the Kinder Morgan Tampaplex terminal, the commodity transfer operations of the Port Sutton terminal, and the terminal stevedoring services Kinder Morgan Energy Partners performs along Tampa Bay; and

- a $2.8 million (3%) decrease from terminals included in the Louisiana region. The decrease was largely due to the negative impact and business interruptions resulting from the two hurricanes that struck the Gulf Coast in the second half of 2005.

Operating expenses from all terminals owned during identical periods of both 2006 and 2005 increased $38.1 million (10%) in 2006 compared to 2005. Combined, the net effect of the environmental liability adjustments, hurricane repair expenses, and the property casualty gain on terminals owned during the same portions of both comparable periods resulted in a $15.9 million decrease in segment operating expenses in 2006 relative to 2005. The remaining change in year-to-year operating expenses—an increase of $54.0 million (15%)—from all terminals owned during identical periods of both 2006 and 2005 primarily consisted of the following:

- a $15.3 million (111%) increase from engineering-related services, due primarily to higher salary, overtime and other employee-related expenses related to new hiring, as well as increased contract labor, all associated with the increased project work described above;

- a $15.0 million (75%) increase from the Texas Petcoke terminal region, due largely to higher labor expenses, rail service and railcar maintenance expenses, and harbor and barge expenses, all related to higher petroleum coke volumes;

- a $14.1 million (28%) increase from the Mid-Atlantic terminals, largely due to higher operating and maintenance expenses at the Fairless Hills, Shipyard River, and Philadelphia terminals. The increase at Fairless Hills was largely due to higher wharfage, trucking and general maintenance expenses related to the increase in steel products handled. The increase at Shipyard was due to higher labor, equipment rentals, and general maintenance expenses, all associated with increased tonnage. The increase at the Philadelphia liquids terminal was due to higher expenses related to certain environmental liability accruals;

- a $4.0 million (21%) increase from terminals in the Ferro alloys region, due primarily to higher labor expenses and higher equipment maintenance and rental expenses, all related to increased ores and metals handling volumes; and

- a $3.7 million (6%) increase from the Midwest region terminals, due primarily to higher marine fuel costs of sales expenses at the Dravosburg terminal; higher maintenance and outside service expenses associated with increases in coal transfer volumes at the Cora, Illinois and Grand Rivers, Kentucky coal terminals; and additional labor and equipment rental expenses from the combined operations of the Argo and Chicago, Illinois liquids terminals, due to increased ethanol throughput and incremental liquids storage and handling business.

For terminal operations owned during the same months of both 2005 and 2004, operating expenses increased $54.3 million (21%) in 2005 compared to 2004. The overall increase included a $22.2 million increase in expense attributable to the 2005 and 2004 environmental liability adjustments. The remaining $32.2 million (12%) increase in operating expenses in 2005 versus 2004 from terminal operations owned during both years primarily consisted of the following:

- a $10.1 million (36%) increase from the Mid-Atlantic terminals, largely due to higher operating, maintenance and labor expenses at the Pier IX and Chesapeake Bay facilities, discussed above, and to higher operating, equipment maintenance and labor expenses at the Shipyard River terminal, due to higher bulk tonnage volumes;

- an $8.5 million (18%) increase from the Midwest region terminals, due primarily to higher expenses at the Milwaukee, Dravosburg and Dakota bulk handling terminals. The increase at the Milwaukee bulk commodity terminal was due to increased trucking and maintenance expenses associated with the increase in coal volumes. The increase at Dravosburg was largely due to higher cost of sales expenses, due to marine oil purchasing costs and inventory maintenance, and the increase at the St. Paul, Minnesota Dakota bulk terminal was due to both higher repair and labor expenses, associated with higher cement volumes, and lower capitalized overhead in 2005, due to the completion of its cement unloading and storage facility in late 2004;

- a $3.1 million (5%) increase from the Louisiana terminals, largely due to property damage, demurrage and other expenses, which in large part related to the effects of hurricanes Katrina and Rita in the last half of 2005. However, since the affected properties were insured, expenses were limited to the amount of the deductible under insurance policies;

- a $2.9 million (12%) increase from the Pasadena and Galena Park Gulf Coast liquids terminals, due chiefly to higher labor, and higher fuel and power expenses associated with increased terminal activities; and

- a $2.6 million (21%) increase from terminals in the West region, due mainly to higher labor expenses and port fees resulting from increased tonnage at terminal facilities located at Longview and Vancouver, Washington. Both facilities provide ship loading services along the Columbia River.

The segment's earnings from equity investments remained flat across both 2006 and 2005, when compared to prior years. Income from other items was essentially unchanged in 2005 versus 2004, but increased $2.3 million in 2006 compared to 2005. The increase included a $1.8 million income item, recognized in 2006, related to a favorable settlement associated with the purchase of the Kinder Morgan St. Gabriel terminal in September 2002, and a $1.2 million increase related to a disposal loss, recognized in 2005, on warehouse property at the Elizabeth River bulk terminal, located in Chesapeake, Virginia.

Income tax expenses totaled $12.2 million in 2006, $11.1 million in 2005 and $5.6 million in 2004. The $1.1 million (10%) increase in 2006 versus 2005 reflects, among other things, incremental income tax expense associated with hurricane related income and expense items. The $5.5 million (98%) increase in 2005 compared to 2004 was mainly attributable to the year-to-year changes in both taxable income and certain permanent differences between taxable income and financial income of Kinder Morgan Bulk Terminals, Inc. and its consolidated subsidiaries. Kinder Morgan Bulk Terminals, Inc. is the tax-paying entity that owns many of Kinder Morgan Energy Partners' bulk terminal businesses which handle non-qualifying products. In general, the segment's income tax expenses will change period to period based on the classification of income before taxes between amounts earned by corporate subsidiaries and amounts earned by partnership subsidiaries.

Non-cash depreciation, depletion and amortization charges increased $15.5 million (26%) in 2006 compared to 2005 and $16.2 million (38%) in 2005 compared to 2004. The year-over-year increases in depreciation expenses reflect a rising depreciable capital base since the end of 2004, with growth due to a combination of business acquisitions and internal capital spending. Collectively, the terminal assets acquired since the beginning of 2005 and listed above accounted for incremental depreciation expenses of $8.2 million in 2006, and the assets acquired since the third quarter of 2004 and listed above accounted for incremental depreciation expenses of $12.4 million in 2005. The remaining increases in year-to-year depreciation expenses were associated with capital spending on numerous improvement projects completed since 2004 in order to expand and enhance terminal services.

TransColorado

	Year Ended December 31, 2004
	(In millions)
Operating Revenues	$ 28.8
Gas Purchases and Other Costs of Sales	$ 0.8
Segment Earnings	$ 20.3

Effective November 1, 2004, we contributed TransColorado Gas Transmission Company to Kinder Morgan Energy Partners (see Note 5 of the accompanying Notes to Consolidated Financial Statements). TransColorado's results shown above reflect its earnings through October 31, 2004 and nothing thereafter, however, we will continue to participate in the results of operations of TransColorado through our equity investment in Kinder Morgan Energy Partners. We recognized a $0.6 million pre-tax loss from the contribution of TransColorado, which is included in segment earnings, as reported above. TransColorado's segment earnings decreased from $23.1 million in 2003 to $20.3 million in 2004, principally due to the fact that 2004 results include only the ten months through October 2004 and also include the $0.6 million pre-tax loss from the contribution of TransColorado.

Earnings from Our Investment in Kinder Morgan Energy Partners

The impact on our pre-tax earnings from our investment in Kinder Morgan Energy Partners during 2005 and 2004, when we accounted for Kinder Morgan Energy Partners under the equity method, was as follows:

	Year Ended December 31,	
	2005	2004
	(In millions)	
General Partner Interest, Including Minority Interest in the Operating Limited Partnerships	$ 484.6	$ 403.5
Limited Partner Units (Kinder Morgan Energy Partners)	32.3	41.1
Limited Partner i-units (Kinder Morgan Management)	88.5	113.5
	605.4	558.1
Pre-tax Minority Interest in Kinder Morgan Management	(70.6)	(81.1)
Pre-tax Earnings from Investment in Kinder Morgan Energy Partners[1]	$ 534.8	$ 477.0

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[1] Pre-tax earnings from our investment in Kinder Morgan Energy Partners in 2005, when we accounted for Kinder Morgan Energy Partners under the equity method, was negatively impacted by approximately $32.6 million due principally to the effects of certain regulatory, environmental, litigation and inventory items on Kinder Morgan Energy Partners' 2005 earnings.

As discussed in Note 1(B) of the accompanying Notes to Consolidated Financial Statements, due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts, balances and results of operations of Kinder Morgan Energy Partners are included in our consolidated financial statements and we no longer apply the equity method of accounting to our investment in Kinder Morgan Energy Partners. The inclusion of Kinder Morgan Energy Partners as a consolidated subsidiary affects the reported amounts of our consolidated revenues and expenses and our reported segment earnings. However, after taking into account the associated minority interests, the adoption of EITF No. 04-5 has no impact on our income from continuing operations or our net income. The net impact on pre-tax earnings of our investment in Kinder Morgan Energy Partners was $582.9 million for the year ended 2006.

Our pre-tax earnings from Kinder Morgan Energy Partners were positively impacted in 2006, in part, by the positive impacts of internal growth and acquisitions on Kinder Morgan Energy Partners' earnings and cash flows. Additional information on Kinder Morgan Energy Partners is contained in its Annual Report on Form 10-K for the year ended December 31, 2006.

Interest and Corporate Expenses, Net

	Year Ended December 31,		
	2006	**2005**	**2004**
		(In millions)	
General and Administrative Expense	$ (369.3)	$ (72.3)	$ (67.7)
Interest Expense, Net	(765.3)	(166.3)	(125.3)
Interest Expense – Deferrable Interest Debentures	(21.9)	(21.9)	(21.9)
Interest Expense – Capital Securities	(8.7)	(0.7)	–
Minority Interests	(374.2)	(50.4)	(56.4)
Loss on Mark-to-market Interest Rate Swaps	(22.3)	–	–
Gain on Sale of Kinder Morgan Management Shares	–	78.5	–
Contribution to Kinder Morgan Foundation	–	(15.0)	–
Loss on Early Extinguishment of Debt	–	–	(3.9)
Other, Net	21.5	12.0	(28.4)
	$ (1,540.2)	$ (236.1)	$ (246.8)

"Interest and Corporate Expenses, Net" was an expense of $1,540.2 million for the year ended December 31, 2006, compared to an expense of $236.1 million for the year ended December 31, 2005. The increase in net expenses was principally due to (i) the inclusion of the accounts, balances and results of operations of Kinder Morgan Energy Partners in our consolidated financial statements due to our adoption of EITF No. 04-5 (see Note 1(B) of the accompanying Notes to Consolidated Financial Statements) and (ii) the acquisition of Terasen on November 30, 2005 (see Note 4 of the accompanying Notes to Consolidated Financial Statements).

"Interest and Corporate Expenses, Net" was an expense of $236.1 million for the year ended December 31, 2005, compared to an expense of $246.8 million for the year ended December 31, 2004. The decrease was principally due to a pre-tax gain of $78.5 million from the sale of Kinder Morgan Management shares in 2005, as discussed below, offset by (i) a $15.0 million contribution to the Kinder Morgan Foundation and (ii) higher total interest and general and administrative costs in 2005, as discussed below.

The $297.0 million increase in general and administrative expense in 2006, relative to 2005, was due to (i) $219.6 million of general and administrative expense of Kinder Morgan Energy Partners being included in our consolidated financial statements due to our adoption of EITF No. 04-5, (ii) $85.7 million of general and administrative expense of Terasen, partially offset by a $8.3 million decrease in other general and administrative expenses.

The $4.6 million increase in general and administrative expense in 2005, relative to 2004, was principally due to the general and administrative costs of Terasen.

The $607.0 million increase in total interest expense in 2006, relative to 2005, was due to (i) $332.0 million of interest expense of Kinder Morgan Energy Partners being included in our consolidated financial statements due to our adoption of EITF No. 04-5, (ii) $258.3 million of interest expense resulting from (1) interest on Terasen's existing debt, including debt issued in 2006 and (2) interest on incremental debt issued during the fourth quarter of 2005 to acquire Terasen and (iii) a $16.7 million increase in other interest expense resulting from higher effective interest rates, partially offset by lower debt balances.

The $41.7 million increase in total interest expense in 2005, relative to 2004, was due to (i) higher effective rates, partially offset by lower outstanding balances on our pre-Terasen debt and (ii) approximately $22.3 million of interest due to interest on Terasen's existing debt and on incremental debt issued to acquire Terasen (see Notes 4 and 10 of the accompanying Notes to Consolidated Financial Statements).

The $323.8 million increase in minority interests in 2006, relative to 2005, was due to (i) $300.8 million of minority interests of Kinder Morgan Energy Partners being included in our consolidated financial statements due to our adoption of EITF No.

04-5, (ii) a $21.0 million increase in minority interests of Kinder Morgan Management and (iii) a $2.0 million increase in other minority interests, principally Triton Power.

The $6.0 million decrease in minority interests in 2005, relative to 2004, was due principally to (i) a $5.4 million decrease in minority interests of Kinder Morgan Management and (ii) a $0.6 million decrease in minority interests of Triton Power.

During the first quarter of 2006, we recorded a pre-tax charge of $22.3 million ($14.1 million after tax) related to the financing of the Terasen acquisition. The charge was necessary because certain hedges put in place related to the debt financing for the acquisition did not qualify for hedge treatment under Generally Accepted Accounting Principles, thus requiring that they be marked-to-market, resulting in a non-cash charge to income. These hedges have now been effectively terminated and replaced with agreements that qualify for hedge accounting treatment (see Note 12 of the accompanying Notes to Consolidated Financial Statements).

During 2005, we sold a total of 5.7 million Kinder Morgan Management shares that we owned, receiving net proceeds of $254.8 million. In conjunction with these sales, we recorded pre-tax gains of $78.5 million (see Note 5 of the accompanying Notes to Consolidated Financial Statements).

Income Taxes – Continuing Operations

The income tax provision decreased from $345.5 million in 2005 to $274.1 million in 2006, a decrease of $71.4 million (21%) due principally to (i) a decrease of $198.9 million due to a decrease in pre-tax income from continuing operations of $552.6 million, (ii) an increase of $227.7 million related to the impairment of nondeductible goodwill, (iii) a reduction of $45.1 million resulting from a favorable financing structure utilized in the Terasen acquisition, (iv) a reduction of $38.0 million due to the impact of applying a lower effective tax rate on previously recorded net deferred tax liabilities, (v) a decrease of $19.5 million due to foreign earnings subject to different tax rates, (vi) an increase of $12.7 million attributable to the net tax effects of Kinder Morgan Energy Partners, L.P.'s corporate equity earnings, (vii) an increase of $7.5 million related to Kinder Morgan Management minority interest and (viii) a decrease of $17.8 million attributable to other items.

The income tax provision increased from $208.0 million in 2004 to $345.5 million in 2005, an increase of $137.5 million (66%) due principally to (i) the fact that the 2004 tax provision includes a reduction of $69.4 million due to the impact of applying a lower effective tax rate on previously recorded net deferred tax liabilities, (ii) an increase of $64.6 million due to an increase in pre-tax income from continuing operations of $169.2 million, (iii) a decrease of $2.0 million related to Kinder Morgan Management minority interest and (iv) an increase of $5.5 million attributable to other items.

See Note 9 of the accompanying Notes to Consolidated Financial Statements for additional information on income taxes.

Income Taxes – Realization of Deferred Tax Assets

A capital loss carryforward can be utilized to reduce capital gain during the five years succeeding the year in which a capital loss is incurred. At December 31, 2004, we had a capital loss carryforward of approximately $56.1 million, of which $52.5 million was to expire in 2005. In addition, during the third quarter of 2005, the Wrightsville power facility (in which we owned an interest) was sold to Arkansas Electric Cooperative Corporation, generating an estimated capital loss for tax purposes of $64.6 million. We did not record a loss for book purposes due to the fact that we had previously written off the carrying value of our investment in the Wrightsville power facility.

During 2005, in order to offset our capital loss carrryforward expiring in 2005 and our capital loss from the Wrightsville power facility, we sold 5.67 million Kinder Morgan Management shares that we owned, generating a gain for tax purposes of $118.1 million.

As a result of these and other transactions, at December 31, 2006, our capital loss carryforward is approximately $2.4 million which expires $1.6 million during 2008 and $0.8 million during 2009. No valuation allowance has been provided with respect to this deferred tax asset.

Discontinued Operations

In August 2006, we entered into a definitive agreement with a subsidiary of General Electric Company to sell our U.S. retail natural gas distribution and related operations for $710 million plus working capital. Pending regulatory approvals, we expect this transaction to close by the end of the first quarter of 2007. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* the financial results of these operations have been reclassified to discontinued operations for all periods presented. For the twelve months ended December 31, 2006, 2005 and 2004, we recorded $24.5 million of income (net of tax of $10.3 million), $22.2 million of income (net of tax of $15.4 million) and $30.3 million of income (net of tax of $18.7 million), respectively, from these operations.

On November 30, 2005, we acquired Terasen (see Note 4 of the accompanying Notes to Consolidated Financial Statements). At that time, we adopted and implemented a plan to discontinue the water and utility services line of business operated by Terasen, which offers water, wastewater and utility services, primarily in Western Canada. In December of 2005, we recorded losses of $0.7 million (net of tax benefits of $0.3 million) to reflect the one month operating results of the water and utility business segment since its inclusion in our Consolidated Statement of Operations. During the second quarter of 2006, our wholly owned subsidiary, Terasen Inc., completed the sale of Terasen Water and Utility Services to a group led by CAI Capital Management Co. and including the existing management team of Terasen Water and Utility Services for approximately $118 million (C$133 million). The sale does not include CustomerWorks LP, a 30% joint venture with Enbridge Inc. No gain or loss was recognized from the sale of the water and utility segment. Incremental losses of $0.7 million (net of tax benefits of $0.4 million) were recorded in the six months ended June 30, 2006 reflecting the operating results of the water and utility business segment during 2006 until its sale.

During 1999, we adopted and implemented a plan to discontinue a number of lines of business. During 2000, we essentially completed the disposition of these discontinued operations. During 2006, incremental losses of approximately $0.6 million (net of tax benefits of $0.3 million) were recorded to increase previously recorded liabilities to reflect updated estimates. During 2005, a gain of $3.2 million (net of tax of $1.9 million) was recorded to reflect the settlement of previously recorded liabilities. During 2004, incremental losses of approximately $6.4 million (net of tax benefits of $3.8 million) were recorded to increase previously recorded liabilities to reflect updated estimates.

Note 7 of the accompanying Notes to Consolidated Financial Statements contains additional information on these matters.

Liquidity and Capital Resources

Primary Cash Requirements

Our primary cash requirements, in addition to normal operating, general and administrative expenses, are for debt service, capital expenditures, common stock repurchases, quarterly cash dividends to our common shareholders and quarterly distributions to Kinder Morgan Energy Partners' public common unitholders. Our capital expenditures (other than sustaining capital expenditures), our common stock repurchases and our quarterly cash dividends to our common shareholders are discretionary. Our capital expenditures for 2007 are currently expected to be approximately $2.5 billion, of which $6.3 million is associated with assets held for sale. Depending on the timing of when our proposed sales of assets take place during 2007, our total capital expenditures may be reduced from the 2007 budget amount. We expect to fund these expenditures with existing cash, cash flows from operating activities. In addition to utilizing cash generated from operations, we could meet these cash requirements through borrowings under our $800 million credit facility. In addition, Kinder Morgan Energy Partners and Terasen could meet their respective cash requirements with cash from operations and through borrowings under their respective credit facilities or by issuing short-term commercial paper or bankers' acceptances or long-term notes. Furthermore, Kinder Morgan Energy Partners could issue additional units.

On August 28, 2006, we entered into a definitive merger agreement under which investors led by Richard D. Kinder, our Chairman and Chief Executive Officer, will acquire all of our outstanding common stock for $107.50 per share in cash (the "Going Private" transaction). The Going Private agreement has been approved by our board of directors and stockholders and the transaction is anticipated to close in the first or second quarter of 2007, subject to receipt of regulatory approvals and the satisfaction of other customary closing conditions. The total amount of funds estimated to be necessary to complete the proposed merger and related transactions, including debt to be incurred and to remain outstanding in connection with the merger, and to pay related customary fees and expenses, is approximately $22.4 billion, consisting of (i) up to $5.0 billion in new equity financing from private equity funds and other entities providing equity financing, (ii) approximately $2.9 billion from rollover investors, who are certain current or former directors, officers or other members of management of Kinder Morgan, Inc. (or entities controlled by such persons) that are directly or indirectly reinvesting all or a portion of their equity interests in Kinder Morgan, Inc. and/or cash in exchange for equity interests in Knight Holdco LLC, the parent of the surviving entity of the merger, (iii) approximately $7.3 billion in new debt financing to be issued pursuant to a debt commitment letter dated July 18, 2006 and expiring on September 30, 2007, in which a syndicate of banks have each severally and not jointly committed to provide (each committing 20%) to Kinder Morgan, Inc. up to $8.6 billion of senior secured facilities, subject to a number of conditions as set forth in the commitment letter and (iv) approximately $7.2 billion of our existing indebtedness expected to remain outstanding in connection with the merger. Prior to the effective time of the merger, Knight Holdco LLC may permit additional rollover commitments from other members of senior management, in which case, the aggregate new equity commitments will decrease by the aggregate amount of rollover commitments.

Invested Capital

Our net debt to total capital increased significantly in the first quarter of 2006 due to our adoption of EITF No. 04-5, which resulted in the inclusion of the accounts, balances and results of operations of Kinder Morgan Energy Partners in our consolidated financial statements beginning January 1, 2006. Although the total debt on our consolidated balance sheet increased as a result of including Kinder Morgan Energy Partners' debt balances with ours, Kinder Morgan, Inc. has not assumed any additional obligations with respect to Kinder Morgan Energy Partners' debt. See Note 1(B) of the accompanying Notes to Consolidated Financial Statements for information regarding EITF No. 04-5. Our ratio of net debt to total capital increased in the fourth quarter of 2005 as a result of the acquisition of Terasen. In recent periods, we have significantly increased our dividends per common share. We expect our ratio of net debt to total capital to increase further in the first or second quarter of 2007 with the anticipated increase in debt if the proposed merger agreement, as discussed previously, is consummated.

In addition to the direct sources of debt and equity financing shown in the following table, we obtain financing indirectly through our ownership interests in unconsolidated entities as shown under "Significant Financing Transactions" following. In addition to our results of operations, these balances are affected by our financing activities as discussed following.

	December 31,		
	2006	2005	2004
		(Dollars in millions)	
Long-term Debt:			
Outstanding Notes and Debentures	$ 10,623.9	$ 6,286.8	$ 2,258.0
Deferrable Interest Debentures Issued to Subsidiary Trusts	283.6	283.6	283.6
Capital Securities	106.9	107.2	-
Value of Interest Rate Swaps[1]	46.4	51.8	88.2
	11,060.8	6,729.4	2,629.8
Minority Interests	3,095.5	1,247.3	1,105.4
Common Equity, Excluding Accumulated Other Comprehensive Loss	3,657.5	4,051.4	2,919.5
	17,813.8	12,028.1	6,654.7
Less Value of Interest Rate Swaps	(46.4)	(51.8)	(88.2)
Capitalization	17,767.4	11,976.3	6,566.5
Short-term Debt, Less Cash and Cash Equivalents[2]	2,046.7	841.4	328.5
Invested Capital	$ 19,814.1	$ 12,817.7	$ 6,895.0
Capitalization:			
Outstanding Notes and Debentures	59.8%	52.5%	34.4%
Minority Interests	17.4%	10.4%	16.8%
Common Equity	20.6%	33.8%	44.5%
Deferrable Interest Debentures Issued to Subsidiary Trusts	1.6%	2.4%	4.3%
Capital Securities	0.6%	0.9%	-%
Invested Capital:			
Net Debt[3, 4]	63.9%	55.6%	37.5%
Common Equity, Excluding Accumulated Other Comprehensive Loss and Including Deferrable Interest Debentures Issued to Subsidiary Trusts, Capital Securities and Minority Interests	36.1%	44.4%	62.5%

[1] See "Interest Rate Swaps" following.

[2] Cash and cash equivalents netted against short-term debt were $129.8, $116.6 and $176.5 for December 31, 2006, 2005 and 2004, respectively.

[3] Outstanding notes and debentures plus short-term debt, less cash and cash equivalents.

[4] Our ratio of net debt to invested capital at December 31, 2006, not including the effects of consolidating Kinder Morgan Energy Partners, was 55.9%.

Except for our Terasen subsidiaries and Kinder Morgan Energy Partners and its subsidiaries, we employ a centralized cash management program that essentially concentrates the cash assets of our subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing. Our centralized cash management program provides that funds in excess of the daily needs of our subsidiaries be concentrated, consolidated, or otherwise made available for use by other entities within our consolidated group. We place no restrictions on the ability to move cash between entities, payment of intercompany balances or the ability to upstream dividends to parent companies other than restrictions that may be contained in agreements governing the indebtedness of those entities; provided that neither we nor our subsidiaries (other than Kinder Morgan Energy Partners and its subsidiaries) have rights with respect to the cash of Kinder Morgan Energy Partners or its subsidiaries except as permitted by Kinder Morgan Energy Partners' partnership agreement.

In addition, certain of our operating subsidiaries are subject to FERC-enacted reporting requirements for oil and natural gas pipeline companies that participate in cash management programs. FERC-regulated entities subject to these rules must, among other things, place their cash management agreements in writing, maintain current copies of the documents authorizing and supporting their cash management agreements, and file documentation establishing the cash management program with the FERC.

Terasen, for certain of its subsidiaries, employs a centralized cash management program that essentially concentrates the cash assets of these subsidiaries for the purpose of providing financial flexibility and lowering the cost of borrowing. Terasen's centralized cash management program provides that funds in excess of the daily needs of its subsidiaries be concentrated or consolidated for use by other entities within the Terasen group.

Terasen Gas Inc. and TGVI, as stand-alone regulated entities, each operate their own separate cash management programs, funding short-term capital requirements through either commercial paper issuance or drawing on available credit facilities, while investing funds in excess of daily needs on a short-term basis to lower the overall net cost of borrowing.

As part of the conditions attached to the approval of the Terasen acquisition by the BCUC, the Terasen-owned utilities regulated by the BCUC, including Terasen Gas Inc. and TGVI, are required to maintain a percentage of common equity to total capital that is at least as much as that determined by the BCUC from time to time for ratemaking purposes, and none may pay a dividend that would reasonably be expected to violate this restriction without prior BCUC approval.

Short-term Liquidity

Our principal sources of short-term liquidity are our revolving bank facilities, commercial paper programs of Kinder Morgan Energy Partners and commercial paper and bankers' acceptances programs of Terasen (which are supported by their respective revolving bank facilities) and cash provided by operations. The following represents the revolving, unsecured credit facilities that were available to Kinder Morgan, Inc. and its respective subsidiaries, amounts outstanding and available borrowing capacity under the facilities after applicable letters of credit.

	At December 31, 2006		At January 31, 2007	
	Short-term Debt Outstanding	Available Borrowing Capacity	Short-term Debt Outstanding	Available Borrowing Capacity
	(In millions of U.S. dollars)			
Kinder Morgan, Inc.				
$800 million, five-year revolver, due August 2010[1]	$ 90.0	$ 640.1	$ 155.0	$ 575.1
Kinder Morgan Energy Partners				
$1.85 billion, five-year revolver, due August 2010[2]	1,098.2	366.1	225.0	1,201.8
Terasen				
C$450 million, three-year revolver, due May 2009	97.8	224.6	101.1	217.3
Terasen Gas Inc.				
C$500 million, three-year revolver, due June 2009	186.2	205.5	158.9	229.0
Terasen Pipelines (Corridor) Inc.				
C$225 million, 364-day revolver, due January 2007	193.1	-	191.2	-

[1] On January 5, 2007, after shareholder approval of the Going Private transaction was announced, Kinder Morgan, Inc.'s debt rating was downgraded by Standard & Poor's Rating Services to BB- with the anticipated increase in debt that would result if the transaction is consummated. This factor combined with the uncertainty that the Going Private transaction or any other proposals or extraordinary transaction will be approved or completed has limited our access to the commercial paper market. As a result, we are currently utilizing our $800 million credit facility for Kinder Morgan, Inc.'s short-term borrowing needs.

[2] On January 5, 2007, after shareholder approval of the Going Private transaction was announced, Kinder Morgan Energy Partners' credit rating was downgraded to BBB by Standard & Poor's Rating Services due to the anticipated increase in Kinder Morgan, Inc.'s debt that would result if the transaction is consummated.

These facilities can be used for the respective entity's general corporate purposes and as backup for that entity's respective commercial paper and bankers' acceptance programs. Additionally, at December 31, 2006 and January 31, 2007, we had a C$20 million demand facility associated with Terasen Pipelines (Corridor) Inc.'s credit facility put in place for overdraft purposes and short-term cash management. At December 31, 2006, $0.2 million was outstanding under the C$20 million demand facility at a weighted-average interest rate of 6.00%.

These bank facilities include financial covenants and events of default that are common in such arrangements. The terms of these credit facilities are discussed in Note 10 of the accompanying Notes to Consolidated Financial Statements.

Our current maturities of long-term debt of $511.2 million at December 31, 2006 represents (i) $5.0 million of current maturities of our 6.50% Series Debentures due September 1, 2013 (which are payable September 1, 2007), (ii) $250.0 million of Kinder Morgan Energy Partners' 5.35 % Senior Notes due August 15, 2007, (iii) $5.9 million of current maturities under Kinder Morgan Texas Pipeline, L.P.'s 5.23% Series Notes due January 2, 2014, (iv) $5.0 million of current maturities under Central Florida Pipe Line LLC's 7.84% Series Notes due July 23, 2007, (v) $1.2 million of current maturities under Terasen Gas Inc.'s capital lease obligations, (vi) $85.8 million of Terasen Gas Inc.'s 6.50% Series 13 Notes due October 16, 2007, (vii) $128.7 million of Terasen Gas Inc.'s Floating Rate Series 20 Medium Term Notes due June 2, 2007, (vii) $26.4 million of estimated current maturities relating to TGVI's C$350 million credit facility which, as discussed following, has been classified as long-term in our Consolidated Balance Sheet at December 31, 2006 and $3.2 million of current maturities of TGVI's government loans. Current maturities of Terasen and its subsidiaries are denominated in Canadian dollars but are reported here in U.S. dollars converted at the December 31, 2006 Bank of Canada closing rate of 0.8581 U.S. dollars per Canadian dollar. Apart from our notes payable and current maturities of long-term debt, our current liabilities, net of our current assets, represents an additional short-term obligation of $420.1 million at December 31, 2006. Given our expected cash flows from operations, our unused debt capacity as discussed preceding, including our credit facilities, our proceeds from the sale of assets and based on our projected cash needs in the near term, we do not expect any liquidity issues to arise.

Significant Financing Transactions

On January 23, 2007, Terasen Pipelines (Corridor) Inc. increased its credit facility from C$225 million to C$375 million and extended this facility and the associated C$20 million demand facility, as permitted under these facilities, for an additional 364 days.

On January 30, 2007, Kinder Morgan Energy Partners completed a public offering of senior notes. Kinder Morgan Energy Partners issued a total of $1.0 billion in principal amount of senior notes, consisting of $600 million of 6.00% notes due February 1, 2017 and $400 million of 6.50% notes due February 1, 2037. Kinder Morgan Energy Partners received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $992.8 million, and used the proceeds to reduce the borrowings under its commercial paper program.

On September 25, 2006, Terasen Gas Inc. issued C$120 million of 5.55% medium term note debentures, due September 25, 2036. Of the $106.9 million (C$119.4 million) net proceeds from this issuance after underwriting discounts and commissions, $89.5 million (C$100 million) was used to repay short-term commercial paper debt that was primarily incurred to pay Terasen Gas Inc.'s C$100 million 6.15% medium term note debentures that matured on July 31, 2006. The remaining proceeds were used to repay Terasen Gas Inc.'s C$20 million 9.75% notes, which matured on December 17, 2006.

Effective August 28, 2006, Kinder Morgan Energy Partners terminated its $250 million unsecured nine-month bank credit facility due November 21, 2006, and increased its existing five-year bank credit facility from $1.60 billion to $1.85 billion. The five-year unsecured bank credit facility remains due August 18, 2010; however, the bank facility can now be amended to allow for borrowings up to $2.1 billion. There were no borrowings under Kinder Morgan Energy Partners' five-year credit facility as of December 31, 2006.

In August 2006, Kinder Morgan Energy Partners issued, in a public offering, 5,750,000 common units, including common units sold pursuant to an underwriters' over-allotment option, at a price of $44.80 per unit, less commissions and underwriting expenses. Kinder Morgan Energy Partners received net proceeds of approximately $248.0 million for the issuance of these 5,750,000 common units.

In July 2006, we received notification of election from the holders of our 7.35% Series debentures due 2026 electing the option, as provided in the indenture governing the debentures, to require us to redeem the securities on August 1, 2006. The full $125 million of principal was elected to be redeemed and was paid, along with accrued interest of approximately $4.6 million, on August 1, 2006, utilizing incremental borrowing under our $800 million credit facility.

On July 31, 2006, Terasen Gas Inc.'s C$100 million 6.15% medium term note debentures matured, and the note holders were paid utilizing a combination of cash on hand and incremental short-term borrowing.

On June 30, 2006, TGVI made a $5.6 million (C$6.2 million) payment on its government loans, of which approximately $3.3 million (C$3.7 million) was refinanced through borrowings under its C$20 million non-revolving credit facility and the remaining amount funded with cash on hand. Additional information on the government loans can be found in Note 15(D) of the Notes to Consolidated Financial Statements included elsewhere in this report.

On June 21, 2006, Terasen Gas Inc. entered into a C$500 million three-year revolving credit facility, extendible annually for an additional 364 days at the option of the lenders. This facility replaces five bi-lateral facilities aggregating C$500 million and includes terms and conditions similar to the facilities it replaced.

On May 9, 2006, Terasen Inc. entered into a C$450 million three-year revolving credit facility. This facility replaces three bi-lateral facilities aggregating C$450 million and includes terms and conditions similar to the facilities it replaced.

On May 8, 2006, Terasen Inc.'s C$100 million of 4.85%, Series 2 Medium Term Notes matured and Terasen Inc. paid the holders of the notes, utilizing a combination of incremental short-term borrowing and proceeds from the sale of Terasen Water and Utility Services as previously discussed under "Discontinued Operations."

On April 28, 2006, Rockies Express Pipeline LLC entered into a $2.0 billion five-year, unsecured revolving credit facility due April 28, 2011. This credit facility supports a $2.0 billion commercial paper program that was established in May 2006, and borrowings under the commercial paper program reduce the borrowings allowed under the credit facility. Borrowings under the Rockies Express credit facility and commercial paper program will be primarily used to finance the construction of the Rockies Express interstate natural gas pipeline and to pay related expenses, and the borrowings will not reduce the borrowings allowed under our credit facilities described above.

Effective June 30, 2006, West2East Pipeline LLC (and its subsidiary Rockies Express Pipeline, LLC) was deconsolidated and will subsequently be accounted for under the equity method of accounting (See Note 5). All three owners have agreed to guarantee borrowings under the Rockies Express credit facility and under the Rockies Express commercial paper program in the same proportion as their percentage ownership of the member interests in Rockies Express Pipeline LLC. The three member owners and their respective ownership interests consist of the following: Kinder Morgan Energy Partners' subsidiary Kinder Morgan W2E Pipeline LLC – 51%, Sempra Energy – 25%, and ConocoPhillips – 24%. As of December 31, 2006, Rockies Express Pipeline LLC had $790.1 million of commercial paper outstanding, and there were no borrowings under its five-year credit facility. Accordingly, as of December 31, 2006, Kinder Morgan Energy Partners' contingent share of Rockies Express' debt was $403.0 million.

On February 22, 2006, Kinder Morgan Energy Partners entered into a nine-month $250 million credit facility due November 21, 2006 with a syndicate of financial institutions, and Wachovia Bank, National Association is the administrative agent. Borrowings under the credit facility can be used for general corporate purposes and as backup for Kinder Morgan Energy Partners' commercial paper program and include financial covenants and events of default that are common in such arrangements. This agreement was terminated concurrent with Kinder Morgan Energy Partners' increase of its 5-year credit facility from $1.6 billion to $1.85 billion.

On January 31, 2006, Terasen Pipelines (Corridor) Inc.'s $225 million senior unsecured revolving credit facility and the associated C$20 million non-revolving demand facility were extended under the same terms for an additional 364 days as permitted under the terms of the facilities.

On January 13, 2006, TGVI entered into a five-year C$350 million unsecured committed revolving credit facility with a syndicate of banks. TGVI issued bankers' acceptances under this facility to completely refinance TGVI's former term facility and intercompany advances from Terasen. The bankers' acceptances have terms not to exceed 180 days at the end of which time they are replaced by new bankers' acceptances. The facility can also be utilized to finance working capital requirements and for general corporate purposes. The terms and conditions are similar to those of the previous facility and common for such term credit facilities. Concurrently with executing this facility, TGVI entered into a C$20 million seven-year unsecured committed non-revolving credit facility with one bank. This facility will be utilized for purposes of refinancing any annual prepayments that TGVI may be required to make on non-interest bearing government contributions. The terms and conditions are primarily the same as the aforementioned TGVI facility except this facility ranks junior to repayment of TGVI's Class B subordinated debt, which is held by its parent company, Terasen. At December 31, 2006, TGVI had outstanding bankers' acceptances under the C$350 million credit facility with an average term of less than three months. While the bankers' acceptances are short term, the underlying credit facility on which the bankers' acceptances are committed is open through January 2011. Accordingly, under the C$350 million credit facility, borrowings outstanding at December 31, 2006 of $230.8 million have been classified as long-term debt and an estimated $23.2 million as current maturities in our accompanying Consolidated Balance Sheet at a weighted-average interest rate of 4.41%. For the twelve months ended December 31, 2006, average borrowings were $288.8 million at a weighted-average rate of 4.18%. Borrowings outstanding against the $20 million credit facility at December 31, 2006 were $3.2 million at a weighted-average interest rate of 4.32%.

During 2005, we sold a total of 5.67 million Kinder Morgan Management shares that we owned for approximately $254.8

million. We recognized pre-tax gains totaling $78.5 million associated with these sales. These sales allowed us to fully utilize a capital loss carryforward that was scheduled to expire in 2005.

As discussed in Note 4 of the accompanying Notes to Consolidated Financial Statements, on November 30, 2005, we completed the acquisition of Terasen. Terasen shareholders were able to elect, for each Terasen share held, either (i) C$35.75 in cash, (ii) 0.3331 shares of Kinder Morgan common stock, or (iii) C$23.25 in cash plus 0.1165 shares of Kinder Morgan common stock. In the aggregate, we issued approximately $1.1 billion (12.48 million shares) of Kinder Morgan common stock and paid approximately C$2.49 billion (US$2.13 billion) in cash to Terasen securityholders. In addition, our short-term and long-term debt balances increased by approximately $0.6 billion and $2.1 billion, respectively, as a result of including the debt of Terasen and its subsidiaries in our consolidated balances. See Note 10 of the accompanying Notes to Consolidated Financial Statements for additional information regarding the debt of Terasen.

On November 23, 2005, 1197774 Alberta ULC, a wholly owned subsidiary of Kinder Morgan, Inc., entered into a 364-day credit agreement, with Kinder Morgan, Inc. as guarantor, which provides for a committed credit facility in the Canadian dollar equivalent of US$2.25 billion. This credit facility was used to finance the cash portion of the acquisition of Terasen (see Items 1 and 2 "Business and Properties"). Under this bank facility, a facility fee was required to be paid based on the total commitment, whether used or unused, at a rate that varies based on Kinder Morgan, Inc.'s senior debt rating. On November 30, 2005, 1197774 Alberta ULC borrowed approximately $2.1 billion under this facility to finance the cash portion of the acquisition of Terasen. The facility was terminated when the loan was repaid on December 9, 2005 after permanent financing was obtained as discussed further in this section. Interest paid during 2005 under this credit facility was $1.9 million.

On December 9, 2005, Kinder Morgan Finance Company, ULC, a wholly owned subsidiary of Kinder Morgan, Inc., issued $750 million of 5.35% Senior Notes due 2011, $850 million of 5.70% Senior Notes due 2016 and $550 million of 6.40% Senior Notes due 2036. Each series of these notes is fully and unconditionally guaranteed by Kinder Morgan, Inc. on a senior unsecured basis as to principal, interest and any additional amounts required to be paid as a result of any withholding or deduction for Canadian taxes. The proceeds of approximately $2.1 billion, net of underwriting discounts and commissions, were ultimately distributed to repay in full the bridge facility incurred to finance the cash portion of the consideration for Kinder Morgan, Inc.'s acquisition of Terasen. These notes were sold in a private placement pursuant to Rule 144A under the Securities Act of 1933. In February 2006, Kinder Morgan Finance Company, ULC exchanged these notes for substantially identical notes that have been registered under the Securities Act.

On August 5, 2005, we entered into an $800 million five-year senior unsecured revolving credit facility. This credit facility replaced an $800 million five-year senior unsecured revolving credit agreement dated August 18, 2004, effectively extending the maturity of our credit facility by one year, and includes covenants and requires payment of facility fees, which are discussed in Note 10 of the accompanying Notes to Consolidated Financial Statements, that are similar in nature to the covenants and facility fees required by the revolving bank facility it replaced. In this credit facility, the definition of consolidated net worth, which is a component of total capitalization, was revised to exclude other comprehensive income/loss, and the definition of consolidated indebtedness was revised to exclude the debt of Kinder Morgan Energy Partners that is guaranteed by us. On October 6, 2005, we amended our $800 million five-year senior unsecured revolving credit facility (i) to exclude the effect of consolidating Kinder Morgan Energy Partners relating to the requirements of EITF 04-5 discussed previously, (ii) to make administrative changes and (iii) to change definitions and covenants to reflect the inclusion of Terasen as a subsidiary of ours.

On March 15, 2005, we issued $250 million of our 5.15% Senior Notes due March 1, 2015. The proceeds of $248.5 million, net of underwriting discounts and commissions, were used to repay short-term commercial paper debt that was incurred to pay our 6.65% Senior Notes that matured on March 1, 2005.

On March 1, 2005, our $500 million of 6.65% Senior Notes matured, and we paid the holders of the notes, utilizing a combination of cash on hand and borrowings under our commercial paper program.

On November 10, 2004, Kinder Morgan Management closed the issuance and sale of 1,300,000 listed shares in a privately negotiated transaction with a single purchaser. None of the shares in the offering were purchased by us. Kinder Morgan Management used the net proceeds of approximately $52.6 million from the offering to buy additional i-units from Kinder Morgan Energy Partners.

On October 21, 2004, we retired our $75 million 8.75% Debentures due October 15, 2024 at 104.0% of the face amount. We recorded a loss of $2.4 million (net of associated tax benefit of $1.5 million) in connection with this early extinguishment of debt, which is included under the caption "Other, Net" in the accompanying Consolidated Statement of Operations for 2004.

On March 25, 2004, Kinder Morgan Management closed the issuance and sale of 360,664 listed shares in a privately negotiated transaction with a single purchaser. None of the shares in the offering were purchased by us. Kinder Morgan

Management used the net proceeds of approximately $14.9 million from the offering to buy additional i-units from Kinder Morgan Energy Partners.

On August 14, 2001, we announced a plan to repurchase $300 million of our outstanding common stock, which program was increased to $400 million, $450 million, $500 million, $550 million, $750 million, $800 million and $925 million in February 2002, July 2002, November 2003, April 2004, November 2004, April 2005 and November 2005, respectively. As of December 31, 2006, we had repurchased a total of approximately $906.8 million (14,934,300 shares) of our outstanding common stock under the program, of which $31.5 million (339,800 shares), $314.1 million (3,865,800 shares) and $108.6 million (1,695,900 shares) were repurchased in the years ended December 31, 2006, 2005 and 2004, respectively, and none were repurchased in 2007. We ceased additional share repurchases in 2006 in order to fund capital projects, primarily in Canada.

Interest Rate Swaps

On February 21, 2007, we terminated $250 million of our interest rate swap agreements associated with our 7.25% debentures due 2028 and received $19.1 million in cash. This amount will be amortized to interest expense over the period the 7.25% debentures are outstanding.

On February 24, 2006, Terasen terminated its fixed-to-floating interest rate swap agreements associated with its 6.30% and 5.56% Medium Term Notes due 2008 and 2014, respectively, with a notional value of C$195 million, and received proceeds of $1.9 million (C$2.2 million). The cumulative loss recognized of $2.0 million (C$2.3 million) upon early termination of these fair value hedges was recorded under the caption "Long-term Debt: Value of Interest Rate Swaps" in the accompanying Consolidated Balance Sheet at December 31, 2006 and is being amortized to earnings over the original period of the swap transactions. Additionally, Terasen entered into two new interest rate swap agreements with a notional value of C$195 million. These new swaps have also been designated as fair value hedges and qualify for the "shortcut" method of accounting prescribed for qualifying hedges under SFAS No. 133.

On February 10, 2006, we entered into three fixed-to-floating interest rate swap agreements with notional principal amounts of $375 million, $425 million and $275 million, respectively. These swaps effectively convert 50% of the interest expense associated with Kinder Morgan Finance Company, ULC's 5.35% Senior Notes due 2011, 5.70% Senior Notes due 2016 and 6.40% Senior Notes due 2036, respectively, from fixed rates to floating rates based on the three-month LIBOR plus a credit spread. These swaps have been designated as fair value hedges and are accounted for utilizing the "shortcut" method prescribed for qualifying fair value hedges under SFAS No. 133.

In December 2005 we entered into three receive-fixed-rate, pay-fixed-rate U.S. dollar to Canadian dollar cross-currency interest rate swap agreements with Merrill Lynch. These derivative instruments have a combined notional value of C$1,240 million and have been designated as a hedge of our net investment in Canadian operations in accordance with SFAS No. 133.

In December 2005 we entered into three receive-fixed-rate, pay-variable-rate U.S. dollar to Canadian dollar cross-currency interest rate swap agreements with Merrill Lynch. These agreements had a combined notional value of C$1,254 million and did not qualify as a hedge of our net investment in Canadian Operations in accordance with SFAS No. 133. In February 2006 we entered into a series of transactions to effectively terminate these agreements and entered into a series of receive-fixed-rate, pay-fixed-rate U.S. dollar to Canadian dollar cross-currency interest rate swap agreements with a combined notional value of C$1,254 million. The new derivative instruments have been designated as hedges of our net investment in Canadian operations in accordance with SFAS No. 133. We recognized a one time non-cash, after-tax loss of approximately $14 million in the first quarter of 2006 from changes in the fair value of our receive-fixed-rate, pay-variable rate U.S. dollar to Canadian dollar cross-currency interest rate swaps from January 1, 2006 to the termination of the agreements to reflect the strengthening of the Canadian dollar versus the U.S. dollar.

On March 10, 2005, we terminated $250 million of our interest rate swap agreements associated with our 6.50% Senior Notes due 2012 and paid $3.5 million in cash. We are amortizing this amount to interest expense over the period the 6.50% Notes are outstanding. The unamortized balance of $2.7 million at December 31, 2006 is included in the caption "Long-term Debt: Value of Interest Rate Swaps" in the accompanying Consolidated Balance Sheet.

We have invested in entities that are not consolidated in our financial statements. Our obligations with respect to these investments, as well as Kinder Morgan Energy Partners' obligation with respect to a letter of credit, are summarized following.

Off-Balance Sheet Arrangements
At December 31, 2006

Entity	Investment Amount	Investment Percent	Entity Assets[1]	Entity Debt	Our Debt Responsibility
			(Millions of Dollars)		
Ft. Lupton Power Plant	$ 153.9[2]	49.5%	$ 132.5	$ 59.2[3]	$ -
Express System	449.7	33.3%	932.3	475.3	-
CustomerWorks LP	30.0	30%	72.1	-	-
Horizon Pipeline Company	16.0	50%	83.1	49.5[3]	-
Cortez Pipeline Company	16.2	50%	73.7	148.9	74.5[4]
Red Cedar Gathering Company	160.6	49%	247.5	31.4	15.4[5]
West2East Pipeline LLC[6]	-	51%	850.5	790.1	403.0[5]
Nassau County, Florida Ocean Highway and Port Authority	N/A	N/A	N/A	N/A	23.9[7]

1 At recorded value, in each case consisting principally of property, plant and equipment.

2 Does not include any portion of the goodwill recognized in conjunction with the 1998 acquisition of the Thermo Companies.

3 Debtors have recourse only to the assets of the entity, not to the owners.

4 Kinder Morgan Energy Partners is severally liable for its percentage ownership share of the Cortez Pipeline Company debt. Shell Oil Company shares Kinder Morgan Energy Partners' several guaranty obligations jointly and severally; however, Kinder Morgan Energy Partners is obligated to indemnify Shell for liabilities it incurs in connection with such guaranty. Accordingly, in December 2006 and January 2007 Kinder Morgan Energy Partners entered into two separate letters of credit, each in the amount of $37.5 million issued by JP Morgan Chase, in order to secure its indemnification obligations to Shell for 50% of the Cortez debt balance of $148.9 million.

Further, pursuant to a Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company are required to contribute capital to Cortez in the event of a cash deficiency. The agreement contractually supports the financings of Cortez Capital Corporation, a wholly-owned subsidiary of Cortez Pipeline Company, by obligating the partners of Cortez Pipeline to fund cash deficiencies at Cortez Pipeline, including anticipated deficiencies and cash deficiencies relating to the repayment of principal and interest on the debt of Cortez Capital Corporation. The partners' respective parent or other companies further severally guarantee the obligations of the Cortez Pipeline owners under this agreement.

5 Debt responsibility of Kinder Morgan Energy Partners.

6 West2East Pipeline LLC is a limited liability company and is the sole owner of Rockies Express Pipeline LLC. As of December 31, 2006, the remaining limited liability member interests in West2East Pipeline LLC are owned by ConocoPhillips (24%) and Sempra Energy (25%). Kinder Morgan Energy Partners owned a 66 2/3% ownership interest in West2East Pipeline LLC from October 21, 2005 until June 30, 2006, and included its results in its consolidated financial statements until June 30, 2006. On June 30, 2006, Kinder Morgan Energy Partners' ownership interest was reduced to 51%, West2East Pipeline LLC was deconsolidated, and Kinder Morgan Energy Partners subsequently accounted for its investment under the equity method of accounting.

7 Arose from Kinder Morgan Energy Partners' Vopak terminal acquisition in July 2001. Nassau County, Florida Ocean Highway and Port Authority is a political subdivision of the State of Florida. During 1990, Ocean Highway and Port Authority issued its Adjustable Demand Revenue Bonds in the aggregate principal amount of $38.5 million for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. A letter of credit was issued as security for the Adjustable Demand Revenue Bonds and was guaranteed by the parent company of Nassau Terminals LLC, the operator of the port facilities. In July 2002, Kinder Morgan Energy Partners acquired Nassau Terminals LLC and became guarantor under the letter of credit agreement. In December 2002, Kinder Morgan Energy Partners issued a $28 million letter of credit under its credit facilities and the former letter of credit guarantee was terminated. As of December 31, 2006, the value of this letter of credit outstanding under Kinder Morgan Energy Partners' credit facility was $23.9 million. Principal payments on the bonds are made on the first of December each year and reductions are made to the letter of credit.

Aggregate Contractual Obligations

		Amount of Commitment Expiration Per Period			
	Total	**Less than 1 year**	**2-3 years**	**4-5 years**	**After 5 years**
			(In millions)		
Contractual Obligations:					
Short-term Borrowings	$ 1,665.3	$1,665.3	$ -	$ -	$ -
Long-term Debt, Including Current Maturities:					
Principal Payments	11,539.9	511.2	971.3	2,091.5	7,965.9
Interest Payments[1]	10,181.9	784.4	1,334.0	1,180.8	6,882.7
Capital Lease Obligations[2]	8.0	1.5	2.8	2.7	1.0
Operating Leases[3]	923.2	98.4	141.8	117.9	565.1
Gas Purchase Contracts[4]	524.7	450.8	65.0	8.9	-
Other Long-term Obligations	195.0	48.6	63.4	76.0	7.0
Pension and Postretirement Benefit Plans[5]	22.9	1.9	4.1	4.4	12.5
Total Contractual Cash Obligations	$ 25,060.9	$3,562.1	$2,582.4	$3,482.2	$15,434.2
Other Commercial Commitments:					
Standby Letters of Credit[6]	$ 616.9	$ 558.7	$ 20.2	$ 0.5	$ 37.5
Capital Expenditures[7]	$ 796.4	$ 796.4	$ -	$ -	$ -

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1 Interest payments have not been adjusted for any amounts receivable related to our interest rate swaps outstanding. See Item 7A Quantitative and Qualitative Disclosures About Market Risk.

2 Includes obligations under Terasen Gas vehicle leases.

3 Approximately $478.6 million, $20.4 million, $41.2 million, $41.4 million and $375.6 million in each respective column is attributable to the lease obligation associated with the Jackson, Michigan power generation facility.

4 Terasen Gas and TGVI have entered into gas purchase contracts, which represent future purchase obligations. Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts shown reflect index prices that were in effect at December 31, 2006. Kinder Morgan Retail is obligated under certain gas purchase contracts, dating from 1973, to purchase natural gas at fixed and escalating prices from a certain field in Montana.

5 In addition to the amounts shown, we are also required to contribute $8.7 million per year to these plans. We currently do not expect to make any additional significant contributions to these plans in the next few years, although we could elect or be required to make such contributions depending on, among other factors, the return generated by plan assets and changes in actuarial assumptions.

6 The $616.9 million in letters of credit outstanding at December 31, 2006 consisted of the following: (i) four letters of credit, totaling $272 million, supporting our hedging of commodity risk, (ii) two letters of credit, totaling $52.8 million securing accrued unfunded retirement obligations to certain current and retired executives and employees of Terasen, (iii) a combined $39.7 million in two letters of credit supporting the construction of Kinder Morgan Energy Partners' Kinder Morgan Louisiana Pipeline, (iv) a $37.5 million letter of credit supporting Kinder Morgan Energy Partners' indemnification obligations on the Series D note borrowings of Cortez Capital Corporation, (v) Kinder Morgan Energy Partners' $30.3 million guarantee under letters of credit supporting its International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds, (vi) three letters of credit, totaling $29.0 million to secure obligations for construction of new pump stations on the Trans Mountain system, (vii) a $25.4 million letter of credit supporting Kinder Morgan Energy Partners' Kinder Morgan Liquids Terminals LLC New Jersey Economic Development Revenue Bonds, (viii) a $24.1 million letter of credit supporting Kinder Morgan Energy Partners' Kinder Morgan Operating L.P. "B" tax-exempt bonds, (ix) a $23.9 million letter of credit supporting Nassau County, Florida Ocean Highway and Port Authority tax-exempt bonds, (x) four letters of credit, totaling $21.4 million, required under provisions of our property and casualty, worker's compensation and general liability insurance policies, (xi) a $15.3 million letter of credit to fund the Debt Service Reserve Account required under the Express System's trust indenture, (xii) a $10.6 million letter of credit supporting the subordination of operating fees payable to us for operation of the Jackson, Michigan power generation facility to payments due under the operating lease of the facilities and (xiii) 41 letters of credit, totaling $34.9 million supporting various company functions.

7 The 2007 capital expenditure budget totals approximately $2,532.3 million, of which $6.3 million is attributable to our discontinued U.S.-based natural gas distribution operations. Depending on the timing of when our proposed sales of assets take place during 2007, our total capital expenditures may be reduced from the 2007 budget amount. Approximately

$796.4 million of the 2007 capital expenditure budget amount had been committed for the purchase of plant and equipment at December 31, 2006, of which $4.9 million is attributable to our discontinued U.S.-based natural gas distribution operations.

We expect to have sufficient liquidity to satisfy our near-term obligations through the combination of free cash flow and our credit facilities.

Contingent Liabilities:	Contingency	Amount of Contingent Liability at December 31, 2006
Guarantor of the Bushton Gas Processing Plant Lease[1]	Default by ONEOK, Inc.	Total $127.2 million; Averages $23 million per year through 2012
Jackson, Michigan Power Plant Incremental Investment	Operational Performance	$3 to 8 million per year for 12 years
Jackson, Michigan Power Plant Incremental Investment	Cash Flow Performance	Up to a total of $25 million beginning in 2018

[1] In conjunction with our sale of the Bushton gas processing facility to ONEOK, Inc., at December 31, 1999, ONEOK became primarily liable under the associated operating lease and we became secondarily liable. Should ONEOK, Inc. fail to make payments as required under the lease, we would be required to make such payments, with recourse only to ONEOK.

Investment in Kinder Morgan Energy Partners

At December 31, 2006, we owned, directly, and indirectly in the form of i-units corresponding to the number of shares of Kinder Morgan Management we owned, approximately 29.97 million limited partner units of Kinder Morgan Energy Partners. These units, which consist of 14.36 million common units, 5.31 million Class B units and 10.30 million i-units, represent approximately 13.0% of the total limited partner interests of Kinder Morgan Energy Partners. In addition, we are the sole stockholder of the general partner of Kinder Morgan Energy Partners, which holds an effective 2% interest in Kinder Morgan Energy Partners and its operating partnerships. Together, our limited partner and general partner interests represented approximately 14.7% of Kinder Morgan Energy Partners' total equity interests at December 31, 2006.

Prior to our adoption of EITF No. 04-5, we accounted for our investment in Kinder Morgan Energy Partners under the equity method of accounting. Due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts, balances and results of operations of Kinder Morgan Energy Partners are included in our consolidated financial statements and we no longer apply the equity method of accounting to our investment in Kinder Morgan Energy Partners. The adoption of EITF No. 04-5 affects the reported amounts of our consolidated revenues and expenses and our reported segment earnings. However, after taking into account the associated minority interests, the adoption of EITF No. 04-5 has no impact on our income from continuing operations or our net income.

Cash Flows

The following discussion of cash flows should be read in conjunction with the accompanying Consolidated Statements of Cash Flows and related supplemental disclosures. As discussed in Note 1(B) of the accompanying Notes to Consolidated Financial Statements, due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts, balances and results of operations of Kinder Morgan Energy Partners are included in our consolidated financial statements and we no longer apply the equity method of accounting to our investment in Kinder Morgan Energy Partners. All highly liquid investments purchased with an original maturity of three months or less are considered to be cash equivalents.

Net Cash Flows from Operating Activities

"Net Cash Flows Provided by Operating Activities" increased from $616.2 million in 2005 to $1,707.3 million in 2006, an increase of $1,091.1 million. This positive variance was principally due to (i) an increase of $1,518.8 million of net income, net of non-cash items including depreciation and amortization, deferred income taxes, undistributed earnings from equity investments, minority interests in income of consolidated subsidiaries, net gains and losses on sales of assets and property casualty indemnifications, foreign currency gains, mark-to-market interest rate swap loss, losses from impairment of power equipment and losses from discontinued operations ($1,219.6 million and $138.0 million of this $1,518.8 million increase are attributable to Kinder Morgan Energy Partners and Terasen, respectively), (ii) a $134.8 million increase in cash relative to net changes in working capital items, of which Kinder Morgan Energy Partners contributed a decrease of $34.8 million and Terasen contributed an increase of $40.6 million, (iii) the fact that 2005 included a $25.0 million pension payment and (iv) an

$11.4 million source of cash attributable to Terasen rate stabilization accounts. These positive impacts were partially offset by (i) a $464.1 million decrease in distributions received from equity investments, of which the inclusion of the accounts, balances and results of operations of Kinder Morgan Energy Partners in our consolidated financial statements contributed a decrease of $463.0 million, (ii) a net increased use of cash of $51.6 million for gas in underground storage, of which Kinder Morgan Energy Partners and Terasen contributed $2.3 million and $9.8 million, respectively, (iii) $15.4 million of payments made for natural gas liquids inventory entirely attributable to Kinder Morgan Energy Partners, (iv) $19.1 million of payments made to certain shippers on Kinder Morgan Energy Partners' Pacific operations' pipelines as a result of a settlement agreement reached in May 2006 regarding delivery tariffs and gathering enhancement fees at its Watson Station (see Note 19 of the accompanying Notes to Consolidated Financial Statements), (v) the fact that 2005 included a $3.5 million non-cash debit to income for hedging ineffectiveness and (vi) a decrease of $34.4 million in 2006 cash attributable to discontinued operations (see Note 7 of the accompanying Notes to Consolidated Financial Statements.) Significant period-to-period variations in cash used or generated from gas in storage transactions are due to changes in injection and withdrawal volumes as well as fluctuations in natural gas prices.

"Net Cash Flows Provided by Operating Activities" decreased from $644.4 million in 2004 to $616.2 million in 2005, a decrease of $28.2 million (4.4%). This negative variance was principally due to (i) a decrease of $41.2 million of net income, net of non-cash items including depreciation and amortization, deferred income taxes, undistributed earnings from equity investments, minority interests in income of consolidated subsidiaries, net gains and losses on sales of assets, foreign currency gains, amortization of interest rate swap gains, losses from impairment of power equipment and losses from discontinued operations, (ii) a $40.2 million increased use of working capital cash for hedging activities, due to increases in NGPL hedge volumes and natural gas prices, (iii) a $25.0 million pension payment and an $8.5 million postretirement benefit plan payment, both made during 2005, (iv) a $59.9 million increase in cash paid for income taxes during 2005, (v) a $22.4 million increase in cash paid for interest during 2005 and (vi) $6.8 million of severance and other payments to employees resulting from the acquisition of Terasen. See Note 4 of the accompanying Notes to Consolidated Financial Statements. These negative impacts were partially offset by (i) a $95.5 million increase in cash distributions received in 2005 attributable to our interest in Kinder Morgan Energy Partners (see the discussion following), (ii) a net increased source of cash of $28.8 million for gas in underground storage and (iii) an increase of $40.2 million in 2005 cash attributable to discontinued operations, of which $26.7 million is attributable to our discontinued U.S.-based natural gas distribution operations and $10.0 million is attributable to Terasen's discontinued Water and Utility Services (see Note 7 of the accompanying Notes to Consolidated Financial Statements.)

In general, distributions from Kinder Morgan Energy Partners are declared in the month following the end of the quarter to which they apply and are paid in the month following the month of declaration to the general partner and unit holders of record as of the end of the month of declaration. Therefore, the accompanying Statements of Consolidated Cash Flows for 2005 and 2004 reflect the receipt of $530.8 million and $435.3 million, respectively, of cash distributions from Kinder Morgan Energy Partners for (i) the fourth quarter of 2004 and the first nine months of 2005 and (ii) the fourth quarter of 2003 and the first nine months of 2004, respectively. The cash distributions attributable to our interest for the three months and twelve months ended December 31, 2005 total $145.8 million and $552.2 million, respectively. The cash distributions attributable to our interest for the three months and twelve months ended December 31, 2004 total $124.4 million and $458.3 million, respectively. The increases in distributions during 2005 reflect, among other factors, acquisitions made by Kinder Morgan Energy Partners and improvements in its results of operations. Summarized financial information for Kinder Morgan Energy Partners is contained in Note 2 of the accompanying Notes to Consolidated Financial Statements.

Net Cash Flows from Investing Activities

"Net Cash Flows Used in Investing Activities" decreased from $1,978.7 million in 2005 to $1,795.9 million in 2006, a decrease of $182.8 million. This decreased use of cash was principally due to (i) the fact that 2005 included $2,065.5 million of cash used to acquire Terasen Inc. (See Note 4 of the accompanying Notes to Consolidated Financial Statements), (ii) a $96.3 million increase in proceeds from sales of other assets net of removal costs, of which $70.8 million is attributable to Kinder Morgan Energy Partners, (iii) $13.1 million of cash received in 2006 for property casualty indemnifications, (iv) $112.9 million of proceeds received for the sale of Terasen's discontinued Water and Utility Services and (v) an $11.1 million increase during 2006 of proceeds from margin deposits associated with hedging activities utilizing energy derivative instruments, of which proceeds of $2.3 million is attributable to Kinder Morgan Energy Partners. These factors were partially offset by (i) $396.5 million of cash used to acquire Entrega Pipeline LLC and various other assets (See Note 4 of the accompanying Notes to Consolidated Financial Statements), (ii) an additional $10.6 million attributable to the acquisition of Terasen (See Note 4 of the accompanying Notes to Consolidated Financial Statements), (iii) a $1,438.6 million increased use of cash for capital expenditures, of which $1,058.3 million and $316.6 million are attributable to Kinder Morgan Energy Partners and Terasen, respectively, (iv) the fact that 2005 included $254.8 million of proceeds from the sale of Kinder Morgan Management, LLC shares (see Note 5 of the accompanying Notes to Consolidated Financial Statements) and (v) $12.9 million for investments in underground natural gas storage volumes and payments made for natural gas liquids line-fill, all of which is attributable to Kinder Morgan Energy Partners.

"Net Cash Flows Used in Investing Activities" increased from $7.3 million in 2004 to $1,978.7 million in 2005, an increase of $1,971.4 million. This increased use of cash was principally due to (i) $2,065.5 million of cash used to acquire Terasen Inc. (See Note 4 of the accompanying Notes to Consolidated Financial Statements), (ii) a $41.3 million increase in capital expenditures during 2005, (iii) the fact that 2004 included $210.8 million of proceeds received from Kinder Morgan Energy Partners for the contribution of TransColorado, and (iv) the fact that 2004 included $42.1 million of proceeds from the sales of turbines. These factors were partially offset by (i) $48.4 million net decreased 2005 investments in margin deposits associated with hedging activities utilizing energy derivative instruments, (ii) $254.8 million of proceeds received in 2005 from the sale of Kinder Morgan Management shares, (see Note 5 of the accompanying Notes to Consolidated Financial Statements), (iii) an $18.9 million decreased use of cash in 2005 attributable to discontinued operations (see Note 7 of the accompanying Notes to Consolidated Financial Statements.) and (iv) the fact that 2004 included an additional $69.5 million investment in Kinder Morgan Energy Partners, which primarily consisted of Kinder Morgan Management's purchase of additional i-units from Kinder Morgan Energy Partners with the proceeds of an issuance of its shares as discussed under "Net Cash Flows from Financing Activities" following.

Net Cash Flows from Financing Activities

"Net Cash Flows Provided by (Used in) Financing Activities" decreased from $1,302.3 million in 2005 to $88.7 million in 2006, a decrease of $1,213.6 million. This decrease was principally due to (i) the fact that 2005 includes $2,137.2 million of proceeds, net of issuance costs, from the issuance of our wholly owned subsidiary, Kinder Morgan Finance Company's (a) $750 million of 5.35% Senior Notes due January 5, 2011, (b) $850 million of 5.70% Senior Notes due January 5, 2016 and (c) $550 million of 6.40% Senior Notes due January 5, 2036, (ii) $125 million of cash used to retire our 7.35% Series debentures which were elected by the holders to be redeemed on August 1, 2006 as provided in the indenture governing the debentures (iii) the fact that 2005 included $248.5 million of proceeds, net of issuance costs, from the issuance of our 5.15% Senior Notes due March 1, 2015, (iv) $181.7 million of cash used to retire TGVI's Syndicated Credit Facility, $86.8 million of cash used to retire Terasen's 4.85% Series 2 Medium Term Notes and $104.1 million of cash used to retire Terasen Gas Inc.'s 6.15% Series 16 Medium Term Notes and 9.75% Series D Medium Term Notes (see Note 10 of the accompanying Notes to Consolidated Financial Statements), (v) an increase of $572.6 million of minority interest distributions, principally consisting of Kinder Morgan Energy Partners' $465.7 million distribution to common unit owners and $105.2 million paid from Kinder Morgan Energy Partners' Rockies Express Pipeline LLC subsidiary to Sempra Energy, (vi) an $113.3 million increase in cash paid for dividends in 2006, principally due to the increased dividends declared per share and (vii) a decrease of $24.1 million for issuance of our common stock, principally due to a reduction of employee stock option exercises. Partially offsetting these factors were (i) the fact that 2005 included $500 million of cash used to retire our $500 million 6.65% Senior Notes, (ii) $260.0 million of proceeds received in 2006 from the issuance of TGVI's Floating Rate Syndicated Credit Facility, (iii) $104.1 million of proceeds, net of issuance costs, received in 2006 from the issuance of Terasen Gas Inc.'s 5.55% Medium Term Note Debentures due September 25, 2036 (see Note 10 of the accompanying Notes to Consolidated Financial Statements), (iv) a $282.8 million decrease in cash paid during 2006 to repurchase our common shares, (v) an $861.5 million increase in short-term debt, of which $944.5 million of additional borrowing is attributable to Kinder Morgan Energy Partners and a $123.1 million reduction in short-term debt is attributable to Terasen, (vi) $353.8 million of contributions from minority interest owners, primarily Kinder Morgan Energy Partners' issuance of 5.75 million common units receiving net proceeds (after underwriting discount) of $248.0 million and Sempra Energy's $104.2 million contribution for its 33 1/3% share of the purchase price of Entrega Pipeline LLC, (vii) a $17.9 million increase from net changes in cash book overdrafts—which represent checks issued but not yet endorsed, and (viii) a $6.8 million decreased use of cash during 2006 for short-term advances to unconsolidated affiliates, principally Kinder Morgan Energy Partners, during 2005.

"Net Cash Flows Provided by (Used in) Financing Activities" increased from a use of $471.7 million in 2004 to a source of $1,302.3 million in 2005, an increase of $1,774.0 million. This increase was principally due to (i) $2,137.2 million of proceeds, net of issuance costs, received in 2005 from the issuance of our wholly owned subsidiary, Kinder Morgan Finance Company's (a) $750 million of 5.35% Senior Notes due January 5, 2011, (b) $850 million of 5.70% Senior Notes due January 5, 2016 and (c) $550 million of 6.40% Senior Notes due January 5, 2036, (ii) $248.5 million of proceeds, net of issuance costs, received in 2005 from the issuance of our 5.15% Senior Notes due March 1, 2015 (See Note 10 of the accompanying Notes to Consolidated Financial Statements), (iii) $39.6 million of short-term borrowings in 2005 versus a $127.9 million reduction in short-term debt in 2004 and (iv) the fact that 2004 included $78 million of cash used for the early retirement of our $75 million 8.75% Debentures due October 15, 2024. Partially offsetting these factors were (i) $500 million of cash used in 2005 to retire our $500 million 6.65% Senior Notes, (ii) a $214.4 million increase in cash paid during 2005 to repurchase our common shares, (iii) a $76.5 million increase in cash paid for dividends in 2005, principally due to the increased dividends declared per share (see discussion following in this section) and (iv) the fact that 2004 included $67.6 million of proceeds, net of issuance costs, from the issuance of Kinder Morgan Management shares.

Total cash payments for dividends were $468.5 million, $355.2 million and $278.7 million in 2006, 2005 and 2004, respectively. The increases in these amounts are principally due to increases in the dividends declared per common share and, to a minor extent, to increased shares outstanding. On February 14, 2007, we paid a dividend of $0.875 per share to shareholders of record as of January 31, 2007.

Minority Interests Distributions to Kinder Morgan Energy Partners' Common Unit Holders

Kinder Morgan Energy Partners' partnership agreement requires that it distribute 100% of "Available Cash," as defined in its partnership agreement, to its partners within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available Cash consists generally of all of Kinder Morgan Energy Partners' cash receipts, including cash received by its operating partnerships and net reductions in reserves, less cash disbursements and net additions to reserves and amounts payable to the former general partner of SFPP, in respect of its remaining 0.5% interest in SFPP.

Kinder Morgan Management, as the delegate of Kinder Morgan G.P., Inc., our wholly owned subsidiary and the general partner of Kinder Morgan Energy Partners, is granted discretion to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, rate refunds and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When Kinder Morgan Management determines Kinder Morgan Energy Partners' quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Available cash is initially distributed 98% to Kinder Morgan Energy Partners' limited partners with 2% retained by Kinder Morgan G.P., Inc. as Kinder Morgan Energy Partners' general partner. These distribution percentages are modified to provide for incentive distributions to be retained by Kinder Morgan G.P., Inc. as general partner of Kinder Morgan Energy Partners in the event that quarterly distributions to unitholders exceed certain specified targets.

Available cash for each quarter is distributed:

- first, 98% to the owners of all classes of units pro rata and 2% to Kinder Morgan G.P., Inc. as general partner of Kinder Morgan Energy Partners until the owners of all classes of units have received a total of $0.15125 per unit in cash or equivalent i-units for such quarter;

- second, 85% of any available cash then remaining to the owners of all classes of units pro rata and 15% to Kinder Morgan G.P., Inc. as general partner of Kinder Morgan Energy Partners until the owners of all classes of units have received a total of $0.17875 per unit in cash or equivalent i-units for such quarter;

- third, 75% of any available cash then remaining to the owners of all classes of units pro rata and 25% to Kinder Morgan G.P., Inc. as general partner of Kinder Morgan Energy Partners until the owners of all classes of units have received a total of $0.23375 per unit in cash or equivalent i-units for such quarter; and

- fourth, 50% of any available cash then remaining to the owners of all classes of units pro rata, to owners of common units in cash and to Kinder Morgan Management as owners of i-units in the equivalent number of i-units, and 50% to Kinder Morgan G.P., Inc. as general partner of Kinder Morgan Energy Partners.

During 2006, Kinder Morgan Energy Partners paid distributions of $3.23 per common unit for the year ended December 31, 2006, of which $465.7 million was paid to the public holders (represented in minority interests) of Kinder Morgan Energy Partners' common units.

On January 17, 2007, Kinder Morgan Energy Partners declared a quarterly distribution of $0.83 per unit for the quarterly period ended December 31, 2006. The distribution was paid on February 14, 2007, to unitholders of record as of January 31, 2007.

Litigation and Environmental Matters

We recorded a total reserve for environmental claims, without discounting and without regard to anticipated insurance recoveries, of $77.8 million and $16.8 million at December 31, 2006 and 2005, respectively. In addition, we recorded a receivable of $28.1 million and $3.6 million at December 31, 2006 and 2005, respectively, for expected cost recoveries that have been deemed probable. The reserve is primarily established to address and clean up soil and ground water impacts from former releases to the environment at facilities we have acquired or accidental spills or releases at facilities that we own. Reserves for each project are generally established by reviewing existing documents, conducting interviews and performing site inspections to determine the overall size and impact to the environment. Reviews are made on a quarterly basis to determine the status of the cleanup and the costs associated with the effort. In assessing environmental risks in conjunction with proposed acquisitions, we review records relating to environmental issues, conduct site inspections, interview employees, and, if appropriate, collect soil and groundwater samples.

Additionally, we recorded a total reserve for legal fees, transportation rate cases and other litigation liabilities in the amount of $114.7 million and $6.5 million at December 31, 2006 and 2005, respectively. The reserve is primarily related to various claims from lawsuits arising from Kinder Morgan Energy Partners' Pacific operations' pipeline transportation rates, and the contingent amount is based on both the circumstances of probability and reasonability of dollar estimates. We regularly assess the likelihood of adverse outcomes resulting from these claims in order to determine the adequacy of our liability provision.

Though no assurance can be given, we believe we have established adequate environmental and legal reserves such that the resolution of pending environmental matters and litigation will not have a material adverse impact on our business, cash flows, financial position or results of operations.

Pursuant to our continuing commitment to operational excellence and our focus on safe, reliable operations, we have implemented, and intend to implement in the future, enhancements to certain of our operational practices in order to strengthen our environmental and asset integrity performance. These enhancements have resulted and may result in higher operating costs and sustaining capital expenditures; however, we believe these enhancements will provide us the greater long term benefits of improved environmental and asset integrity performance.

Please refer to Notes 18 and 19, respectively, to our consolidated financial statements included elsewhere in this report for additional information regarding pending litigation, environmental and asset integrity matters.

Regulation

The Pipeline Safety Improvement Act of 2002 requires pipeline companies to perform integrity tests on natural gas transmission pipelines that exist in high population density areas that are designated as High Consequence Areas. Pipeline companies are required to perform the integrity tests within ten years of December 17, 2002, the date of enactment, and must perform subsequent integrity tests on a seven year cycle. At least 50% of the highest risk segments must be tested within five years of the enactment date. The risk ratings are based on numerous factors, including the population density in the geographic regions served by a particular pipeline, as well as the age and condition of the pipeline and its protective coating. Testing will consist of hydrostatic testing, internal electronic testing, or direct assessment of the piping. A similar integrity management rule for refined petroleum products pipelines became effective May 29, 2001. All baseline assessments for products pipelines must be completed by March 31, 2008. We have included all incremental expenditures estimated to occur during 2007 associated with the Pipeline Safety Improvement Act of 2002 and the integrity management of our products pipelines in our 2007 budget and capital expenditure plan.

Please refer to Note 18 to our consolidated financial statements included elsewhere in this report for additional information regarding regulatory matters.

Recent Accounting Pronouncements

Refer to Note 20 of the accompanying Notes to Consolidated Financial Statements for information regarding recent accounting pronouncements.

Information Regarding Forward-looking Statements

This filing includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "intend," "plan," "projection," "forecast," "strategy," "position," "continue," "estimate," "expect," "may," or the negative of those terms or other variations of them or comparable terminology. In particular, statements, express or implied, concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow or to service debt or to pay dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from those in the forward-looking statements include:

- the occurrence of any event, change or other circumstance that could give rise to the termination of the merger agreement in connection with the Going Private transaction;

- the inability to complete the Going Private transaction due to the failure to satisfy any conditions required to consummate the merger;

- price trends and overall demand for natural gas liquids, refined petroleum products, oil, carbon dioxide, natural gas, electricity, coal and other bulk materials and chemicals in North America;

- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;
- changes in our tariff rates or those of Kinder Morgan Energy Partners implemented by the FERC, the BCUC or another regulatory agency or, with respect to Kinder Morgan Energy Partners, the California Public Utilities Commission;
- Kinder Morgan Energy Partners' ability and our ability to acquire new businesses and assets and integrate those operations into existing operations, as well as the ability to expand our respective facilities;
- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from Kinder Morgan Energy Partners' terminals or pipelines or our terminals or pipelines;
- Kinder Morgan Energy Partners' ability and our ability to successfully identify and close acquisitions and make cost-saving changes in operations;
- shut-downs or cutbacks at major refineries, petrochemical or chemical plants, ports, utilities, military bases or other businesses that use Kinder Morgan Energy Partners' or our services or provide services or products to Kinder Morgan Energy Partners or us;
- crude oil and natural gas production from exploration and production areas that we serve, such as the Permian Basin area of West Texas, the U.S. Rocky Mountains and the Alberta oilsands;
- changes in laws or regulations, third-party relations and approvals, decisions of courts, regulators and governmental bodies that may adversely affect our business or our ability to compete;
- changes in accounting pronouncements that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;
- our ability to offer and sell equity securities and debt securities or obtain debt financing in sufficient amounts to implement that portion of our business plan that contemplates growth through acquisitions of operating businesses and assets and expansions of our facilities;
- our indebtedness could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, and/or place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- interruptions of electric power supply to our facilities due to natural disasters, power shortages, strikes, riots, terrorism, war or other causes;
- our ability to obtain insurance coverage without significant levels of self-retention of risk;
- acts of nature, sabotage, terrorism or other similar acts causing damage greater than our insurance coverage limits;
- capital markets conditions;
- the political and economic stability of the oil producing nations of the world;
- national, international, regional and local economic, competitive and regulatory conditions and developments;
- our ability to achieve cost savings and revenue growth;
- inflation;
- interest rates;
- the pace of deregulation of retail natural gas and electricity;
- foreign exchange fluctuations;
- the timing and extent of changes in commodity prices for oil, natural gas, electricity and certain agricultural products;

- the extent of Kinder Morgan Energy Partners' success in discovering, developing and producing oil and gas reserves, including the risks inherent in exploration and development drilling, well completion and other development activities;

- engineering and mechanical or technological difficulties that Kinder Morgan Energy Partners may experience with operational equipment, in well completions and workovers, and in drilling new wells;

- the uncertainty inherent in estimating future oil and natural gas production or reserves that Kinder Morgan Energy Partners may experience;

- the ability to complete expansion projects on time and on budget;

- the timing and success of Kinder Morgan Energy Partners' and our business development efforts; and

- unfavorable results of litigation and the fruition of contingencies referred to in the accompanying Notes to Consolidated Financial Statements.

There is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, what impact they will have on our results of operations or financial condition. Because of these uncertainties, you should not put undue reliance on any forward-looking statements. See Item 1A "Risk Factors" for a more detailed description of these and other factors that may affect the forward-looking statements. When considering forward-looking statements, one should keep in mind the risk factors described in "Risk Factors" above. The risk factors could cause our actual results to differ materially from those contained in any forward-looking statement. Other than as required by applicable law, we disclaim any obligation to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk.*

Generally, our market risk sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in interest rates or commodity prices. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated, based on actual fluctuations in interest rates or commodity prices and the timing of transactions.

For a full discussion of our risk management activities, see Note 12 of the accompanying Notes to Consolidated Financial Statements.

Energy Commodity Market Risk

We measure the risk of price changes in the natural gas, natural gas liquids and crude oil markets utilizing a value-at-risk model. Value-at-risk is a statistical measure of how much the mark-to-market value of a portfolio could change during a period of time, within a certain level of statistical confidence. We utilize a closed form model to evaluate risk on a daily basis. The value-at-risk computations utilize a confidence level of 97.7% for the resultant price movement and a holding period of one day is chosen for the calculation. The confidence level used means that there is a 97.7% probability that the mark-to-market losses for a single day will not exceed the value-at-risk number presented. Financial instruments evaluated by the model include commodity futures and options contracts, fixed price swaps, basis swaps and over-the-counter options.

For the year ended December 31, 2006, value-at-risk reached a high of $2.2 million and a low of $0.6 million. Value-at-risk as of December 31, 2006, was $0.6 million and, based on quarter-end values, averaged $1.4 million for 2006.

Our calculated value-at-risk exposure represents an estimate of the reasonably possible net losses that would be recognized on our portfolio of derivatives assuming hypothetical movements in future market rates, and is not necessarily indicative of actual results that may occur. It does not represent the maximum possible loss or any expected loss that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ from estimates due to actual fluctuations in market rates, operating exposures and the timing thereof, as well as changes in our portfolio of derivatives during the year. In addition, as discussed above, we enter into these derivatives solely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore, the change in the market value of our portfolio of derivatives, with the exception of a minor amount of hedging inefficiency, is offset by changes in the value of the underlying physical transactions.

Interest Rate Risk

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. The market risk inherent in our debt instruments and positions is the potential change arising from increases or decreases in interest rates.

We enter into interest rate swap agreements for the purposes of hedging the interest rate risk associated with our fixed rate debt obligations and transforming a portion of the underlying cash flows related to our long-term fixed rate debt securities into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. As of December 31, 2006, all of our interest rate swaps represented receive-fixed-rate, pay-variable-rate swaps.

We monitor our mix of fixed rate and variable rate debt obligations in light of changing market conditions and from time to time may alter that mix by, for example, refinancing balances outstanding under our variable rate debt with fixed rate debt (or vice versa) or by entering into interest rate swaps or other interest rate hedging agreements. In general, we attempt to maintain an overall target mix of approximately 50% fixed rate debt and 50% variable rate debt.

Based on the long-term debt effectively converted to floating rate debt as a result of swaps, excluding those swaps where the risk is passed on to customers through rates and excluding the swaps held by Kinder Morgan Energy Partners, the market risk related to a 1% change in interest rates would result in a $27 million annual impact on pre-tax income.

See Note 10 of the accompanying Notes to Consolidated Financial Statements for additional information related to our debt instruments.

Foreign Currency Risk

We are exposed to foreign currency risk from our investments in businesses owned and operated outside the United States. To mitigate this risk, we have several receive-fixed-rate, pay-fixed-rate U.S. dollar to Canadian dollar cross-currency interest rate swap agreements that have been designated as a hedge of our net investment in Canadian operations in accordance with SFAS No. 133.

Although a change in foreign currency exchange rates would not affect our net income, a 1% change in the U.S. Dollar to Canadian Dollar exchange rate would impact the fair value of these swap agreements by approximately $21 million.

Item 8. ***Financial Statements and Supplementary Data.***

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Report of Independent Registered Public Accounting Firm

To the Board of Directors
and Stockholders of Kinder Morgan, Inc.

We have completed integrated audits of Kinder Morgan, Inc.'s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Kinder Morgan, Inc. and its subsidiaries (the "Company") at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1(B) to the consolidated financial statements, the Company changed its method of accounting for its equity investment in Kinder Morgan Energy Partners, L.P. effective January 1, 2006.

As discussed in Note 1(T) to the consolidated financial statements, the Company changed its method of accounting for its share-based compensation effective January 1, 2006.

As discussed in Note 13 to the consolidated financial statements, the Company changed its method of accounting for its defined benefit pension and postretirement plans effective December 31, 2006.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control - Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. As described in Management's Report on Internal Control Over Financial Reporting, management has excluded:

- the various oil and gas properties acquired from Journey Acquisition – I, L.P. and Journey 2000, L.P. on April 5, 2006. The acquisition was made effective March 1, 2006;

- three terminal operations acquired separately in April 2006: terminal equipment and infrastructure located on the Houston Ship Channel, a rail terminal located at the Port of Houston, and all of the membership interests in Lomita Rail Terminal LLC;

- all of the membership interests of Transload Services, LLC, acquired November 20, 2006;

- all of the membership interests of Devco USA L.L.C., acquired December 1, 2006; and

- the refined petroleum products terminal located in Roanoke, Virginia, acquired from Motiva Enterprises, LLC effective December 15, 2006.

(the "Acquired Businesses"), each acquired in separate transactions, from its assessment of internal control over financial reporting as of December 31, 2006 because these businesses were acquired by the Partnership in purchase business combinations during 2006. We have also excluded these Acquired Businesses from our audit of internal control over financial reporting. These Acquired Businesses', in the aggregate, constituted 0.53% and 0.29%, respectively, of total assets and total revenues, of the related consolidated financial statement amounts as of and for the year ended December 31, 2006.

PricewaterhouseCoopers LLP
Houston, Texas
March 1, 2007

CONSOLIDATED STATEMENTS OF OPERATIONS
Kinder Morgan, Inc. and Subsidiaries

	Year Ended December 31,		
	2006	2005	2004
	(In millions except per share amounts)		
Operating Revenues:			
Natural Gas Sales	$ 7,622.0	$ 404.5	$ 130.1
Transportation and Storage	3,276.9	766.5	670.9
Oil and Product Sales	740.2	3.0	-
Other	207.3	80.5	76.7
Total Operating Revenues	11,846.4	1,254.5	877.7
Operating Costs and Expenses:			
Purchases and Other Costs of Sales	7,318.1	458.8	194.2
Operations and Maintenance	1,293.9	145.1	113.5
General and Administrative	369.3	72.3	67.7
Depreciation and Amortization	646.4	113.4	101.6
Taxes, Other Than Income Taxes	214.9	34.5	26.2
Other Expenses (Income)	(34.1)	-	-
Impairment of Assets	651.7	6.5	33.5
Total Operating Costs and Expenses	10,460.2	830.6	536.7
Operating Income	1,386.2	423.9	341.0
Other Income and (Expenses):			
Equity in Earnings of Kinder Morgan Energy Partners	-	605.4	558.1
Equity in Earnings of Other Equity Investments	109.0	16.2	10.1
Interest Expense, Net	(765.3)	(166.3)	(125.3)
Interest Expense – Deferrable Interest Debentures	(21.9)	(21.9)	(21.9)
Interest Expense – Capital Securities	(8.7)	(0.7)	-
Minority Interests	(374.2)	(50.4)	(56.4)
Other, Net	(2.3)	69.2	0.6
Total Other Income and (Expenses)	(1,063.4)	451.5	365.2
Income from Continuing Operations Before Income Taxes	322.8	875.4	706.2
Income Taxes	274.1	345.5	208.0
Income from Continuing Operations	48.7	529.9	498.2
Income from Discontinued Operations, Net of Tax	23.2	24.7	23.9
Net Income	$ 71.9	$ 554.6	$ 522.1
Basic Earnings (Loss) Per Common Share:			
Income from Continuing Operations	$ 0.37	$ 4.29	$ 4.03
Income from Discontinued Operations	0.17	0.20	0.19
Total Basic Earnings Per Common Share	$ 0.54	$ 4.49	$ 4.22
Number of Shares Used in Computing Basic Earnings (Loss) Per Common Share	133.0	123.5	123.8
Diluted Earnings (Loss) Per Common Share:			
Income from Continuing Operations	$ 0.36	$ 4.25	$ 3.99
Income from Discontinued Operations	0.17	0.20	0.19
Total Diluted Earnings Per Common Share	$ 0.53	$ 4.45	$ 4.18
Number of Shares Used in Computing Diluted Earnings (Loss) Per Common Share	135.0	124.6	124.9
Dividends Per Common Share	$ 3.50	$ 2.90	$ 2.25

The accompanying notes are an integral part of these statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Kinder Morgan, Inc. and Subsidiaries

	Year Ended December 31,		
	2006	2005[1]	2004[1]
		(In millions)	
Net Income	$ 71.9	$ 554.6	$ 522.1
Other Comprehensive Income (Loss), Net of Tax:			
Change in Fair Value of Derivatives Utilized for Hedging Purposes (Net of Tax of $26.8 and Tax Benefit of $106.1 and $36.7, respectively)	44.6	(174.7)	(67.1)
Reclassification of Change in Fair Value of Derivatives to Net Income (Net of Tax of $11.9, $60.6 and $21.5, respectively)	21.7	102.3	38.0
Change in Foreign Currency Translation Adjustment	(31.9)	3.4	-
Adjustment to Recognize Minimum Pension Liability (Net of Tax of $1.7 and Tax Benefit of $1.6)	3.5	(3.3)	-
Total Other Comprehensive Income (Loss)	37.9	(72.3)	(29.1)
Comprehensive Income	$ 109.8	$ 482.3	$ 493.0

[1] Changes in Other Comprehensive Income for 2005 and 2004 include decreases of $49.2 million and $36.2 million, respectively, from Kinder Morgan Energy Partners, which we accounted for using the equity method prior to our adoption of EITF No. 04-5 on January 1, 2006.

The accompanying notes are an integral part of these statements.

CONSOLIDATED BALANCE SHEETS
Kinder Morgan, Inc. and Subsidiaries

	December 31, 2006	December 31, 2005
	(In millions)	
ASSETS:		
Current Assets:		
Cash and Cash Equivalents	$ 129.8	$ 116.6
Restricted Deposits	-	10.6
Accounts Receivable, Net:		
Trade	1,173.3	489.0
Related Parties	10.4	17.2
Inventories	275.0	228.2
Gas Imbalances	14.9	16.9
Rate Stabilization	124.3	35.7
Assets Held for Sale	87.9	126.7
Other	204.2	263.2
	2,019.8	1,304.1
Notes Receivable – Related Parties	89.7	-
Investments:		
Kinder Morgan Energy Partners	-	2,202.9
Other	1,084.6	649.6
	1,084.6	2,852.5
Goodwill	3,043.8	2,781.0
Other Intangibles, Net	229.5	17.7
Property, Plant and Equipment, Net	18,839.6	9,545.6
Assets Held for Sale, Non-current	422.3	-
Deferred Charges and Other Assets	1,066.3	950.7
Total Assets	$ 26,795.6	$ 17,451.6

CONSOLIDATED BALANCE SHEETS (continued)
Kinder Morgan, Inc. and Subsidiaries

	December 31, 2006	December 31, 2005
	(In millions)	
LIABILITIES AND STOCKHOLDERS' EQUITY:		
Current Liabilities:		
Current Maturities of Long-term Debt	$ 511.2	$ 347.4
Notes Payable	1,665.3	610.6
Cash Book Overdrafts	59.6	-
Accounts Payable	1,115.5	431.2
Accrued Interest	220.4	92.0
Accrued Taxes	85.5	100.1
Gas Imbalances	29.2	16.1
Rate Stabilization	11.4	115.1
Liabilities Held for Sale	78.3	21.9
Other	840.0	208.2
	4,616.4	1,942.6
Other Liabilities and Deferred Credits:		
Deferred Income Taxes	3,144.0	3,156.4
Liabilities Held for Sale, Non-current	7.9	-
Other	1,349.4	451.5
	4,501.3	3,607.9
Long-term Debt:		
Outstanding Notes and Debentures	10,623.9	6,286.8
Deferrable Interest Debentures Issued to Subsidiary Trusts	283.6	283.6
Capital Securities	106.9	107.2
Value of Interest Rate Swaps	46.4	51.8
	11,060.8	6,729.4
Minority Interests in Equity of Subsidiaries	3,095.5	1,247.3
Commitments and Contingent Liabilities (Notes 19 and 15)		
Stockholders' Equity:		
Preferred Stock (Note 11)	-	-
Common Stock- Authorized – 300,000,000 Shares, Par Value $5 Per Share; Outstanding – 149,166,709 and 148,479,863 Shares, Respectively, Before Deducting 15,022,751 and 14,712,901 Shares Held in Treasury	745.8	742.4
Additional Paid-in Capital	3,048.9	3,056.3
Retained Earnings	778.7	1,175.3
Treasury Stock	(915.9)	(885.7)
Deferred Compensation	-	(36.9)
Accumulated Other Comprehensive Loss	(135.9)	(127.0)
Total Stockholders' Equity	3,521.6	3,924.4
Total Liabilities and Stockholders' Equity	$ 26,795.6	$ 17,451.6

The accompanying notes are an integral part of these statements.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Kinder Morgan, Inc. and Subsidiaries

	Year Ended December 31,					
	2006		2005		2004	
	Shares	Amount	Shares	Amount	Shares	Amount
			(Dollars in millions)			
Common Stock:						
Beginning Balance	148,479,863	$ 742.4	134,198,905	$ 671.0	132,229,622	$ 661.1
Acquisition of Terasen	-	-	12,476,974	62.4	-	-
Employee Benefit Plans	686,846	3.4	1,803,984	9.0	1,969,283	9.9
Ending Balance	149,166,709	745.8	148,479,863	742.4	134,198,905	671.0
Additional Paid-in Capital:						
Beginning Balance		3,056.3		1,863.2		1,780.8
Acquisition of Terasen		-		1,084.4		-
Revaluation of Kinder Morgan Energy Partners (KMP) Investment (Note 5)		(40.3)		7.8		(0.5)
Employee Benefit Plans		33.2		78.9		63.5
Tax Benefits from Employee Benefit Plans		18.6		22.0		19.4
Implementation of SFAS No. 123(R) Deferred Compensation Balance		(36.9)		-		-
Deferred Compensation (Note 14)		18.0		-		-
Ending Balance		3,048.9		3,056.3		1,863.2
Retained Earnings:						
Beginning Balance		1,175.3		975.9		732.5
Net Income		71.9		554.6		522.1
Cash Dividends, Common Stock		(468.5)		(355.2)		(278.7)
Ending Balance		778.7		1,175.3		975.9
Treasury Stock at Cost:						
Beginning Balance	(14,712,901)	(885.7)	(10,666,801)	(558.9)	(8,912,660)	(446.1)
Treasury Stock Acquired	(339,800)	(31.5)	(3,865,800)	(314.1)	(1,695,900)	(108.6)
Employee Benefit Plans	29,950	1.3	(180,300)	(12.7)	(58,241)	(4.2)
Ending Balance	(15,022,751)	(915.9)	(14,712,901)	(885.7)	(10,666,801)	(558.9)
Deferred Compensation Plans:						
Beginning Balance		(36.9)		(31.7)		(36.5)
Current Year Activity (Note 14)		-		(5.2)		4.8
Implementation of SFAS No. 123(R) Balance Transfer to Additional Paid-in Capital		36.9		-		-
Ending Balance		-		(36.9)		(31.7)
Accumulated Other Comprehensive Loss (Net of Tax):						
Derivatives:						
Beginning Balance		(127.1)		(54.7)		(25.6)
Unrealized Gain (Loss) on Derivatives Utilized for Hedging Purposes		66.3		(72.4)		(29.1)
Ending Balance		(60.8)		(127.1)		(54.7)
Foreign Currency Translation:						
Beginning Balance		7.4		-		-
Terasen Acquisition		-		4.0		
Currency Translation Adjustment		(31.9)		3.4		-
Ending Balance		(24.5)		7.4		-
Minimum Pension Liability:						
Beginning Balance		(7.3)		-		-
Terasen Acquisition		-		(4.0)		-
Minimum Pension Liability Adjustments		7.3		(3.3)		-
Ending Balance		-		(7.3)		-
Adjustment to Initially Apply SFAS No. 158		(50.6)		-		-
Total Accumulated Other Comprehensive Loss		(135.9)		(127.0)		(54.7)
Total Stockholders' Equity	134,143,958	$ 3,521.6	133,766,962	$ 3,924.4	123,532,104	$ 2,864.8

The accompanying notes are an integral part of these statements.

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CONSOLIDATED STATEMENTS OF CASH FLOWS
Kinder Morgan, Inc. and Subsidiaries

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS			
Cash Flows from Operating Activities:			
Net Income	$ 71.9	$ 554.6	$ 522.1
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Income from Discontinued Operations, Net of Tax	(23.2)	(24.8)	(23.9)
Loss from Impairment of Assets	651.7	6.5	33.5
Loss on Early Extinguishment of Debt	-	-	3.9
Depreciation and Amortization	646.4	113.4	101.6
Deferred Income Taxes	10.9	92.0	36.4
Equity in Earnings of Kinder Morgan Energy Partners	-	(605.4)	(558.1)
Distributions from Kinder Morgan Energy Partners	-	530.8	435.3
Equity in Earnings of Other Equity Investments	(109.0)	(16.2)	(10.2)
Distributions from Other Equity Investees	74.8	8.1	9.7
Minority Interests in Income of Consolidated Subsidiaries	374.2	50.5	56.4
Change in Rate Stabilization Accounts	6.8	(4.6)	-
Gains from Property Casualty Indemnifications	(15.2)	-	-
Net (Gains) Losses on Sales of Assets	(22.0)	(76.4)	(5.9)
Mark-to-Market Interest Rate Swap Loss	22.3	-	-
Foreign Currency Gain	-	(5.0)	-
Pension Contribution in Excess of Expense	-	(23.8)	(4.6)
Changes in Gas in Underground Storage	(23.6)	28.0	(0.8)
Changes in Working Capital Items [Note 1(R)]	64.4	(70.4)	41.2
(Payment for) Proceeds from Termination of Interest Rate Swap	-	(3.5)	-
Other, Net	(58.7)	(7.6)	(22.0)
Net Cash Flows Provided by Continuing Operations	1,671.7	546.2	614.6
Net Cash Flows Provided by Discontinued Operations	35.6	70.0	29.8
Net Cash Flows Provided by Operating Activities	1,707.3	616.2	644.4
Cash Flows from Investing Activities:			
Capital Expenditures	(1,583.1)	(144.5)	(103.2)
Acquisition of Terasen, Net of Cash Acquired of $73.7	(10.6)	(2,065.5)	-
Other Acquisitions	(396.5)	-	-
Proceeds from Contribution of TransColorado to Kinder Morgan Energy Partners	-	-	210.8
Investment in Kinder Morgan Energy Partners (Note 2)	-	(4.5)	(74.0)
Net (Investments in) Proceeds from Margin Deposits	38.6	27.5	(20.9)
Other Investments	(6.1)	(0.4)	-
Proceeds from Sales of Kinder Morgan Management, LLC Shares	-	254.8	-
Change in Natural Gas Storage and NGL Line Fill Inventory	(12.9)	-	-
Property Casualty Indemnifications	13.1	-	-
Sales of Other Assets Net of Removal Costs	92.2	(4.1)	40.9
Net Cash Flows Provided by (Used in) Continuing Investing Activities	(1,865.3)	(1,936.7)	53.6
Net Cash Flows Provided by (Used in) Discontinued Investing Activities	69.4	(42.0)	(60.9)
Net Cash Flows Used in Investing Activities	(1,795.9)	(1,978.7)	(7.3)

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
Kinder Morgan, Inc. and Subsidiaries

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Cash Flows from Financing Activities:			
Short-term Debt, Net	901.1	39.6	(127.9)
Bridge Facility Issued	-	2,134.7	-
Bridge Facility Retired	-	(2,129.7)	-
Long-term Debt Issued	364.1	2,400.0	-
Long-term Debt Retired	(513.3)	(505.0)	(80.0)
Cash Book Overdraft	17.9	-	-
Issuance of Shares by Kinder Morgan Management, LLC	-	-	67.6
Other Common Stock Issued	38.7	62.8	68.4
Excess Tax Benefits from Share-based Payments	18.6	-	-
Premiums Paid on Early Extinguishment of Debt	-	-	(3.0)
Short-term Advances to Unconsolidated Affiliates	(4.9)	(11.7)	(14.7)
Treasury Stock Acquired	(34.3)	(317.1)	(102.7)
Cash Dividends, Common Stock	(468.5)	(355.2)	(278.7)
Minority Interests, Distributions	(575.0)	(2.4)	(0.6)
Minority Interests, Contributions	353.8	-	-
Debt Issuance Costs	(6.0)	(14.3)	-
Other, Net	(3.5)	-	(0.1)
Net Cash Flows Provided by (Used in) Continuing Financing Activities	88.7	1,301.7	(471.7)
Net Cash Flows Provided by Discontinued Financing Activities	-	0.6	-
Net Cash Flows Provided by (Used in) Financing Activities	88.7	1,302.3	(471.7)
Effect of Exchange Rate Changes on Cash	6.6	0.3	-
Effect of Accounting Change on Cash	12.1	-	-
Cash Balance Included in Assets Held for Sale	(5.6)	-	-
Net Increase (Decrease) in Cash and Cash Equivalents	13.2	(59.9)	165.4
Cash and Cash Equivalents at Beginning of Year	116.6	176.5	11.1
Cash and Cash Equivalents at End of Year	$ 129.8	$ 116.6	$ 176.5

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Operations and Summary of Significant Accounting Policies

(A) Nature of Operations

We are one of the largest energy transportation, storage and distribution companies in North America, operating or owning an interest in approximately 43,000 miles of pipelines that transport primarily natural gas, crude oil, petroleum products and carbon dioxide; more than 155 terminals that store, transfer and handle products like gasoline and coal; and providing natural gas distribution service to over 1.1 million customers. We have both regulated and nonregulated operations. We also own the general partner interest and a significant limited partner interest in Kinder Morgan Energy Partners, L.P. ("Kinder Morgan Energy Partners"), a publicly traded pipeline limited partnership. Due to our implementation of Emerging Issues Task Force ("EITF") No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*, (see Note 1(B)), we are including Kinder Morgan Energy Partners and its consolidated subsidiaries in our consolidated financial statements effective January 1, 2006. This means that the accounts, balances and results of operations of Kinder Morgan Energy Partners and its consolidated subsidiaries are now presented on a consolidated basis with ours and those of our other consolidated subsidiaries for financial reporting purposes, instead of equity method accounting as previously reported. Our common stock is traded on the New York Stock Exchange under the ticker symbol "KMI." Unless the context requires otherwise, references to "we," "us," "our," or the "Company" are intended to mean Kinder Morgan, Inc. and its consolidated subsidiaries. Unless the context requires otherwise, references to "Kinder Morgan Energy Partners" are intended to mean Kinder Morgan Energy Partners, L.P. and its consolidated subsidiaries.

Kinder Morgan Management, LLC, referred to in this report as Kinder Morgan Management, is a publicly traded Delaware limited liability company that was formed on February 14, 2001. Kinder Morgan G.P., Inc., our indirect wholly owned subsidiary, owns all of Kinder Morgan Management's voting shares. Kinder Morgan Management's shares (other than the voting shares we hold) are traded on the New York Stock Exchange under the ticker symbol "KMR." Kinder Morgan Management, pursuant to a delegation of control agreement, has been delegated, to the fullest extent permitted under Delaware law, all of Kinder Morgan G.P., Inc.'s power and authority to manage and control the business and affairs of Kinder Morgan Energy Partners, L.P., subject to Kinder Morgan G.P., Inc.'s right to approve certain transactions.

To convert December 31, 2006 balances denominated in Canadian dollars to U.S. dollars, we used the December 31, 2006 Bank of Canada closing exchange rate of 0.8581 U.S. dollars per Canadian dollar. All dollars are U.S. dollars, except where stated otherwise. Canadian dollars are designated as C$.

On November 30, 2005, we completed the acquisition of Terasen Inc., referred to in this report as Terasen and, accordingly, Terasen's results of operations are included in our consolidated results of operations beginning on that date. Terasen is an energy transportation and utility services provider headquartered in Burnaby, British Columbia, Canada. Terasen's two core businesses are its natural gas distribution business and its petroleum pipeline business. Terasen Gas is the largest distributor of natural gas in British Columbia, serving approximately 905,000 customers at December 31, 2006. Terasen Pipelines, which we have renamed Kinder Morgan Canada, operates Trans Mountain Pipe Line, which extends from Edmonton to Vancouver and Washington State, and Corridor Pipeline, which operates between the Alberta oilsands and Edmonton. Both Trans Mountain Pipe Line and Corridor Pipeline are owned by Terasen. Kinder Morgan Canada also operates, and Terasen owns a one-third interest in, the Express System, which extends from Alberta to the U.S. Rocky Mountain region and Midwest.

On August 28, 2006, we entered into a definitive merger agreement under which investors led by Richard D. Kinder, our Chairman and Chief Executive Officer, would acquire all of our outstanding common stock for $107.50 per share in cash. Our board of directors, on the unanimous recommendation of a special committee composed entirely of independent directors, approved the agreement and recommended that our stockholders approve the merger. Our stockholders voted to approve the proposed merger agreement at a special meeting on December 19, 2006. The transaction is expected to be completed in the first or second quarter of 2007, subject to receipt of regulatory approvals, as well as the satisfaction of other customary closing conditions.

On February 26, 2007, we entered into a definitive agreement to sell Terasen Inc. This sale does not include assets of Kinder Morgan Canada (see Note 21).

(B) Basis of Presentation

Our consolidated financial statements include the accounts of Kinder Morgan, Inc. and our majority-owned subsidiaries, as well as those of Kinder Morgan Energy Partners. Except for Kinder Morgan Energy Partners, investments in 50% or less owned operations are accounted for under the equity method. These investments reported under the equity method include jointly owned operations in which we have the ability to exercise significant influence over their operating and financial policies, as was our investment in Kinder Morgan Energy Partners prior to January 1, 2006. All material intercompany transactions and balances have been eliminated. Certain prior period amounts have been reclassified to conform to the current presentation.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses. Actual results could differ from these estimates.

Due to our implementation of Emerging Issues Task Force ("EITF") No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights*, we are including Kinder Morgan Energy Partners and its consolidated subsidiaries as consolidated subsidiaries in our consolidated financial statements effective January 1, 2006. Notwithstanding the consolidation of Kinder Morgan Energy Partners and its subsidiaries into our financial statements pursuant to EITF 04-5, we are not liable for, and our assets are not available to satisfy, the obligations of Kinder Morgan Energy Partners and/or its subsidiaries and vice versa. Responsibility for payments of obligations reflected in our or Kinder Morgan Energy Partners' financial statements is a legal determination based on the entity that incurs the liability. The determination of responsibility for payment among entities in our consolidated group of subsidiaries was not impacted by the adoption of EITF 04-5.

We have prospectively applied EITF No. 04-5 using Transition Method A. The adoption of this new pronouncement has no impact on our consolidated stockholders' equity. There also is no impact on the financial covenants in our loan agreements from the implementation of EITF No. 04-5 because our $800 million credit facility was amended to exclude the effect of consolidating Kinder Morgan Energy Partners.

The adoption of this pronouncement has the effect of increasing our consolidated operating revenues and expenses and consolidated interest expense beginning January 1, 2006. However, after recording the associated minority interests in Kinder Morgan Energy Partners, our net income and earnings per common share are not affected.

(C) Accounting for Regulatory Activities

Our regulated utility operations are accounted for in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation,* which prescribes the circumstances in which the application of generally accepted accounting principles is affected by the economic effects of regulation. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or refunded to customers through the ratemaking process. The following regulatory assets and liabilities are reflected in the accompanying Consolidated Balance Sheets:

	December 31, 2006	December 31, 2005
	(In millions)	
Regulatory Assets:		
Employee Benefit Costs	$ 12.5	$ 10.6
Deferred Income Taxes	19.1	19.7
Purchased Gas Costs	-	34.6
Plant Acquisition Adjustments	-	0.5
Rate Regulation and Application Costs	6.8	2.3
Debt Issuance Costs	11.1	11.5
Foreign Currency Rate Stabilization	71.4	98.4
Changes in Fair Value of Derivatives	114.9	90.8
Deferred Development Costs on Capital Projects	20.2	16.2
Commercial Commodity Unbundling Costs	2.2	4.1
Replacement Transportation Agreement	3.2	4.1
Tax Reassessment Dispute	8.6	-
Other Regulatory Assets	17.5	17.4
Total Regulatory Assets	287.5	310.2
Regulatory Liabilities:		
Deferred Income Taxes	13.0	41.0
Purchased Gas Costs	-	13.1
Rate Regulation and Application Costs	25.3	14.6
Foreign Currency Rate Stabilization	11.4	115.2
Changes in Fair Value of Derivatives	1.1	6.1
Other Regulatory Liabilities	30.5	11.4
Total Regulatory Liabilities	81.3	201.4
Net Regulatory Assets	$ 206.2	$ 108.8

As discussed in Note 7, we entered into a definitive agreement to sell our U.S.-based retail natural gas distribution assets. Accordingly, regulatory assets of $29.4 million and regulatory liabilities of $30.4 million related to these operations have been reclassified as assets held for sale in the accompanying Consolidated Balance Sheet at December 31, 2006. As of December 31, 2006, $278.0 million of our regulatory assets and $77.3 million of our regulatory liabilities were being recovered from or refunded to customers through rates over periods ranging from 1 to 19 years.

(D) Revenue Recognition Policies

We recognize revenues as services are rendered or goods are delivered and, if applicable, title has passed. We generally sell natural gas under long-term agreements, with periodic price adjustments. In some cases, we sell natural gas under short-term agreements at prevailing market prices. In all cases, we recognize natural gas sales revenues when the natural gas is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectibility of the revenue is reasonably assured. The natural gas we market is primarily purchased gas produced by third parties, and we market this gas to power generators, local distribution companies, industrial end-users and national marketing companies. We recognize gas gathering and marketing revenues in the month of delivery based on customer nominations and generally, our natural gas marketing revenues are recorded gross, not net of cost of gas sold. Our rate-regulated retail natural gas distribution businesses bill customers on a monthly cycle billing basis. Revenues are recorded on an accrual basis, including an estimate at the end of each accounting period for gas delivered and, if applicable, for which title has passed but bills have not yet been rendered.

We provide various types of natural gas storage and transportation services to customers. The natural gas remains the property of these customers at all times. In many cases (generally described as "firm service"), the customer pays a two-part rate that includes (i) a fixed fee reserving the right to transport or store natural gas in our facilities and (ii) a per-unit rate for volumes actually transported or injected into/withdrawn from storage. The fixed-fee component of the overall rate is recognized as revenue in the period the service is provided. The per-unit charge is recognized as revenue when the volumes are delivered to the customers' agreed upon delivery point, or when the volumes are injected into/withdrawn from our storage facilities. In other cases (generally described as "interruptible service"), there is no fixed fee associated with the services because the customer accepts the possibility that service may be interrupted at our discretion in order to serve customers who have purchased firm service. In the case of interruptible service, revenue is recognized in the same manner utilized for the per-unit rate for volumes actually transported under firm service agreements.

We provide crude oil transportation services and refined petroleum products transportation and storage services to customers. Revenues are recorded when products are delivered and services have been provided and adjusted according to terms prescribed by the toll settlements with shippers and approved by regulatory authorities.

We recognize bulk terminal transfer service revenues based on volumes loaded and unloaded. We recognize liquids terminal tank rental revenue ratably over the contract period. We recognize liquids terminal throughput revenue based on volumes received and volumes delivered. Liquids terminal minimum take-or-pay revenue is recognized at the end of the contract year or contract term depending on the terms of the contract. We recognize transmix processing revenues based on volumes processed or sold, and if applicable, when title has passed. We recognize energy-related product sales revenues based on delivered quantities of product.

Revenues from the sale of oil, natural gas liquids and natural gas production are recorded using the entitlement method. Under the entitlement method, revenue is recorded when title passes based on our net interest. We record our entitled share of revenues based on entitled volumes and contracted sales prices. Since there is a ready market for oil and natural gas production, we sell the majority of our products soon after production at various locations, at which time title and risk of loss pass to the buyer. As a result, we maintain a minimum amount of product inventory in storage and the differences between actual production and sales is not significant.

(E) Earnings Per Share

Basic earnings per common share is computed based on the weighted-average number of common shares outstanding during each period. Diluted earnings per common share is computed based on the weighted-average number of common shares outstanding during each period, increased by the assumed exercise or conversion of securities (stock options, restricted stock and restricted share units are the currently the only such securities outstanding) convertible into common stock, for which the effect of conversion or exercise using the treasury stock method would be dilutive. No options were excluded from the diluted earnings per share calculation for the periods presented because none of the options would have been antidilutive. During the past several years, we have repurchased a significant number of our outstanding shares; see Note 10(E). In addition, in November 2005 we issued 12.5 million shares as partial consideration to acquire Terasen; see Note 4.

	2006	2005	2004
		(In millions)	
Weighted Average Common Shares Outstanding	133.0	123.5	123.8
Restricted Stock and Share Units	0.8	-	-
Dilutive Common Stock Options	1.2	1.1	1.1
Shares Used to Compute Diluted Earnings Per Common Share	135.0	124.6	124.9

(F) Restricted Deposits

Restricted Deposits consist of restricted funds on deposit with brokers in support of our risk management activities; see Note 12.

(G) Accounts Receivable

The caption "Accounts Receivable, Net" in the accompanying Consolidated Balance Sheets is presented net of allowances for doubtful accounts. Our policy for determining an appropriate allowance for doubtful accounts varies according to the type of business being conducted and the customers being served. An allowance for doubtful accounts is charged to expense monthly, generally using a percentage of revenue or receivables, based on a historical analysis of uncollected amounts, adjusted as necessary for changed circumstances and customer-specific information. When specific receivables are determined to be uncollectible, the reserve and receivable are relieved. In support of credit extended to certain customers, we had received prepayments of $13.0 million, $4.4 million and $3.8 million at December 31, 2006, 2005 and 2004, respectively, included in the caption "Current Liabilities: Other" in the accompanying Consolidated Balance Sheets. The following table shows the balance in the allowance for doubtful accounts and activity for the years ended December 31, 2005, 2004 and 2003.

Allowance for Doubtful Accounts

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Beginning Balance	$ 5.8	$ 3.1	$ 5.2
Additions: Charged to Cost and Expenses[1]	16.9	4.9	1.4
Deductions:			
Write-off of Uncollectible Accounts	(7.8)	(2.2)	(3.5)
Reclassification to Assets Held for Sale	(0.9)	-	-
Ending Balance	$ 14.0	$ 5.8	$ 3.1

[1] Additions in 2006 include $2.4 million associated with assets classified as held for sale at December 31, 2006, as discussed in Note 7, and $6.5 million representing allowance for doubtful accounts balances of Kinder Morgan Energy Partners as of December 31, 2005. Due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts and balances of Kinder Morgan Energy Partners are included in our consolidated results as discussed in Note 1(B). Additions in 2005 include $3.1 million acquired with Terasen. See Note 4.

(H) Inventories

	December 31,	
	2006[1]	2005
	(In millions)	
Gas in Underground Storage (Current)	$ 225.2	$ 209.6
Product Inventory	20.4	-
Materials and Supplies	29.4	18.6
	$ 275.0	$ 228.2

[1] Due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts and balances of Kinder Morgan Energy Partners are included in our consolidated results as discussed in Note 1(B).

Inventories are carried at lower of cost or market and are accounted for using the following methods, with the percent of the total dollars at December 31, 2006 shown in parentheses: average cost (76.31%) and last-in, first-out (23.69%). The excess of current cost over the reported last-in, first-out value of gas in underground storage valued under that method was $2.2 million at December 31, 2006. We also maintain gas in our underground storage facilities on behalf of certain third parties. We receive a fee from our storage service customers but do not reflect the value of their gas stored in our facilities in the accompanying Consolidated Balance Sheets.

(I) Current Assets: Other

	December 31,	
	2006[1]	2005
	(In millions)	
Assets Held for Sale - Turbines and Boilers[2]	$ 4.9	$ 23.5
Current Deferred Tax Asset	12.9	10.9
Derivatives	134.0	151.2
Prepaid Expenses	32.2	24.6
Income Tax Overpayments	6.5	10.9
Hedge Deferral	-	21.9
Other	13.7	20.2
	$ 204.2	$ 263.2

[1] Due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts and balances of Kinder Morgan Energy Partners are included in our consolidated results as discussed in Note 1(B).

[2] See Notes 5 and 6.

(J) Goodwill

Prior to the adoption of EITF No. 04-5 on January 1, 2006, we accounted for our investment in Kinder Morgan Energy Partners under the equity method. The difference between the cost of our investment and our underlying equity in the net assets of Kinder Morgan Energy Partners was recorded as equity method goodwill. Upon the adoption of EITF No. 04-5, we ceased accounting for our investment in Kinder Morgan Energy Partners under the equity method and beginning January 1, 2006, we include the accounts, balances and results of operations of Kinder Morgan Energy Partners in our consolidated financial statements. As a result, the character of the equity method goodwill was changed to goodwill arising from a business combination or acquisition, which must be allocated to one or more reporting units as of the original date of combination or acquisition.

We purchased our investment in Kinder Morgan Energy Partners in October 1999. The businesses of Kinder Morgan Energy Partners that existed at that time are presently located in the Products Pipelines – KMP, CO_2 – KMP, and Terminals – KMP segments. The equity method goodwill recharacterized as goodwill arising from an acquisition was allocated to these reporting units effective January 1, 2006 based on the respective fair value of each reporting unit at the date of our 1999 investment in Kinder Morgan Energy Partners. In addition, treating Kinder Morgan Energy Partners as our consolidated subsidiary resulted in goodwill balances residing on its books to be included within our goodwill balance. Previously these amounts were included as part of our investment in Kinder Morgan Energy Partners pursuant to the equity method.

Changes in the carrying amount of our goodwill for the years ended December 31, 2006 and 2005 are summarized as follows:

	Balance December 31, 2004	Acquisitions and Purchase Price Adjustments	Other[2]	Balance December 31, 2005
	(In millions)			
Kinder Morgan Energy Partners.	$ 893.3	$ –	$ (33.9)	$ 859.4
Power Segment	24.8	–	–	24.8
Kinder Morgan Canada Segment[3]	–	656.1	2.1	658.2
Terasen Gas Segment[3]	–	1,234.4	4.2	1,238.6
Consolidated Total	$ 918.1	$1,890.5	$ (27.6)	$ 2,781.0

	Balance December 31, 2005	KMP Goodwill Consolidated into KMI[1]	Reallocation of Equity Method Goodwill	Acquisitions and Purchase Price Adjustments	Other[2]	Balance December 31, 2006
	(In millions)					
Kinder Morgan Energy Partners	$ 859.4	$ –	$ (859.4)	$ –	$ –	$ –
Power Segment	24.8	–	–	–	–	24.8
Kinder Morgan Canada Segment[3]	658.2	–	–	–	(1.2)	657.0
Terasen Gas Segment[3]	1,238.6	–	–	100.0	(646.0)	692.6
Products Pipelines Segment	–	263.2	695.5	–	(15.3)	943.4
Natural Gas Pipelines Segment	–	288.4	–	–	–	288.4
CO_2 Segment	–	46.1	26.9	–	(0.6)	72.4
Terminals Segment	–	201.2	137.0	30.0	(3.0)	365.2
Consolidated Total	$ 2,781.0	$ 798.9	$ –	$ 130.0	$(666.1)	$ 3,043.8

1 At January 1, 2006.

2 Other adjustments include the translation of goodwill denominated in foreign currencies and reductions of the reallocation of equity method goodwill due to reductions in KMI's ownership percentage of KMP. The adjustment of $646.0 to the Terasen Gas Segment was due mainly to an impairment charge, as discussed further below.

3 Goodwill assigned to the Kinder Morgan Canada and Terasen Gas business segments is based on the purchase price allocation for our November 30, 2005 acquisition of Terasen (see Note 4).

We evaluate for the impairment of goodwill in accordance with the provisions of SFAS No. 142 *Goodwill and Other Intangible Assets*. For the investments we continue to account for under the equity method of accounting, the premium or excess cost over underlying fair value of net assets is referred to as equity method goodwill and, according to the provisions of SFAS No. 142, equity method goodwill is not subject to amortization but rather to impairment testing in accordance with APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*. As of December 31, 2006 we have reported

$138.2 million of equity method goodwill within the caption "Investments: Other" in the accompanying Consolidated Balance Sheets.

In February 2007, we entered into a definitive agreement to sell our Terasen Gas segment to Fortis, Inc. (TSX:FTS), a Canada-based company with investments in regulated distribution utilities (see Note 21). Execution of this sale agreement constituted a subsequent event of the type that, under GAAP, required us to consider the market value indicated by the definitive sales agreement in our 2006 goodwill impairment evaluation. Accordingly, based on the fair values of this reporting unit derived principally from this definitive sales agreement, an estimated goodwill impairment charge of approximately $650.5 million was recorded in the 2006 period.

(K) Other Intangibles, Net

Our intangible assets other than goodwill include lease value, contracts, customer relationships and agreements. These intangible assets have definite lives, are being amortized on a straight-line basis over their estimated useful lives, and are reported separately as "Other Intangibles, Net" in the accompanying Consolidated Balance Sheets. Due to our implementation of EITF No. 04-5, we are including Kinder Morgan Energy Partners and its consolidated subsidiaries as consolidated subsidiaries in our consolidated financial statements effective January 1, 2006. Following is information related to our intangible assets:

	December 31,	
	2006	**2005**
	(In millions)	
Lease Value:		
Gross Carrying Amount	$ 6.6	$ -
Accumulated Amortization	(1.3)	-
Net Carrying Amount	5.3	-
Contracts and Other:		
Gross Carrying Amount	260.5	29.4
Accumulated Amortization	(36.3)	(11.7)
Net Carrying Amount	224.2	17.7
Total Other Intangibles, Net	$ 229.5	$ 17.7

Amortization expense on our intangibles consisted of the following:

	Year Ended December 31,		
	2006	**2005**	**2004**
Lease Value	$ 0.1	$ -	$ -
Contracts and Other	15.0	1.5	1.5
Total Amortizations	$ 15.1	$ 1.5	$ 1.5

As of December 31, 2006, our weighted-average amortization period for our intangible assets was approximately 18.2 years. Our estimated amortization expense for these assets for each of the next five fiscal years is approximately $15.1 million, $15.1 million, $13.9 million, $13.7 million and $13.6 million, respectively.

(L) Other Investments

Due to our implementation of EITF No. 04-5, we are including Kinder Morgan Energy Partners and its consolidated subsidiaries as consolidated subsidiaries in our consolidated financial statements effective January 1, 2006.

Our significant equity investments as of December 31, 2006 consisted of:

- Express Pipeline System (33.33%);
- Plantation Pipe Line Company (51%);
- Thermo Cogeneration Partnership, L.P. and Greenhouse Holdings, LLC (Thermo Companies) (49.5%);
- West2East Pipeline LLC (51%);

- Red Cedar Gathering Company (49%);
- Customer Works LP (30%);
- Thunder Creek Gas Services, LLC (25%);
- Cortez Pipeline Company (50%);
- Horizon Pipeline Company (50%); and
- Heartland Pipeline Company (50%).

Kinder Morgan Energy Partners operates and owns an approximate 51% ownership interest in Plantation Pipe Line Company, and an affiliate of ExxonMobil owns the remaining approximate 49% interest. Each investor has an equal number of directors on Plantation's board of directors, and board approval is required for certain corporate actions that are considered participating rights. Therefore, Kinder Morgan Energy Partners does not control Plantation Pipe Line Company, and accounts for its investment under the equity method of accounting.

Our total investments consisted of the following (in millions):

	December 31,	
	2006	2005
Express Pipeline System	$ 449.7	$ 431.9
Plantation Pipe Line Company	199.6	–
Thermo Companies	153.9	147.1
Red Cedar Gathering Company	160.7	–
Customer Works LP	30.0	44.0
Thunder Creek Gas Services, LLC	37.2	–
Cortez Pipeline Company	16.2	–
Horizon Pipeline Company	16.0	17.3
Subsidiary Trusts Holding Solely Debentures of Kinder Morgan	8.6	8.6
Heartland Pipeline Company	5.7	–
All Others	7.0	0.7
Total Equity Investments	$ 1,084.6	$ 649.6

Our earnings from equity investments were as follows (in millions):

	Year Ended December 31,		
	2006	2005	2004
Cortez Pipeline Company	$ 19.2	$ –	$ –
Express Pipeline System	17.1	2.0	–
Plantation Pipe Line Company	12.8	–	–
Thermo Companies	11.3	11.5	8.6
Red Cedar Gathering Company	36.3	–	–
Customer Works LP	8.3	1.0	–
Thunder Creek Gas Services, LLC	2.5	–	–
Coyote Gas Treating, LLC	1.7	–	–
Horizon Pipeline Company	1.8	1.7	1.6
Heartland Pipeline Company	2.2	–	–
All Others	1.5	–	–
Total	$ 114.7	$ 16.2	$ 10.2
Amortization of Excess Costs	$ (5.7)	$ –	$ –

Summarized combined unaudited financial information for our significant equity investments (listed above) is reported below (in millions; amounts represent 100% of investee financial information):

	Year Ended December 31,		
	2006	2005	2004
Revenues	$ 866.7	$ 89.7	$ 56.1
Costs and Expenses	621.6	57.0	35.8
Net Income	$ 245.1	$ 32.7	$ 20.3

	December 31,	
	2006	2005
Current Assets	$ 245.2	$ 133.3
Non-current Assets	2,588.5	937.2
Current Liabilities	320.0	83.8
Non-current Liabilities	1,671.1	540.7
Partners'/Owners' Equity	842.6	446.0

Equity Investee Natural Gas Pipeline Expansion Filings

Rockies Express Pipeline-Currently Certificated Facilities

On August 9, 2005, the FERC approved the application of Rockies Express Pipeline LLC, formerly known as Entrega Gas Pipeline LLC, to construct 327 miles of pipeline facilities in two phases. For phase I (consisting of two segments), Rockies Express was granted authorization to construct and operate approximately 136 miles of pipeline extending northward from Rio Blanco County, Colorado to the Wamsutter Hub in Sweetwater County, Wyoming (segment 1), and then construct approximately 191 miles of pipeline eastward to the Cheyenne Hub in Weld County, Colorado (segment 2). Construction of segment 1 has been completed and went into interim service on February 24, 2006. Construction of segment 2 commenced in mid-summer 2006, and went into service on February 14, 2007. For Phase II, which will follow the construction of Segment 2, Rockies Express was authorized to construct three compressor stations referred to as the Meeker, Big Hole and Wamsutter compressor stations.

Rockies Express Pipeline-West Project

On May 31, 2006, in FERC Docket No. CP06-354-000, Rockies Express Pipeline LLC filed an application for authorization to construct and operate certain facilities comprising its proposed "Rockies Express-West Project." This project is the first planned segment extension of the Rockies Express' currently certificated facilities, which includes (i) a 136-mile pipeline segment currently in operation from the Meeker Hub in Colorado to the Wamsutter Hub in Wyoming, and (ii) a 191-mile segment that went into service in February 2007, from Wamsutter to the Cheyenne Hub located in Weld County, Colorado. The Rockies Express-West Project will be comprised of approximately 713 miles of 42-inch diameter pipeline extending from the Cheyenne Hub to an interconnection with Panhandle Eastern Pipe Line located in Audrain County, Missouri. The segment extension proposes to transport approximately 1.5 billion cubic feet per day of natural gas across the following five states: Wyoming, Colorado, Nebraska, Kansas and Missouri. The project will also include certain improvements to existing Rockies Express facilities located to the west of the Cheyenne Hub.

On September 21, 2006, the FERC issued a favorable preliminary determination on all non-environmental issues of the project, approving Rockies Express' application (i) to construct and operate the 713 miles of new natural gas transmission facilities from the Cheyenne Hub and (ii) to lease capacity from Questar Overthrust Pipeline Company, which will extend the Rockies Express system 140 miles west from Wamsutter to the Opal Hub in Wyoming. We expect the FERC will complete its environmental review and issue its certificate by the end of March 2007, and the project is expected to begin service in January 2008.

Rockies Express Pipeline-East Project

On June 13, 2006, the FERC agreed with Rockies Express' participation in the pre-filing process for development of the "Rockies Express-East Project." The Rockies Express-East Project will comprise approximately 635 miles of 42-inch diameter pipeline commencing from the terminus of the Rockies Express-West pipeline to a terminus near the town of Clarington in Monroe County, Ohio. The segment proposes to transport approximately 1.8 billion cubic feet per day of natural gas. On August 13, 2006, the FERC issued its notice of intent to prepare an environmental impact statement for the proposed project and hosted nine scoping meetings from September 11 through September 15, 2006 in various locations along the route. During this pre-filing process, Rockies Express has encountered opposition from certain landowners in the states of Indiana and Ohio. Rockies Express is actively participating in community outreach meetings with landowners and agencies located in these states to resolve any differences they may have with the project. Rockies Express is confident that a mutual agreement and/or understanding will be reached with these parties, and that the project is on track for a certificate application to be filed in April 2007. The application will request that a FERC order be issued by February 1, 2008 in order to meet both a December 31, 2008 project in-service date for the proposed pipeline and partial compression and a June 30, 2009 in-service date for the remaining compression.

(M) Property, Plant and Equipment

We report property, plant and equipment at its acquisition cost. We expense costs for maintenance and repairs in the period incurred. The cost of property, plant and equipment sold or retired and the related depreciation are removed from our balance sheet in the period of sale or disposition. We charge the original cost of property sold or retired to accumulated depreciation and amortization, net of salvage and cost of removal. We do not include retirement gain or loss in income except in the case of significant retirements or sales. Gains and losses on minor system sales, excluding land, are recorded to the appropriate accumulated depreciation reserve. Gains and losses for operating systems sales and land sales are booked to income or expense accounts in accordance with regulatory accounting guidelines.

As discussed under (H) preceding, we maintain natural gas in underground storage as part of our inventory. This component of our inventory represents the portion of gas stored in an underground storage facility generally known as "working gas," and represents an estimate of the portion of gas in these facilities available for routine injection and withdrawal to meet demand. In addition to this working gas, underground gas storage reservoirs contain injected gas which is not routinely cycled but, instead, serves the function of maintaining the necessary pressure to allow efficient operation of the facility. This gas, generally known as "cushion gas," is divided into the categories of "recoverable cushion gas" and "unrecoverable cushion gas," based on an engineering analysis of whether the gas can be economically removed from the storage facility at any point during its life. The portion of the cushion gas that is determined to be unrecoverable is considered to be a permanent part of the facility itself (thus, part of our Property, Plant & Equipment balance) and is depreciated over the facility's estimated useful life. The portion of the cushion gas that is determined to be recoverable is also considered a component of the facility but is not depreciated because it is expected to ultimately be recovered and sold.

Depreciation on our long-lived assets is computed principally based on the straight-line method over their estimated useful lives. Depreciation of certain non-regulated equipment is recorded using the declining balance method. The ranges of estimated useful lives used in depreciating assets are as follows:

Property Type	Range of Estimated Useful Lives of Assets
	(In years)
Natural Gas and CO_2 Pipelines	24 to 68 (Transmission assets: average 55)
Petroleum Pipelines	17 to 55
Retail Natural Gas Distribution	5 to 66
Pipeline and Terminal Station Equipment	15 to 40
Storage Facilities	40 to 45
Power Generation	4 to 30
General and Other	3 to 56

Our oil and gas producing activities are accounted for under the successful efforts method of accounting. Under this method costs that are incurred to acquire leasehold and subsequent development costs are capitalized. Costs that are associated with the drilling of successful exploration wells are capitalized if proved reserves are found. Costs associated with the drilling of exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of certain non-producing leasehold costs are expensed as incurred. The capitalized costs of our producing oil and gas properties are depreciated and depleted by the units-of-production method. Other miscellaneous property, plant and equipment are depreciated over the estimated useful lives of the asset.

A gain on the sale of property, plant and equipment used in our oil and gas producing activities is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received. A gain on an asset disposal is recognized in income in the period that the sale is closed. A loss on the sale of property, plant and equipment is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received or the maket value if the asset is being held for sale. A loss is recognized when the asset is sold or when the net cost of an asset held for sale is greater than the market value of the asset.

In addition, we engage in enhanced recovery techniques in which carbon dioxide is injected into certain producing oil reservoirs. In some cases, the acquisition cost of the carbon dioxide associated with enhanced recovery is capitalized as part of our development costs when it is injected. The acquisition cost associated with pressure maintenance operations for reservoir management is expensed when it is injected. When carbon dioxide is recovered in conjunction with oil production, it is extracted and re-injected, and all of the associated costs are expensed as incurred. Proved developed reserves are used in computing units of production rates for drilling and development costs, and total proved reserves are used for depletion of leasehold costs. The units-of-production rate is determined by field.

We evaluate the impairment of our long-lived assets in accordance with Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 requires that long-lived assets that are to be disposed of by sale be measured at the lower of book value or fair value less the cost to sell. We review for the impairment of long-lived assets whenever events or changes in circumstances indicate that our carrying amount of an asset may not be recoverable. We would recognize an impairment loss when estimated future cash flows expected to result from our use of the asset and its eventual disposition is less than its carrying amount.

We evaluate our oil and gas producing properties for impairment of value on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure, using undiscounted future cash flows based on total proved and risk-adjusted probable and possible reserves. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future cash flows based on total proved and risk-adjusted probable and possible reserves or, if available, comparable market values. Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment.

(N) Asset Retirement Obligations

We adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, ("SFAS No. 143") effective January 1, 2003. This statement changed the financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated retirement costs. The 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. In March 2005, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations—an interpretation of FASB Statement No. 143* ("FIN 47"). This Interpretation clarifies that the term "conditional asset retirement obligation" as used in SFAS No. 143, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. The implementation of FIN 47 will not change the application of the guidance implemented under SFAS No. 143 in relation to our facts and circumstances. The impact of the adoption of SFAS No. 143 on us is discussed below by segment.

We have included $1.4 million of our total asset retirement obligations as of December 31, 2006 in the caption "Current Liabilities: Other," $0.4 million related to our discontinued retail natural gas distribution operations in the caption "Liabilities Held for Sale, Non-Current" and the remaining $50.7 million in the caption "Other Liabilities and Deferred Credits: Other" in the accompanying Consolidated Balance Sheet. A reconciliation of the changes in our accumulated asset retirement obligations for each of the years ended December 31, 2006 and 2005 is as follows:

	Year Ended December 31,	
	2006	**2005**
	(In millions)	
Balance at Beginning of Period	$ 3.2	$ 3.3
KMP ARO Consolidated into KMI[1]	43.2	-
Liabilities Incurred	6.8	-
Liabilities Settled	(3.2)	(0.2)
Accretion Expense	2.5	0.1
Balance at End of Period	$ 52.5	$ 3.2

[1] Represents asset retirement obligation balances of Kinder Morgan Energy Partners as of December 31, 2005. Due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts and balances of Kinder Morgan Energy Partners are included in our consolidated results as discussed in Note 1(B).

In general, NGPL's system is composed of underground piping, compressor stations and associated facilities, natural gas storage facilities and certain other facilities and equipment. Except as discussed following, we have no plans to abandon any of these facilities, the majority of which have been providing utility service for many years, making it impossible to determine the timing of any potential retirement expenditures. Notwithstanding our current intentions, in general, if we were to cease utility operations in total or in any particular area, we would be permitted to abandon the underground piping in place, but would have to remove our surface facilities from land belonging to our customers or others. We would generally have no obligations for removal or remediation with respect to equipment and facilities, such as compressor stations, located on land we own.

NGPL has various condensate drip tanks located throughout the system, storage wells located within the storage fields, laterals no longer integral to the overall mainline transmission system, compressor stations which are no longer active, and other miscellaneous facilities, all of which have been officially abandoned. For these facilities, it is possible to reasonably estimate the timing of the payment of obligations associated with their retirement. The recognition of these obligations has resulted in a liability and associated asset of approximately $1.8 million as of December 31, 2006, representing the present value of those future obligations for which we are able to make reasonable estimations of the current fair value due to, as discussed above, our ability to estimate the timing of the incurrence of the expenditures. The remainder of NGPL's asset retirement obligations have not been recorded due to our inability, as discussed above, to reasonably estimate when they will be settled in cash. We will record liabilities for these obligations when we are able to reasonably estimate their fair value.

In the CO_2 – KMP business segment, we are required to plug and abandon oil and gas wells that have been removed from service and to remove our surface wellhead equipment and compressors. As of December 31, 2006, we have recognized asset retirement obligations relating to these requirements at existing sites within the CO_2 – KMP segment in the aggregate amount of $47.2 million.

In the Natural Gas Pipelines – KMP business segment, if we were to cease providing utility services, we would be required to remove surface facilities from land belonging to our customers and others. The Texas intrastate natural gas pipeline group has various condensate drip tanks and separators located throughout its natural gas pipeline systems, as well as one inactive gas processing plant, various laterals and gathering systems which are no longer integral to the overall mainline transmission systems, and asbestos-coated underground pipe which is being abandoned and retired. The Kinder Morgan Interstate Gas Transmission system has compressor stations which are no longer active and other miscellaneous facilities, all of which have been officially abandoned. We believe we can reasonably estimate both the time and costs associated with the retirement of these facilities. As of December 31, 2006, we have recognized asset retirement obligations relating to the businesses within the Natural Gas Pipelines – KMP segment in the aggregate amount of $3.1 million.

We acquired the assets of Kinder Morgan Canada effective November 30, 2005 as part of our acquisition of Terasen. The underground piping, compressor stations and associated facilities and equipment operated by Kinder Morgan Canada have been in service for many years. There are no plans to abandon or otherwise replace or remove any portion of these assets other than through the normal maintenance of the system. We have concluded that while the legal determination of obligation may exist to some extent, the corresponding asset retirement dates are indeterminable, and therefore sufficient information does not exist to estimate the fair value of any retirement obligation in relation to these assets and no asset retirement obligation has been recognized. A liability will be recognized for asset retirement obligations, if any, when the fair value of any such obligation is determinable.

We acquired the assets of Terasen Gas effective November 30, 2005 as part of our acquisition of Terasen. The assets of Terasen Gas have been in service for many years and there are no plans to abandon or otherwise replace or remove any portion of these assets other than through the normal maintenance of the system. We have concluded that while the legal determination of obligation may exist to some extent, the corresponding asset retirement dates are indeterminable, and therefore sufficient information does not exist to estimate the fair value of any retirement obligation in relation to these assets and no asset retirement obligation has been recognized. A liability will be recognized for asset retirement obligations related to these assets, if any, when the fair value of any such obligation is determinable.

The facilities utilized in our power generation activities fall into two general categories: those that we own and those that we do not own. With respect to those facilities that we do not own but either operate or maintain a preferred interest in, principally the Jackson, Michigan power plant, we have no obligation for any asset retirement obligation that may exist or arise. With respect to the Colorado power generation assets that we do own (located on land that we also own), we have no asset retirement obligation with respect to those facilities, and no direct responsibility for assets in which we own an interest accounted for under the equity method of accounting. Thus, our power generation activities do not give rise to any asset retirement obligations.

(O) Gas Imbalances and Gas Purchase Contracts

We value gas imbalances due to or due from interconnecting pipelines at the lower of cost or market. Gas imbalances represent the difference between customer nominations and actual gas receipts from and gas deliveries to our interconnecting pipelines and shippers under various operational balancing and shipper imbalance agreements. Natural gas imbalances are settled in cash or made up in-kind subject to the pipelines' various terms. Terasen Gas and Terasen Gas (Vancouver Island) Inc. ("TGVI") have entered into gas purchase contracts, which represent future purchase obligations. Gas purchase contract commitments are based on market prices that vary with gas commodity indices. Our discontinued U.S.-based natural gas distribution business is obligated under certain gas purchase contracts, dating from 1973, to purchase natural gas at fixed and escalating prices from a certain field in Montana. This take obligation, which continues for the life of the field, is based on production from specific wells and, thus, varies from year to year. See Note 15 for gas purchase contract commitments.

(P) Interest Expense

"Interest Expense, Net" as presented in the accompanying Consolidated Statements of Operations is net of capitalized interest, as shown following.

	Year Ended December 31,		
	2006	**2005**	**2004**
		(In millions)	
Interest Expense	$ 790.9	$ 167.5	$ 125.8
Capitalized Interest[1]	(25.6)	(1.2)	(0.5)
Interest Expense, Net	765.3	166.3	125.3
Interest Expense – Deferrable Interest Debentures	21.9	21.9	21.9
Interest Expense – Capital Securities	8.7	0.7	-
Total Interest Expense	$ 795.9	$ 188.9	$ 147.2

[1] Includes the debt component of the allowance for funds used during construction for our regulated utility operations, which are accounted for in accordance with the provisions of SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation.*

The increase in net interest expense for the twelve months ended December 31, 2006 is primarily due to (i) $333.4 million relating to the inclusion of the results of operations of Kinder Morgan Energy Partners in our consolidated results as required by EITF No. 04-5 which, as discussed in Note 1(B), became effective and was implemented on January 1, 2006 and (ii) a $250.2 million increase resulting from the inclusion of eleven months additional net interest expense in 2006 relating to the acquisition of Terasen which was effective November 30, 2005 (see Note 4).

(Q) Other, Net

"Other, Net" as presented in the accompanying Consolidated Statements of Operations includes a $22.5 million net loss on currency transactions in 2006 . Included in "Other, Net" in 2005 is a $78.5 million net gain on sales of Kinder Morgan Management shares that we owned, which transactions are discussed in Note 5, and a $15.0 million charge for our charitable contribution to the Kinder Morgan Foundation.

(R) Cash Flow Information

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. "Other, Net," presented as a component of "Net Cash Flows From Operating Activities" in the accompanying Consolidated Statements of Cash Flows includes, among other things, non-cash charges and credits to income including amortization of deferred revenue and amortization of gains and losses realized on the termination of interest rate swap agreements; see Note 12.

ADDITIONAL CASH FLOW INFORMATION

Changes in Working Capital Items
(Net of Effects of Acquisitions and Sales)
Increase (Decrease) in Cash and Cash Equivalents

	Year Ended December 31,		
	2006	**2005**	**2004**
		(In millions)	
Accounts Receivable	$ 292.3	$ (73.3)	$ 6.8
Materials and Supplies Inventory	1.7	0.6	0.5
Other Current Assets	106.2	(50.6)	(16.0)
Accounts Payable	(325.0)	(2.9)	(7.7)
Income Tax Benefits from Employee Benefit Plans	-	22.0	19.4
Other Current Liabilities	(10.8)	33.8	38.2
	$ 64.4	$ (70.4)	$ 41.2

Supplemental Disclosures of Cash Flow Information

	Year Ended December 31,		
	2006	**2005**	**2004**
		(In millions)	
Cash Paid for:			
Interest (Net of Amount Capitalized)	$ 731.6	$ 184.0	$ 161.6
Income Taxes Paid (Net of Refunds)[1]	$ 314.9	$ 204.0	$ 144.1

[1] Income taxes paid includes taxes paid related to prior periods.

As discussed in Note 1(B), due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts, balances and results of operations of Kinder Morgan Energy Partners are included in our consolidated financial statements and we no longer apply the equity method of accounting to our investment in Kinder Morgan Energy Partners. Therefore, we have included Kinder Morgan Energy Partners' cash and cash equivalents at December 31, 2005 of $12.1 million as an "Effect of Accounting Change on Cash" in the accompanying Consolidated Statement of Cash Flows.

In March 2006, Kinder Morgan Energy Partners made a $17.0 million contribution of net assets to its investment in Coyote Gulch.

In December 2006, Kinder Morgan Energy Partners contributed 34,627 common units, representing approximately $1.7 million of value, as partial consideration for the acquisition of Devco USA L.L.C.

During 2006, we acquired $6.1 million of assets by the assumption of liabilities.

On November 30, 2005, we contributed 12.5 million shares of our common stock, representing approximately $1.1 billion of value, as partial consideration for the acquisition of Terasen Inc. The fair values of non-cash assets acquired and liabilities assumed were $7.4 billion and $4.2 billion, respectively. See Note 4.

A portion of the consideration received in the November 2004 contribution of TransColorado Gas Transmission Company was Kinder Morgan Energy Partners common units, see Note 5.

Distributions received by our Kinder Morgan Management, LLC subsidiary from its investment in i-units of Kinder Morgan Energy Partners are in the form of additional i-units, while distributions made by Kinder Morgan Management, LLC to its shareholders are in the form of additional Kinder Morgan Management, LLC shares, see Note 3.

As discussed in Note 14 following, during 2006, 2005 and 2004, we made non-cash grants of restricted shares of common stock.

(S) Stock-Based Compensation

Effective January 1, 2006, we implemented Statement of Financial Accounting Standards ("SFAS") No. 123R (revised 2004), *Share-Based Payment* ("SFAS No. 123R"). This Statement amends SFAS No. 123, *Accounting for Stock-Based Compensation* ("SFAS No. 123"), and requires companies to expense the value of employee stock options and similar awards. Because we have used the fair-value method of accounting for stock-based compensation for pro forma disclosure under SFAS No. 123, we are applying SFAS No. 123R using the modified prospective method. Under this transition method, compensation cost is recognized on or after the required effective date for the portion of outstanding awards for which the requisite service has not yet been rendered, based on the grant-date fair value of those awards calculated under SFAS No. 123 for pro forma disclosures. Note 14 contains information regarding our common stock option, restricted stock, and stock purchase plans.

	Effect of Applying Statement No. 123(R) Year Ended December 31, 2006
	(In millions, except per share amounts)
Income from Continuing Operations Before Income Taxes	$ (5.0)
Income from Continuing Operations	$ (3.2)
Net Income	$ (3.2)
Basic Earnings Per Common Share	$ (0.02)
Diluted Earnings Per Common Share	$ (0.03)
Net Cash Flows Provided by Operating Activities	$ (18.6)
Net Cash Flows Provided by Financing Activities	$ 18.6

For the years ended December 31, 2005 and 2004, had compensation cost for these plans been determined using the fair-value-based method, net income and diluted earnings per share would have been reduced to the pro forma amounts shown in the table below.

	Year Ended December 31,	
	2005	2004
	(In millions except per share amounts)	
Net Income As Reported	$ 554.6	$ 522.1
Add: Stock-based employee compensation expense included in reported Net Income, net of related tax effects	5.2	3.2
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(12.3)	(15.8)
Pro Forma Net Income	$ 547.5	$ 509.5
Basic Earnings Per Common Share:		
As Reported	$ 4.49	$ 4.22
Pro Forma	$ 4.43	$ 4.12
Diluted Earnings Per Common Share:		
As Reported	$ 4.45	$ 4.18
Pro Forma	$ 4.39	$ 4.08

(T) Transactions with Related Parties

Due to our implementation of EITF No. 04-5, we are including Kinder Morgan Energy Partners and its consolidated subsidiaries as consolidated subsidiaries in our consolidated financial statements effective January 1, 2006.

Plantation Pipe Line Company

Kinder Morgan Energy Partners owns a 51.17% equity interest in Plantation Pipe Line Company ("Plantation"). An affiliate of ExxonMobil owns the remaining 48.83% interest. In July 2004, Plantation repaid a $10 million note outstanding and $175 million in outstanding commercial paper borrowings with funds of $190 million borrowed from its owners. Kinder Morgan Energy Partners loaned Plantation $97.2 million, which corresponds to its 51.17% ownership interest, in exchange for a seven-year note receivable bearing interest at the rate of 4.72% per annum. The note provides for semiannual payments of principal and interest on December 31 and June 30 each year beginning on December 31, 2004 based on a 25-year amortization schedule, with a final principal payment of $157.9 million due July 20, 2011. Kinder Morgan Energy Partners funded its loan of $97.2 million with borrowings under its commercial paper program. An affiliate of ExxonMobil owns the remaining 48.83% equity interest in Plantation and funded the remaining $92.8 million on similar terms.

In 2006, Plantation paid to Kinder Morgan Energy Partners $1.1 million in principal amount under the note, and as of December 31, 2006, the principal amount receivable from this note was $93.1 million. We included $3.4 million of this balance within "Accounts, Notes and Interest Receivable, Net: Related Parties" on our consolidated balance sheet as of December 31, 2006, and we included the remaining $89.7 million balance as "Notes Receivable – Related Parties."

Coyote Gas Treating, LLC

Coyote Gas Treating, LLC is a joint venture that was organized in December 1996. It is referred to as Coyote Gulch in this report. The sole asset owned by Coyote Gulch is a 250 million cubic feet per day natural gas treating facility located in La Plata County, Colorado. Prior to the contribution of Kinder Morgan Energy Partners' ownership interest in Coyote Gulch to Red Cedar Gathering on September 1, 2006, discussed below, Kinder Morgan Energy Partners was the managing partner and owned a 50% equity interest in Coyote Gulch.

In June 2001, Coyote Gulch repaid the $34.2 million in outstanding borrowings under its 364-day credit facility with funds borrowed from its owners. Kinder Morgan Energy Partners loaned Coyote Gulch $17.1 million, which corresponds to its 50% ownership interest, in exchange for a one-year note receivable bearing interest payable monthly at London Interbank Offered Rate ("LIBOR") plus a margin of 0.875%. On June 30, 2002 and June 30, 2003, the note was extended for one year. On June 30, 2004, the term of the note was made month-to-month. In 2005, Kinder Morgan Energy Partners reduced its investment in the note by $0.1 million to account for its share of investee losses in excess of the carrying value of its equity investment in Coyote Gulch.

In March 2006, Enterprise Field Services LLC ("Enterprise") and Kinder Morgan Energy Partners agreed to transfer Coyote Gulch's notes payable to Enterprise and Kinder Morgan Energy Partners to members' equity. Accordingly, Kinder Morgan Energy Partners contributed the principal amount of $17.0 million related to its note receivable to its equity investment in Coyote Gulch.

In the third quarter of 2006, the Southern Ute Indian Tribe acquired the remaining 50% ownership interest in Coyote Gulch from Enterprise. The acquisition was made effective March 1, 2006. On September 1, 2006, Kinder Morgan Energy Partners and the Southern Ute Tribe agreed to transfer all of the members' equity in Coyote Gulch to the members' equity of Red Cedar Gathering, a joint venture organized in August 1994 and referred to in this report as Red Cedar. Red Cedar owns and operates natural gas gathering, compression and treating facilities in the Ignacio Blanco Field in La Plata County, Colorado, and is owned 49% by Kinder Morgan Energy Partners and 51% by the Southern Ute Tribe. Under the terms of a five-year operating lease agreement that became effective January 1, 2002, Red Cedar also operates the gas treating facility owned by Coyote Gulch and is responsible for all operating and maintenance expenses and capital costs.

Accordingly, on September 1, 2006, Kinder Morgan Energy Partners and the Southern Ute Tribe contributed the value of their respective 50% ownership interests in Coyote Gulch to Red Cedar, and as a result, Coyote Gulch became a wholly owned subsidiary of Red Cedar. The value of Kinder Morgan Energy Partners' 50% equity contribution from Coyote Gulch to Red Cedar on September 1, 2006 was $16.7 million, and this amount remains included within "Investments: Other" in our accompanying Consolidated Balance Sheet as of December 31, 2006.

The "Accounts Receivable, Related Parties" balances shown in the accompanying Consolidated Balance Sheets primarily represent balances with Plantation Pipeline Company at December 31, 2006 and Kinder Morgan Energy Partners at December 31, 2005. Balances with Kinder Morgan Energy partners at December 31, 2005 arose from performing administrative functions for them, including cash management, hedging activities, centralized payroll and employee benefits services and expenses incurred in performing as general partner of Kinder Morgan Energy Partners.

Related-party operating revenues are included in the accompanying Consolidated Statements of Operations as follows:

	Year Ended December 31,		
	2006	**2005**	**2004**
		(In millions)	
Natural Gas Transportation and Storage	$ 6.1	$ 4.4	$ 4.5
Natural Gas Sales	-	9.4	5.5
Other Revenues	-	1.6	1.6
Total Related-party Operating Revenues	$ 6.1	$ 15.4	$ 11.6

During 2006, related-party operating revenues were primarily attributable to Horizon Pipeline Company and Plantation Pipeline Company. During 2005 and 2004, when we accounted for Kinder Morgan Energy Partners under the equity method, related-party revenues were primarily attributable to Horizon Pipeline Company and entities owned by Kinder Morgan Energy Partners.

The caption "Gas Purchases and Other Costs of Sales" in the accompanying Consolidated Statements of Operations includes related-party costs totaling $1.5 million, $25.3 million and $29.1 million for the years 2006, 2005 and 2004, respectively. Related-party costs during 2005 and 2004, when we accounted for Kinder Morgan Energy Partners under the equity method, primarily related to natural gas transportation and storage services and natural gas provided by entities owned by Kinder Morgan Energy Partners.

Effective November 1, 2004, we contributed TransColorado Gas Transmission Company to Kinder Morgan Energy Partners. See Note 5.

(U) Accounting for Risk Management Activities

We utilize energy derivatives for the purpose of mitigating our risk resulting from fluctuations in the market price of natural gas, natural gas liquids, crude oil and associated transportation. We also utilize interest rate swap agreements to mitigate our exposure to changes in the fair value of our fixed rate debt agreements and cross-currency interest rate swap agreements to mitigate foreign currency risk from our investments in businesses owned and operated outside the United States. Our accounting policy for these activities is in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* and related pronouncements. This policy is described in detail in Note 12.

(V) Income Taxes

Income tax expense is recorded based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance for the amount of any tax benefit we do not expect to be realized. Note 9 contains information about our income taxes, including the components of our income tax provision and the composition of our deferred income tax assets and liabilities.

(W) Accounting for Legal Costs

In general, we expense legal costs as incurred. When we identify significant specific litigation that is expected to continue for a significant period of time and require substantial expenditures, we identify a range of probable costs expected to be required to litigate the matter to a conclusion or reach an acceptable settlement. If no amount within this range is a better estimate than any other amount, we record a liability equal to the low end of the range. Any such liability recorded is revised as better information becomes available.

(X) Accounting for Minority Interests

Due to our implementation of EITF No. 04-5, we are including Kinder Morgan Energy Partners and its consolidated subsidiaries as consolidated subsidiaries in our consolidated financial statements effective January 1, 2006.

The caption "Minority Interests in Equity of Subsidiaries" in our Consolidated Balance Sheets is comprised of the following balances:

	December 31,	
	2006	**2005**
	(In millions)	
Kinder Morgan Energy Partners	$ 1,727.7	$ -
Kinder Morgan Management, LLC	1,328.4	1,221.7
Triton Power	25.9	21.8
Other	13.5	3.8
	$ 3,095.5	$ 1,247.3

During 2006, Kinder Morgan Energy Partners paid distributions of $3.23 per common unit for the year ended December 31, 2006, of which $465.7 million was paid to the public holders (represented in minority interests) of Kinder Morgan Energy Partners' common units. On January 17, 2007, Kinder Morgan Energy Partners declared a quarterly distribution of $0.83 per common unit for the quarterly period ended December 31, 2006. The distribution was paid on February 14, 2007, to unitholders of record as of January 31, 2007.

(Y) Foreign Currency Translation

We translate our Canadian dollar denominated Terasen financial statements into United States dollars using the current rate method of foreign currency translation. Under this method, assets and liabilities are translated at the rate of exchange in effect at the balance sheet date, revenue and expense items are translated at average rates of exchange for the period, and the exchange gains and losses arising on the translation of the financial statements are reflected as a separate component of Accumulated Other Comprehensive Income in the accompanying Consolidated Balance Sheet.

Foreign currency transaction gains or losses, other than hedges of net investments in foreign companies, are included in results of operations. In 2006, we recorded net pre-tax losses of $22.5 million from foreign currency transactions and swaps. See Note 12 for information regarding our hedges of net investments in foreign companies.

2. Investment in Kinder Morgan Energy Partners, L.P.

We own the general partner of, and a significant limited partner interest in, Kinder Morgan Energy Partners. At December 31, 2006, we owned, directly, and indirectly in the form of i-units corresponding to the number of shares of Kinder Morgan Management we owned, approximately 29.97 million limited partner units of Kinder Morgan Energy Partners. These units, which consist of 14.36 million common units, 5.31 million Class B units and 10.30 million i-units, represent approximately 13.0% of the total limited partner interests of Kinder Mo rgan Energy Partners. See Note 3 for additional information regarding Kinder Morgan Management, LLC and Kinder Morgan Energy Partners' i-units. In addition, we are the sole stockholder of the general partner of Kinder Morgan Energy Partners, which holds an effective 2% interest in Kinder Morgan Energy Partners and its operating partnerships. Together, our limited partner and general partner interests represented approximately 14.7% of Kinder Morgan Energy Partners' total equity interests at December 31, 2006.

Following is summarized financial information for Kinder Morgan Energy Partners for 2005 and 2004, when we accounted for Kinder Morgan Energy Partners under the equity method. As discussed in Note 1(B), due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts, balances and results of operations of Kinder Morgan Energy Partners are included in our consolidated financial statements and we no longer apply the equity method of accounting to our investment in Kinder Morgan Energy Partners. Additional information regarding Kinder Morgan Energy Partners' results of operations and financial position are contained in its 2006 Annual Report on Form 10-K.

	Summarized Income Statement Information Year Ended December 31,	
	2005	2004
	(In millions)	
Operating Revenues	$ 9,787.1	$ 7,932.9
Operating Expenses	8,773.6	6,958.9
Operating Income	$ 1,013.5	$ 974.0
Net Income	$ 812.2	$ 831.6

	Summarized Balance Sheet Information As of December 31,2005
	(In millions)
Current Assets	$ 1,215.2
Noncurrent Assets	$ 10,708.2
Current Liabilities	$ 1,808.9
Noncurrent Liabilities	$ 6,458.5
Minority Interest	$ 42.3

3. Kinder Morgan Management, LLC

Kinder Morgan Management, LLC, referred to in this report as Kinder Morgan Management, is a publicly traded Delaware limited liability company that was formed on February 14, 200 1. Kinder Morgan G.P., Inc., our indirect wholly owned subsidiary, owns all of Kinder Morgan Management's voting shares. Kinder Morgan Management's shares (other than the voting shares we hold) are traded on the New York Stock Exchange under the ticker symbol "KMR". Kinder Morgan Management, pursuant to a delegation of control agreement, has been delegated, to the fullest extent permitted under Delaware law, all of Kinder Morgan G.P., Inc.'s power and authority to manage and control the business and affairs of Kinder Morgan Energy Partners, L.P., subject to Kinder Morgan G.P., Inc.'s right to approve certain transactions.

On November 14, 2006, Kinder Morgan Management made a distribution of 0.018981 of its shares per outstanding share (1,160,520 total shares) to shareholders of record as of October 31, 2006, based on the $0.81 per common unit distribution declared by Kinder Morgan Energy Partners. On February 14, 2007, Kinder Morgan Management made a distribution of 0.016919 of its shares per outstanding share (1,054,082 total shares) to shareholders of record as of January 31, 2007, based on the $0.83 per common unit distribution declared by Kinder Morgan Energy Partners. These distributions are paid in the form of additional shares or fractions thereof calculated by dividing the Kinder Morgan Energy Partners' cash distribution per common unit by the average market price of a Kinder Morgan Management share determined for a ten-trading day period ending on the trading day immediately prior to the ex-dividend date for the shares. Kinder Morgan Management has paid share distributions totaling 4,383,303, 3,760,732 and 3,500,512 shares in the years ended December 31, 2006, 2005 and 2004, respectively.

On November 10, 2004, Kinder Morgan Management closed the issuance and sale of 1,300,000 of its listed shares in a limited registered offering. None of the shares from the offering were purchased by Kinder Morgan, Inc. Kinder Morgan Management used the net proceeds of approximately $52.6 million from the offering to buy additional i-units from Kinder Morgan Energy Partners.

On March 25, 2004, Kinder Morgan Management closed the issuance and sale of 360,664 of its listed shares in a limited registered offering. None of the shares from the offering were purchased by Kinder Morgan, Inc. Kinder Morgan Management used the net proceeds of approximately $14.9 million from the offering to buy additional i-units from Kinder Morgan Energy Partners.

At December 31, 2006, we owned 10.3 million Kinder Morgan Management shares representing 16.5% of Kinder Morgan Management's outstanding shares.

4. Business Combinations

The following acquisitions were accounted for under the purchase method and the assets acquired and liabilities assumed were recorded at their estimated fair market values as of the acquisition date. The preliminary allocation of assets (and any liabilities assumed) may be adjusted to reflect the final determined amounts during a period of time following the acquisition. Although the time that is required to identify and measure the fair value of the assets acquired and the liabilities assumed in a business combination will vary with circumstances, generally our allocation period ends when we no longer are waiting for information that is known to be available or obtainable. The results of operations from these acquisitions are included in our consolidated financial statements from the acquisition date.

Terasen

On November 30, 2005, we completed the acquisition of Terasen and, accordingly, Terasen's results of operations are included in our consolidated results of operations beginning on that date. Terasen is an energy transportation and utility services provider headquartered in Burnaby, British Columbia, Canada. Terasen's two core businesses are its natural gas distribution business and its petroleum pipeline business. Terasen Gas is the largest distributor of natural gas in British Columbia, serving approximately 905,000 customers at December 31, 2006. Terasen Pipelines, which we have renamed Kinder Morgan Canada, operates Trans Mountain Pipe Line, which extends from Edmonton to Vancouver and Washington State, and Corridor Pipeline, which extends from the Alberta oilsands to Edmonton. Both Trans Mountain Pipe Line and Corridor Pipeline are owned by Terasen. Kinder Morgan Canada also operates, and Terasen owns a one-third interest in, the Express System, which extends from Alberta to the U.S. Rocky Mountain region and Midwest.

Pursuant to the Combination Agreement among us, one of our wholly owned subsidiaries, and Terasen, Terasen shareholders were able to elect, for each Terasen share held, either (i) C$35.75 in cash, (ii) 0.3331 shares of Kinder Morgan common stock, or (iii) C$23.25 in cash plus 0.1165 shares of Kinder Morgan common stock. In the aggregate, we issued approximately 12.48 million shares of Kinder Morgan common stock and paid approximately C$2.49 billion (US$2.13 billion) in cash to Terasen securityholders.

The acquisition was accounted for as a purchase and, accordingly, the assets acquired and liabilities assumed are recorded at their respective estimated fair market values as of the acquisition date. The calculation of the total purchase price and the allocation of that purchase price to the assets acquired and liabilities assumed based on their estimated fair market values is shown following.

The Total Purchase Price Consisted of the Following:	(In millions)
Total Market Value of Kinder Morgan, Inc. Common Shares Issued.............	$ 1,146.8
Cash Paid – U.S. Dollar Equivalent	2,134.3
Transaction Fees..	15.7
Total Purchase Price..	$ 3,296.8

The Allocation of the Purchase Price is as Follows:	(In millions)
Current Assets	$ 812.7
Goodwill	1,990.4
Investments	504.8
Property, Plant and Equipment	3,592.7
Deferred Charges and Other Assets	602.4
Current Liabilities	(1,517.8)
Deferred Income Taxes	(667.2)
Other Deferred Credits	(264.5)
Long-term Debt	(1,756.7)
	$ 3,296.8

The final allocation of the purchase price resulted in the recording of $1.99 billion of total goodwill, which we do not expect to be deductible for income tax purposes. During 2006, the allocation to goodwill increased by approximately $100 million, primarily related to revisions in the estimated fair value of regulated assets. There are a number of factors contributing to the total purchase price that resulted in our recognition of goodwill from this transaction, including: a stable portfolio of natural gas distribution assets; potential future deregulation or unbundling of natural gas distribution services; expected increases in Canadian oilsands production and worldwide oil demand and the potential for expansion projects with attractive overall returns combined with our ability to capitalize on those projects due to our expertise in developing and operating energy-related assets. The allocation of goodwill to reporting segments is as follows:

Allocation of Goodwill:	(In millions)
Terasen Gas	$ 1,334.3
Kinder Morgan Canada	656.1
	$ 1,990.4

On February 26, 2007, we entered into a definitive agreement to sell Terasen Inc. to Fortis Inc. (see Notes 6 and 21). This sale does not include the assets of Kinder Morgan Canada.

Entrega Gas Pipeline LLC

Effective February 23, 2006, Rockies Express Pipeline LLC acquired Entrega Gas Pipeline LLC from EnCana Corporation for $244.6 million in cash. West2East Pipeline LLC is a limited liability company and is the sole owner of Rockies Express Pipeline LLC. Kinder Morgan Energy Partners contributed 66 2/3% of the consideration for this purchase, which corresponded to its percentage ownership of West2East Pipeline LLC at that time. At the time of acquisition, Sempra Energy held the remaining 33 1/3% ownership interest and contributed this same proportional amount of the total consideration.

With regard to Rockies Express Pipeline LLC's acquisition of Entrega Gas Pipeline LLC, the allocation of the purchase price to assets acquired and liabilities assumed was as follows (in millions):

Purchase Price:	
Cash Paid, Including Transaction Costs	$ 244.6
Liabilities Assumed	–
Total Purchase Price	$ 244.6
Allocation of Purchase Price:	
Current Assets	$ –
Property, Plant and Equipment	244.6
Deferred Charges and Other Assets	–
	$ 244.6

On the acquisition date, Entrega Gas Pipeline LLC owned the Entrega Pipeline, an interstate natural gas pipeline that will, when fully constructed, consist of two segments: (i) a 136-mile, 36-inch diameter pipeline that extends from the Meeker Hub in Rio Blanco County, Colorado to the Wamsutter Hub in Sweetwater County, Wyoming and (ii) a 191-mile, 42-inch diameter pipeline that extends from the Wamsutter Hub to the Cheyenne Hub in Weld County, Colorado, where it will ultimately connect with the Rockies Express Pipeline, an interstate natural gas pipeline that is currently being developed by Rockies Express Pipeline LLC. The acquired operations are included as part of the Natural Gas Pipelines – KMP business segment.

In the first quarter of 2006, EnCana Corporation completed construction of the pipeline segment that extends from the Meeker Hub to the Wamsutter Hub, and interim service began on that portion of the pipeline on February 24, 2006. Under the terms of the purchase and sale agreement, Rockies Express Pipeline LLC will construct the segment that extends from the Wamsutter Hub to the Cheyenne Hub. Construction on this pipeline segment began in the second quarter of 2006, and both pipeline segments were placed into service on February 14, 2007.

In April 2006, Rockies Express Pipeline LLC merged with and into Entrega Gas Pipeline LLC, and the surviving entity was renamed Rockies Express Pipeline LLC. Going forward, the entire pipeline system (including the lines currently being developed) will be known as the Rockies Express Pipeline. The combined 1,663-mile pipeline system will be one of the largest natural gas pipelines ever constructed in North America. The approximately $4.4 billion project will have the capability to transport 1.8 billion cubic feet per day of natural gas, and binding firm commitments have been secured for virtually all of the pipeline capacity.

On June 30, 2006, ConocoPhillips exercised its option to acquire a 25% ownership interest in West2East Pipeline LLC (and its subsidiary Rockies Express Pipeline LLC). On that date, a 24% ownership interest was transferred to ConocoPhillips, and an additional 1% interest will be transferred once construction of the entire project is completed. Through Kinder Morgan Energy Partners' subsidiary, Kinder Morgan W2E Pipeline LLC, Kinder Morgan Energy Partners will continue to operate the project but its ownership interest decreased to 51% of the equity in the project (down from 66 2/3%). Sempra's ownership interest in West2East Pipeline LLC decreased to 25% (down from 33 1/3%). When construction of the entire project is completed, Kinder Morgan Energy Partners' ownership interest will be reduced to 50% at which time the capital accounts of West2East Pipeline LLC will be trued up to reflect its 50% economics in the project. We do not anticipate any additional changes in the ownership structure of the Rockies Express Pipeline project.

West2East Pipeline LLC qualifies as a variable interest entity as defined by Financial Accounting Standards Board Interpretation No. 46 (Revised December 2003), *Consolidation of Variable Interest Entities-An Interpretation of ARB No. 51* ("FIN 46R"), due to the fact that the total equity at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by any parties, including equity holders. Furthermore, following ConocoPhillips' acquisition of its ownership interest in West2East Pipeline LLC on June 30, 2006, Kinder Morgan Energy Partners receives 50% of the economics of the Rockies Express project on an ongoing basis, and thus, effective June 30, 2006, Kinder Morgan Energy Partners was no longer considered the primary beneficiary of this entity as defined by FIN 46R. Accordingly, on that date, we made the change in accounting for the investment in West2East Pipeline LLC from full consolidation to the equity method following the decrease in Kinder Morgan Energy Partners' ownership percentage.

Under the equity method, the costs of the investment in West2East Pipeline LLC will be recorded within the "Investments: Other" caption on our consolidated balance sheet and as changes in the net assets of West2East Pipeline LLC occur (for example, earnings and dividends), we will recognize our proportional share of that change in the "Investments: Other" account. We will also record our proportional share of any accumulated other comprehensive income or loss within the "Accumulated Other Comprehensive Loss" caption on our consolidated balance sheet.

Summary financial information as of December 31, 2006, for West2East Pipeline LLC, which is accounted for under the equity method, is as follows (in millions of dollars; amounts represent 100% of investee information):

Balance Sheet	December 31, 2006
Current Assets	$ 3.5
Non-current Assets	$ 847.0
Current Liabilities	$ 68.5
Non-Current Liabilities	$ 790.1
Accumulated Other Comprehensive Income (Loss)	$ (8.1)

In addition, Kinder Morgan Energy Partners has guaranteed its proportionate share of West2East Pipeline LLC's debt borrowings under a $2 billion credit facility entered into by Rockies Express Pipeline LLC.

<u>April 2006 Oil and Gas Properties</u>

On April 5, 2006, Kinder Morgan Production Company L.P. purchased various oil and gas properties from Journey Acquisition – I, L.P. and Journey 2000, L.P. for an aggregate consideration of approximately $63.9 million, consisting of $60.3 million in cash and $3.6 million in assumed liabilities. The acquisition was effective March 1, 2006. However, Kinder Morgan Energy Partners divested certain acquired properties that are not considered candidates for carbon dioxide enhanced oil recovery, thus reducing the total investment. Kinder Morgan Energy Partners received proceeds of approximately $27.1 million from the sale of these properties.

The properties are primarily located in the Permian Basin area of West Texas and New Mexico, produce approximately 425 barrels of oil equivalent per day, and include some fields with potential for enhanced oil recovery development near our current carbon dioxide operations. The acquired operations are included as part of the CO2 – KMP business segment. Currently, Kinder Morgan Energy Partners is performing technical evaluations to confirm the carbon dioxide enhanced oil recovery potential and generate definitive plans to develop this potential, if proven to be economic.

The allocation of the purchase price to assets acquired and liabilities assumed was as follows (in millions):

Purchase Price:		
Cash Paid, Including Transaction Costs	$	60.3
Liabilities Assumed		3.6
Total Purchase Price	$	63.9
Allocation of Purchase Price:		
Current Assets	$	0.2
Property, Plant and Equipment		63.7
	$	63.9

April 2006 Terminal Assets

In April 2006, Kinder Morgan Energy Partners acquired terminal assets and operations from A&L Trucking, L.P. and U.S. Development Group in three separate transactions for an aggregate consideration of approximately $61.9 million, consisting of $61.6 million in cash and $0.3 million in assumed liabilities.

The first transaction included the acquisition of equipment and infrastructure on the Houston Ship Channel that loads and stores steel products. The acquired assets complement Kinder Morgan Energy Partners' nearby bulk terminal facility purchased from General Stevedores, L.P. in July 2005. The second acquisition included the purchase of a rail terminal at the Port of Houston that handles both bulk and liquids products. The rail terminal complements Kinder Morgan Energy Partners' existing Texas petroleum coke terminal operations and maximizes the value of its existing deepwater terminal by providing customers with both rail and vessel transportation options for bulk products. Thirdly, Kinder Morgan Energy Partners acquired the entire membership interest of Lomita Rail Terminal LLC, a limited liability company that owns a high-volume rail ethanol terminal in Carson, California. The terminal serves approximately 80% of the southern California demand for reformulated fuel blend ethanol with expandable offloading/distribution capacity, and the acquisition expanded Kinder Morgan Energy Partners' existing rail transloading operations. All of the acquired assets are included in the Terminals – KMP business segment.

The allocation of the purchase price to assets acquired and liabilities assumed was as follows (in millions):

Purchase Price:		
Cash Paid, Including Transaction Costs	$	61.6
Liabilities Assumed		0.3
Total Purchase Price	$	61.9
Allocation of Purchase Price:		
Current Assets	$	0.5
Property, Plant and Equipment		43.6
Goodwill		17.8
	$	61.9

The $17.8 million of goodwill was assigned to the Terminals – KMP business segment and the entire amount is expected to be deductible for tax purposes.

November 2006 Transload Services, LLC

Effective November 20, 2006, Kinder Morgan Energy Partners acquired all of the membership interests of Transload Services, LLC from Lanigan Holdings, LLC for an aggregate consideration of approximately $16.8 million, consisting of $15.4 million in cash, an obligation to pay $0.9 million currently held as security for the collection of certain accounts receivable and for the perfection of certain real property title rights, and $0.5 million of assumed liabilities. Transload Services, LLC is a leading provider of innovative, high quality material handling and steel processing services, operating 14 steel-related terminal facilities located in the Chicago metropolitan area and various cities in the United States. Its operations include transloading services, steel fabricating and processing, warehousing and distribution, and project staging. Specializing in steel processing and handling, Transload Services can inventory product, schedule shipments and provide customers cost-effective modes of transportation. The combined operations include over 92 acres of outside storage and 445,000 square feet of covered storage that offers customers environmentally controlled warehouses with indoor rail and truck loading facilities for handling temperature and humidity sensitive products. The acquired assets are included in the Terminals – KMP business segment, and the acquisition further expanded and diversified Kinder Morgan Energy Partners' existing terminals' materials services (rail transloading) operations.

As of December 31, 2006, the preliminary allocation of the purchase price to assets acquired and liabilities assumed was as follows (in millions):

Purchase Price:		
Cash Paid, Including Transaction Costs	$	15.4
Payment Obligation		0.9
Liabilities Assumed		0.5
Total Purchase Price	$	16.8
Allocation of Purchase Price:		
Current Assets	$	1.6
Property, Plant and Equipment		6.6
Goodwill		8.6
	$	16.8

The $8.6 million of goodwill was assigned to the Terminals – KMP business segment, and the entire amount is expected to be deductible for tax purposes. Kinder Morgan Energy Partners believes this acquisition resulted in the recognition of goodwill primarily due to the fact that it establishes a business presence in several key markets, taking advantage of the non-residential and highway construction demand for steel that contributed to the fair value of acquired identifiable net assets and liabilities exceeding our acquisition price - in the aggregate, these factors represented goodwill. Our allocation of the purchase price to assets acquired and liabilities assumed is preliminary, pending final determination of working capital balances at the time of acquisition. Kinder Morgan Energy Partners expects these final working capital adjustments to be made in the first quarter of 2007.

<u>December 2006 Devco USA L.L.C.</u>

Effective December 1, 2006, Kinder Morgan Energy Partners acquired all of the membership interests in Devco USA L.L.C., an Oklahoma limited liability company, for an aggregate consideration of approximately $7.3 million, consisting of $4.8 million in cash, $1.6 million in common units, and $0.9 million of assumed liabilities. The primary asset acquired was a technology based identifiable intangible asset, a proprietary process that transforms molten sulfur into premium solid formed pellets that are environmentally friendly, easy to handle and store, and safe to transport. The process was developed internally by Devco's engineers and employees. Devco, a Tulsa, Oklahoma based company, has more than 20 years of sulfur handling expertise and Kinder Morgan Energy Partners believes the acquisition and subsequent application of this acquired technology complements its existing dry-bulk terminal operations. Kinder Morgan Energy Partners allocated $6.5 million of the total purchase price to the value of this intangible asset, which is included as part of the Terminals – KMP business segment.

The allocation of the purchase price to assets acquired and liabilities assumed was as follows (in millions):

Purchase Price:		
Cash Paid, Including Transaction Costs	$	4.8
Issuance of Common Units		1.6
Liabilities Assumed		0.9
Total Purchase Price	$	7.3
Allocation of Purchase Price:		
Current Assets	$	0.8
Deferred Charges and Other Assets		6.5
	$	7.3

<u>December 2006 Roanoke, Virginia Products Terminal</u>

Effective December 15, 2006, Kinder Morgan Energy Partners acquired a refined petroleum products terminal located in Roanoke, Virginia from Motiva Enterprises, LLC for approximately $6.4 million in cash. The terminal has storage capacity of approximately 180,000 barrels per day for refined petroleum products like gasoline and diesel fuel. The terminal is served exclusively by the Plantation Pipeline and Motiva has entered into a long-term contract to use the terminal. The acquisition complemented the other refined products terminals Kinder Morgan Energy Partners owns in the southeast region of the United States, and the acquired terminal is included as part of the Products Pipelines business segment.

The allocation of the purchase price to assets acquired and liabilities assumed was as follows (in millions):

Purchase Price:		
Cash Paid, Including Transaction Costs	$	6.4
Liabilities Assumed		-
Total Purchase Price	$	6.4
Allocation of Purchase Price:		
Property, Plant and Equipment	$	6.4
	$	6.4

Pro Forma Information

The following summarized unaudited pro forma consolidated income statement information for the years ended December 31, 2006 and 2005, assumes that all of the acquisitions we have made and joint ventures we have entered into between January 1, 2005 and December 31, 2006, including the ones listed above, had occurred as of the beginning of the period presented. We have prepared these unaudited pro forma financial results for comparative purposes only. These unaudited pro forma financial results may not be indicative of the results that would have occurred if we had completed these acquisitions and joint ventures as of the beginning of the period presented or the results that will be attained in the future.

	Year Ended December 31,	
	2006	**2005**
	(In millions, except per share amounts)	
Operating Revenues	$ 11,871.7	$ 2,591.2
Income from Continuing Operations	$ 700.2	$ 610.1
Net Income	$ 723.3	$ 633.1
Diluted Earnings Per Common Share	$ 5.36	$ 4.65
Common Shares Used in Computing Diluted Earnings Per Share	135.0	136.1

Acquisitions Subsequent to December 31, 2006

On January 15, 2007, Kinder Morgan Energy Partners announced that it had entered into an agreement with affiliates of BP to increase its ownership interest in the Cochin pipeline system to 100%. Kinder Morgan Energy Partners purchased its original undivided 32.5% ownership interest in the Cochin pipeline system in November 2000, and currently owns a 49.8% ownership interest. BP Canada Energy Company owns the remaining 50.2% ownership interest and is the operator of the pipeline. The agreement is subject to due diligence, regulatory clearance and other standard closing conditions. The transaction is expected to close in the first quarter of 2007, and upon closing, Kinder Morgan Energy Partners will become the operator of the pipeline.

5. Investments and Sales

In December 2006, Kinder Morgan Energy Partners issued 34,627 common units as partial consideration for the acquisition of Devco USA L.L.C. This transaction reduced our percentage ownership of Kinder Morgan Energy Partners (at the time of the transaction) from approximately 14.7324% to approximately 14.7305% and had the associated effects of increasing our investment in the net assets of Kinder Morgan Energy Partners by $80,000 and reducing our (i) equity method goodwill in Kinder Morgan Energy Partners by $110,000, (ii) associated accumulated deferred income taxes by $11,411 and (iii) paid-in capital by $18,589. In addition, in December 2006, in order to maintain our 1% general partner interest in Kinder Morgan Energy Partners' operating partnerships, we made a contribution of $16,837.

In December 2006, we sold power generation equipment for $13.3 million (net of marketing fees). We recognized a pre-tax gain of $1.2 million associated with this sale. The book value of the remaining surplus power generation equipment available for sale at December 31, 2006 was $4.3 million. During the first quarter of 2006, we sold power generation equipment for $7.5 million (net of marketing fees). We recognized a pre-tax gain of $1.5 million associated with this sale. This equipment was a portion of the equipment that became surplus as a result of our decision to exit the power development business.

In August 2006, Kinder Morgan Energy Partners issued 5.75 million common units in a public offering at a price of $44.80 per common unit, receiving total net proceeds (after underwriting discount) of $248.0 million. This transaction reduced our percentage ownership of Kinder Morgan Energy Partners (at the time of the transaction) from approximately 15.0% to approximately 14.7% and had the associated effects of increasing our investment in the net assets of Kinder Morgan Energy Partners by $11.2 million and reducing our (i) equity method goodwill in Kinder Morgan Energy Partners by $18.8 million, (ii) associated accumulated deferred income taxes by $2.8 million and (iii) paid-in capital by $4.7 million. In addition, in August 2006, in order to maintain our 1% general partner interest in Kinder Morgan Energy Partners' operating partnerships, we made a contribution of approximately $2.5 million.

Effective April 1, 2006, Kinder Morgan Energy Partners sold its Douglas natural gas gathering system and its Painter Unit fractionation facility to Momentum Energy Group, LLC for approximately $42.5 million in cash. Kinder Morgan Energy Partners' investment in net assets, including all transaction related accruals, was approximately $24.5 million, most of which represented property, plant and equipment, and Kinder Morgan Energy Partners recognized approximately $18.0 million of gain on the sale of these net assets. Kinder Morgan Energy Partners used the proceeds from these asset sales to reduce the outstanding balance on its commercial paper borrowings.

The Douglas gathering system is comprised of approximately 1,500 miles of 4-inch to 16-inch diameter pipe that gathers approximately 26 million cubic feet per day of natural gas from approximately 650 active receipt points. Gathered volumes are processed at Kinder Morgan Energy Partners' Douglas plant (which Kinder Morgan Energy Partners retained), located in Douglas, Wyoming. As part of the transaction, Kinder Morgan Energy Partners executed a long-term processing agreement with Momentum Energy Group, LLC, which dedicates volumes from the Douglas gathering system to Kinder Morgan Energy Partners' Douglas processing plant. The Painter Unit, located near Evanston, Wyoming, consists of a natural gas processing plant and fractionator, a nitrogen rejection unit, a natural gas liquids terminal, and interconnecting pipelines with truck and rail loading facilities. Prior to the sale, Kinder Morgan Energy Partners leased the plant to BP, which operates the fractionator and the associated Millis terminal and storage facilities for its own account.

Additionally, with regard to the natural gas operating activities of Kinder Morgan Energy Partners' Douglas gathering system, Kinder Morgan Energy Partners utilized certain derivative financial contracts to offset its exposure to fluctuating expected future cash flows caused by periodic changes in the price of natural gas and natural gas liquids. According to the provisions of current accounting principles, changes in the fair value of derivative contracts that are designated and effective as cash flow hedges of forecasted transactions are reported in other comprehensive income (not net income) and recognized directly in equity (included within accumulated other comprehensive income/(loss)). Amounts deferred in this way are reclassified to net income in the same period in which the forecast transactions are recognized in net income. However, if a hedged transaction is no longer expected to occur by the end of the originally specified time period, because, for example, the asset generating the hedged transaction is disposed of prior to the occurrence of the transaction, then the net cumulative gain or loss recognized in equity should be transferred to net income in the current period.

Accordingly, upon the sale of Kinder Morgan Energy Partners' Douglas gathering system, Kinder Morgan Energy Partners reclassified a net loss of $2.9 million on those derivative contracts that effectively hedged uncertain future cash flows associated with forecasted Douglas gathering transactions from "Accumulated Other Comprehensive Loss" into net income. We included the net amount of the gain, $15.1 million, within the caption "Operating Costs and Expenses: Other Expenses (Income)" in our accompanying consolidated statements of operations for the year ended December 31, 2006.

On December 27, 2005, we sold 1,670,000 Kinder Morgan Management shares that we owned for approximately $74.2 million. We recognized a pre-tax gain of $22.2 million associated with this sale.

On November 10, 2005, we sold 279,631 Kinder Morgan Management shares that we owned for approximately $13.0 million. We recognized a pre-tax gain of $4.2 million associated with this sale.

On November 8, 2005, Kinder Morgan Energy Partners issued 2.6 million common units in a public offering at a price of $51.75 per common unit, receiving total net proceeds (after underwriting discount) of $130.1 million. We did not acquire any of these common units. This transaction reduced our percentage ownership of Kinder Morgan Energy Partners (at the time of the transactions) from approximately 16.2% to approximately 16.0% and had the associated effects of increasing our investment in the net assets of Kinder Morgan Energy Partners by $6.7 million and reducing our (i) equity method goodwill in Kinder Morgan Energy Partners by $9.0 million, (ii) associated accumulated deferred income taxes by $0.9 million and (iii) paid-in capital by $1.4 million. In addition, in November 2005, in order to maintain our 1% general partner interest in Kinder Morgan Energy Partners' operating partnerships, we made a contribution of approximately $1.3 million.

On October 31, 2005, we sold 1,586,965 Kinder Morgan Management shares that we owned for approximately $75.1 million. We recognized a pre-tax gain of $25.6 million associated with this sale.

In August and September 2005, Kinder Morgan Energy Partners issued 5.75 million common units in a public offering at a price of $51.25 per common unit, receiving total net proceeds (after underwriting discount) of $283.6 million. We did not acquire any of these common units. In August 2005, Kinder Morgan Energy Partners issued 64,412 common units as partial consideration for the acquisition of General Stevedores, L.P. These issuances, collectively, reduced our percentage ownership of Kinder Morgan Energy Partners (at the time of the transactions) from approximately 17.3% to approximately 16.9% and had the associated effects of increasing our investment in the net assets of Kinder Morgan Energy Partners by $18.0 million and reducing our (i) equity method goodwill in Kinder Morgan Energy Partners by $21.2 million, (ii) associated accumulated deferred income taxes by $1.2 million and (iii) paid-in capital by $1.9 million. In addition, in August 2005, in order to maintain our 1% general partner interest in Kinder Morgan Energy Partners' operating partnerships, we made a contribution of approximately $2.6 million.

On June 1, 2005, we sold 1,717,033 Kinder Morgan Management shares that we owned for approximately $75.0 million. We recognized a pre-tax gain of $22.0 million associated with this sale.

In April 2005, Kinder Morgan Energy Partners issued 957,656 common units as partial consideration for the acquisition of seven bulk terminal operations. This transaction reduced our percentage ownership of Kinder Morgan Energy Partners (at the time of the transaction) from approximately 18.13% to approximately 18.06% and had the associated effects of increasing our investment in the net assets of Kinder Morgan Energy Partners by $2.9 million and reducing our (i) equity method goodwill in Kinder Morgan Energy Partners by $3.6 million, (ii) associated accumulated deferred income taxes by $0.3 million and (iii) paid-in capital by $0.4 million. In addition, in April 2005, in order to maintain our 1% general partner interest in Kinder Morgan Energy Partners' operating partnerships, we made a contribution of approximately $0.6 million.

On January 31, 2005, we sold 413,516 Kinder Morgan Management shares that we owned for approximately $17.5 million. We recognized a pre-tax gain of $4.5 million associated with this sale.

On November 10, 2004, Kinder Morgan Energy Partners issued 5.5 million common units in a public offering at a price of $46.00 per common unit, less commissions and underwriting expenses. On December 8, 2004, Kinder Morgan Energy Partners issued an additional 575,000 common units upon the exercise by the underwriters of an over-allotment option. After commissions and underwriting expenses, Kinder Morgan Energy Partners received net proceeds of $268.3 million. We did not acquire any of these common units. Kinder Morgan Energy Partners also issued 1.3 million i-units in conjunction with a Kinder Morgan Management limited registered offering of its shares in November 2004. We did not acquire any of the Kinder Morgan Management shares in this offering. These transactions reduced our percentage ownership of Kinder Morgan Energy Partners (at the time of the transactions) from approximately 18.5% to approximately 17.9%. In accordance with our policy, we treat transactions such as these as "capital" transactions and, accordingly, no gain or loss was recorded. Instead, the impact of the difference between the sales proceeds and our underlying book basis had the effect of increasing our investment in the net assets of Kinder Morgan Energy Partners by $15.8 million and reducing our (i) equity method goodwill in Kinder Morgan Energy Partners by $29.6 million, (ii) paid-in capital by $8.6 million and (iii) associated accumulated deferred income taxes by $5.3 million. In addition, in order to maintain our 1% general partner interest in Kinder Morgan Energy Partners' operating partnerships, we made a contribution of approximately $3.9 million.

Effective November 1, 2004, we contributed TransColorado Gas Transmission Company to Kinder Morgan Energy Partners for total consideration of $275.0 million (approximately $210.8 million in cash and 1.4 million Kinder Morgan Energy Partners common units). In conjunction with this contribution, we recorded a pre-tax loss of $0.6 million.

Since 1998, we have had an investment in a 76 megawatt gas-fired power generation facility located in Greeley, Colorado. We recorded impairments of this investment during 2005 and 2004; See Note 6.

In July 2004, we sold our remaining surplus LM 6000 gas-fired turbine for consideration of $8.3 million (net of marketing fees), which consideration consisted of $2.0 million in cash, a note receivable of $6.5 million and a payable for marketing fees of $0.2 million. This note receivable has been collected as of December 31, 2005. In April 2004, we sold two LM6000 gas-fired turbines for $16.5 million (net of marketing fees), which consideration consisted of $2.4 million in cash, a note receivable of $14.5 million and a note payable for marketing fees of $0.4 million. During September 2004, the remaining balance of this receivable was collected. In June 2004, we sold two LM6000 turbines and two boilers to Kinder Morgan Production Company, L.P., a subsidiary of Kinder Morgan Energy Partners, for their estimated fair market value of $21.1 million, which we received in cash. This equipment was a portion of the equipment that became surplus as a result of our decision to exit the power development business. We recorded a pre-tax gain of $3.6 million in conjunction with these sales. Recognizing the effects of changes in technology and the limited improvement of the general economies of the electric generation industry, we determined that the carrying values of our remaining turbines and associated equipment should be reduced. In the fourth quarter of 2004, we reduced the carrying value of these assets by $7.4 million. The book value of the remaining surplus power generation equipment available for sale at December 31, 2005 was $23.5 million.

On March 25, 2004, Kinder Morgan Management closed the issuance and sale of 360,664 listed shares in a limited registered offering. None of the shares from the offering were purchased by us. Kinder Morgan Management used the net proceeds of approximately $14.9 million from the offering to buy 360,664 additional i-units from Kinder Morgan Energy Partners. This issuance of i-units reduced our percentage ownership of Kinder Morgan Energy Partners (at the time of the transaction) from approximately 18.54% to approximately 18.51% and had the associated effects of increasing our investment in the net assets of Kinder Morgan Energy Partners by $0.7 million and reducing our (i) equity method goodwill in Kinder Morgan Energy Partners by $1.5 million, (ii) paid-in capital by $0.5 million and (iii) associated accumulated deferred income taxes by $0.3 million. In addition, in order to maintain our 1% general partner interest in Kinder Morgan Energy Partners' operating partnerships, we made a contribution of approximately $0.2 million.

In February 2004, Kinder Morgan Energy Partners issued 5.3 million common units in a public offering at a price of $46.80 per common unit, receiving total net proceeds (after underwriting discount) of $237.8 million. We did not acquire any of these common units. This transaction reduced our percentage ownership of Kinder Morgan Energy Partners (at the time of the transaction) from approximately 19.0% to approximately 18.5% and had the associated effects of increasing our investment in the net assets of Kinder Morgan Energy Partners by $12.9 million and reducing our (i) equity method goodwill in Kinder Morgan Energy Partners by $23.1 million, (ii) associated accumulated deferred income taxes by $3.9 million and (iii) paid-in capital by $6.3 million. In addition, in February 2004, in order to maintain our 1% general partner interest in Kinder Morgan Energy Partners' operating partnerships, we made a contribution of approximately $2.4 million.

6. Impairment of Assets

In February 2007, we entered into a definitive agreement to sell Terasen Inc. to Fortis, Inc. (TSX:FTS), a Canada-based company with investments in regulated distribution utilities, see Note 21. Execution of this sale agreement constituted a subsequent event of the type that, under Generally Accepted Accounting Principles, required us to consider the market value indicated by the definitive sales agreement in our 2006 goodwill impairment evaluation. Accordingly, based on the fair values of these reporting unit(s) derived principally from this definitive sales agreement, an estimated goodwill impairment charge of approximately $650.5 million was recorded in the 2006 period.

Since 1998, we have had an investment in a 76 megawatt gas-fired power generation facility located in Greeley, Colorado. We became concerned with the value of this investment as a result of several recent circumstances including the expiration of a gas purchase contract, the amendment of the associated power purchase agreement and uncertainties surrounding the management of this facility, which has changed ownership twice in recent years. These ownership changes made it difficult for us to obtain information necessary to forecast the future of this asset. During the fourth quarter of 2004, we concluded that we had sufficient information to determine that our investment had been impaired and, accordingly, reduced our carrying value by $26.1 million. We wrote off the remaining carrying value of this investment ($6.5 million) in the fourth quarter of 2005 as it became clear that this facility could no longer operate profitably in the high gas price environment resulting from hurricane damage to Gulf Coast production.

During 2004 and 2006, we sold our turbines and a portion of our certain associated equipment (see Note 5). Recognizing the effects of technology and the limited improvement of the general economies of the electric generation industry, we determined that the carrying values of our remaining turbines and associated equipment should be reduced. In the fourth quarter of 2004, we reduced the asset values by $7.4 million. In the fourth quarter of 2006, we reduced the asset values by an additional $1.2 million when it was determined that certain equipment could no longer be sold as complete units since the manufacturer, who had agreed to fabricate and provide site specific external materials upon the sale of the units, had declared bankruptcy. We are continuing our efforts to sell the remaining inventory of surplus turbines and associated equipment, which had a carrying value of $4.3 million at December 31, 2006.

7. Discontinued Operations

In August 2006, we entered into a definitive agreement with a subsidiary of General Electric Company ("GE") to sell our U.S.-based retail natural gas distribution and related operations for $710 million plus working capital. Pending regulatory approvals, we expect this transaction to close by the end of the first quarter of 2007. In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* the financial results of these operations have been reclassified to discontinued operations for all periods presented. The assets and liabilities of these operations are included in our Consolidated Balance Sheet at December 31, 2006 in the captions "Current Assets: Assets Held for Sale", "Assets Held for Sale, Non-current", "Current Liabilities: Liabilities Held for Sale" and "Liabilities Held for Sale, Non-current." No such reclassification of the assets and liabilities of the U.S.-based retail natural gas distribution business has been made to the Consolidated Balance Sheet at December 31, 2005. Summarized financial results and financial position information of these operations is as follows:

	Year Ended December 31,		
	2006	2005	2004
		(In millions)	
Operating Revenues	$ 361.6	$ 331.2	$ 287.2
Operating Expenses	(319.2)	(282.9)	(230.3)
Other Income and Expenses, Net	(7.6)	(10.7)	(7.9)
Earnings (Loss) Before Income Taxes	34.8	37.6	49.0
Income Taxes	(10.3)	(15.4)	(18.7)
Earnings (Loss) from Discontinued Operations	$ 24.5	$ 22.2	$ 30.3

	At December 31, 2006
	(In millions)
Current Assets	$ 87.9
Property, Plant and Equipment, Net	414.8
Other Assets	7.5
Total Assets	$ 510.2
Current Liabilities	$ 78.3
Other Liabilities and Deferred Credits	7.9
Total Liabilities	$ 86.2

Our U.S.-based retail natural gas distribution operations obtain natural gas transportation and storage services and purchase natural gas from and provides transportation and storage services, natural gas and product sales and other gas supply services to our Natural Gas Pipelines – KMP business segment and we expect these transactions to continue to a similar extent following the close of the disposal transaction. The intercompany revenues and expenses of our ongoing operations for products and services sold to and purchased from our discontinued operations that have been eliminated in our Consolidated Statements of Operations were $19.3 million and $3.4 million, respectively, for the twelve months ended December 31, 2006. Revenues and expenses for these products and services were not eliminated in 2005 due to the fact that we did not include Kinder Morgan Energy Partners in our consolidated operating results until the implementation of EITF 04-5, effective January 1, 2006 (see Note 1(B)). In addition, following the close of the disposal transaction, we expect to receive fees from GE to provide certain administrative functions for a limited period of time and for the lease of office space. We will not have any significant continuing involvement in or retain any ownership interest in these operations and, therefore, the continuing cash flows discussed above are not considered direct cash flows of the disposal group.

In conjunction with the acquisition of Terasen on November 30, 2005 (see Note 4), we adopted and implemented plans to discontinue Terasen Water and Utility Services and its affiliates, which offers water, wastewater and utility services, primarily in Western Canada. In December of 2005, we recorded losses of $0.7 million (net of tax benefits of $0.3 million) to reflect the one month operating results of the water and utility business segment since its inclusion in our Consolidated Statement of Operations. During the second quarter of 2006, Terasen completed the sale of Terasen Water and Utility Services to a group led by CAI Capital Management Co. and including the existing management team of Terasen Water and Utility Services for approximately $118 million (C$133 million). The sale does not include CustomerWorks LP, a 30% joint venture with Enbridge Inc. No gain or loss was recognized from the sale of the water and utility segment. Incremental losses of $0.7 million (net of tax benefits of $0.4 million) were recorded in the six months ended June 30, 2006 reflecting the operating results of the water and utility business segment during 2006 until its sale.

During 1999, we adopted and implemented a plan to discontinue a number of lines of business. During 2000, we essentially completed the disposition of these discontinued operations. During 2006, incremental losses of approximately $0.6 million (net of tax benefits of $0.3 million) were recorded to increase previously recorded liabilities to reflect updated estimates. During 2005, a gain of $3.2 million (net of tax of $1.9 million) was recorded to reflect the settlement of previously recorded liabilities. During 2004, incremental losses of approximately $6.4 million (net of tax benefits of $3.8 million) were recorded to increase previously recorded liabilities to reflect updated estimates.

The cash flows attributable to discontinued operations are included in our Consolidated Statements of Cash Flows for the years ended December 31, 2006, 2005 and 2004 in the captions "Net Cash Flows Provided by Discontinued Operations", "Net Cash Flows Provided by (Used in) Discontinued Investing Activities" and "Net Cash Flows Provided by Discontinued Financing Activities".

8. Property, Plant and Equipment

Classes and Depreciation

As of December 31, 2006 and 2005, investments in property, plant and equipment are as follows:

	December 31, 2006	December 31, 2005
	(In millions)	
Kinder Morgan, Inc.:		
Natural Gas Pipelines	$ 4,320.4	$ 4,708.9
Storage Facilities	1,035.2	696.0
Retail Natural Gas Distribution	-	378.6
Electric Generation	37.9	37.9
General and Other	149.0	216.6
Terasen:		
Natural Gas Pipelines	968.8	841.3
Petroleum Pipelines	1,104.9	1,099.9
Retail Natural Gas Distribution	1,180.7	1,427.7
General and Other	381.0	220.3
Kinder Morgan Energy Partners:		
Natural Gas, Liquids and Carbon Dioxide Pipelines	4,559.7	-
Pipeline and Terminals Station Equipment	4,508.8	-
General and Other	850.8	-
Accumulated Amortization, Depreciation and Depletion	(2,306.3)	(728.7)
	$ 16,790.9	$ 8,898.5
Land	273.9	38.6
Natural Gas, Liquids (including Line Fill) and Transmix Processing	615.9	457.6
Construction Work in Process	1,158.9	150.9
Total Consolidated Property, Plant and Equipment	$ 18,839.6	$ 9,545.6

Casualty Gain

Several of Kinder Morgan Energy Partners' terminal assets were affected by Hurricanes Katrina and Rita in the fall of 2005. To account for property damage, repair expense was recognized as incurred. In addition, the net book value of assets that were damaged or destroyed by the hurricanes was removed from the books and offset with indemnity proceeds received (and receivable in the future). Any proceeds received in excess of the net book value of assets was recorded as a casualty gain.

In the fourth quarter of 2006, Kinder Morgan Energy Partners reached settlements with its insurance carriers on all property damage claims related to the 2005 hurricanes and recognized a casualty gain of $15.2 million, excluding repair and clean-up expenses. Kinder Morgan Energy Partners collected $13.1 million in proceeds during 2006, which is included in the caption "Property Casualty Indemnifications" in our accompanying Consolidated Statement of Cash Flows, and signed proofs of loss totaling $8.0 million, which proceeds were received in January 2007. With the settlement of these claims, all hurricane property damage claims are now closed; however, Kinder Morgan Energy Partners will recognize approximately $2.0 million of casualty gain in the first quarter of 2007 based upon the final determination of the book value of their damaged or destroyed fixed assets.

9. Income Taxes

The components of income (loss) before income taxes from continuing operations are as follows:

	Year Ended December 31, 2006	2005	2004
		(In millions)	
United States	$ 917.9	$ 844.8	$ 706.2
Foreign	(595.1)	30.6	-
Total	$ 322.8	$ 875.4	$ 706.2

Components of the income tax provision applicable to continuing operations for federal and state income taxes are as follows:

	Year Ended December 31,		
	2006	**2005**	**2004**
		(Dollars in millions)	
Current Tax Provision:			
U.S.			
Federal	$ 246.6	$ 213.9	$ 157.6
State	10.2	27.4	14.0
Foreign	6.4	12.2	-
	263.2	253.5	171.6
Deferred Tax Provision:			
U.S.			
Federal	46.9	86.3	84.5
State	(36.3)	5.5	(48.1)
Foreign	0.3	0.2	-
	10.9	92.0	36.4
Total Tax Provision	$ 274.1	$ 345.5	$ 208.0
Effective Tax Rate	84.9%	39.5%	29.5%

The difference between the statutory federal income tax rate and our effective income tax rate is summarized as follows:

	Year Ended December 31,		
	2006	**2005**	**2004**
Federal Income Tax Rate	35.0%	35.0%	35.0%
Increase (Decrease) as a Result of:			
Nondeductible Goodwill Impairment	70.5%	-	-
Terasen Acquisition Financing Structure	(14.0%)	-	-
Deferred Tax Rate Change	(11.8%)	-	(9.8%)
Kinder Morgan Management Minority Interest	7.4%	1.9%	2.6%
Foreign Earnings Subject to Different Tax Rates	(6.0%)	-	-
Net Effects of Kinder Morgan Energy Partners, L.P.'s Corporate Equity Earnings	3.9%	-	-
State Income Tax, Net of Federal Benefit	4.7%	2.3%	2.1%
Other	(4.8%)	0.3%	(0.4%)
Effective Tax Rate	84.9%	39.5%	29.5%

Income taxes included in the financial statements were composed of the following:

	Year Ended December 31,		
	2006	**2005**	**2004**
		(In millions)	
Continuing Operations	$ 274.1	$ 345.5	$ 208.0
Discontinued Operations	10.0	16.9	14.9
Equity Items	(22.2)	(121.2)	(57.4)
Total	$ 261.9	$ 241.2	$ 165.5

Deferred tax assets and liabilities result from the following:

	December 31, 2006	December 31, 2005
	(In millions)	
Deferred Tax Assets:		
Postretirement Benefits	$ 57.7	$ 24.8
Book Accruals	10.4	21.0
Derivatives	118.6	163.4
Capital Loss Carryforwards	0.9	0.9
Rate Matters	29.3	14.1
Other	5.7	0.3
Total Deferred Tax Assets	222.6	224.5
Deferred Tax Liabilities:		
Property, Plant and Equipment	2,380.0	2,378.5
Investments	953.6	977.7
Prepaid Pension Costs	16.5	11.2
Other	3.5	2.6
Total Deferred Tax Liabilities	3,353.6	3,370.0
Net Deferred Tax Liabilities	$ 3,131.0	$ 3,145.5
Current Deferred Tax Asset	$ 13.0	$ 10.9
Non-current Deferred Tax Liability	3,144.0	3,156.4
Net Deferred Tax Liabilities	$ 3,131.0	$ 3,145.5

During 2006 and 2004, the effective tax rate applied in calculating deferred tax was reduced due to a decrease in the state effective tax rate. As a result, net deferred tax liabilities decreased by approximately $37.8 million in 2006 and $69.4 million in 2004.

During the third quarter of 2005, the Wrightsville power facility (in which we owned an interest) was sold to Arkansas Electric Cooperative Corporation, generating an estimated capital loss for tax purposes of $68.7 million. We did not record a loss for book purposes due to the fact that, for book purposes, we wrote off the carrying value of our investment in the Wrightsville power facility in 2003.

During 2005, in order to offset our capital loss carrryforward expiring in 2005 and our capital loss from the Wrightsville power facility, we sold 5.7 million Kinder Morgan Management shares that we owned, generating a gain for tax purposes of $118.1 million. As a result of these and other transactions, we have remaining at December 31, 2006 a $2.4 million capital loss carryforward that expires $1.6 million during 2008 and $0.8 million during 2009. No valuation allowance has been provided with respect to this deferred tax asset.

10. Financing

As discussed in Note 1(B), beginning January 1, 2006, we have prospectively applied EITF No. 04-5 which has resulted in the inclusion of the accounts and balances of Kinder Morgan Energy Partners in our consolidated financial statements. The adoption of this pronouncement has the effect, among other things, of increasing our consolidated debt beginning January 1, 2006, but has no impact on our consolidated stockholders' equity.

(A) Notes Payable

We and our consolidated subsidiaries had the following unsecured credit facilities outstanding at December 31, 2006.

Credit Facilities

Kinder Morgan, Inc.
$800 million, five-year revolver, due August 2010
Kinder Morgan Energy Partners
$1.85 billion, five-year revolver, due August 2010
Terasen
C$450 million, three-year revolver, due May 2009
Terasen Gas Inc.
C$500 million, three-year revolver, due June 2009
Terasen Pipelines (Corridor) Inc.
C$225 million, 364-day revolver, due January 2007
C$20 million, 364-day demand non-revolver, due January 2007
Terasen Gas (Vancouver Island) Inc.
C$350 million, five-year revolver, due January 2011
C$20 million, seven-year demand non-revolver, due January 2013

The following represent short-term borrowings, issued by the below-listed borrowers, where the commercial paper and bankers' acceptances are supported by each borrower's respective credit facilities. The short-term borrowings shown in the tables below, totaling $1,665.3 million and $610.6 million, respectively, are reported in the caption "Notes Payable" in the accompanying Balance Sheets at December 31, 2006 and 2005, respectively.

	December 31, 2006		
	Borrowings Outstanding Under Credit Facility	Commercial Paper and Bankers' Acceptances Outstanding	Weighted-Average Interest Rate of Short-term Debt Outstanding
	(In millions of U.S. dollars)		
Kinder Morgan, Inc.			
$800 million	$ 90.0	$ -	5.70%
Kinder Morgan Energy Partners[1]			
$1.85 billion	$ -	$ 1,098.2	5.42%
Terasen			
C$450 million	$ -	$ 97.8	4.34%
Terasen Gas Inc.			
C$500 million	$ -	$ 186.2	4.22%
Terasen Pipelines (Corridor) Inc.			
C$225 million	$ -	$ 193.1	4.22%

[1] Due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts and balances of Kinder Morgan Energy Partners are included in our consolidated financial statements as discussed in Note 1(B).

	December 31, 2005		
	Borrowings Outstanding Under Credit Facility	Commercial Paper and Bankers' Acceptances Outstanding	Weighted-Average Interest Rate of Short-term Debt Outstanding
	(In millions of U.S. dollars)		
Kinder Morgan, Inc.			
$800 million	$ -	$ 25.0	4.41%
Terasen			
C$450 million	$ -	$ 196.9	3.12%
Terasen Gas Inc.			
C$500 million	$ -	$ 269.2	3.08%
Terasen Pipelines (Corridor) Inc.			
C$225 million	$ -	$ 119.5	3.16%

At December 31, 2006, we had available an $800 million five-year senior unsecured revolving credit facility dated August 5, 2005. This credit facility replaced an $800 million five-year senior unsecured revolving credit agreement dated August 18, 2004, effectively extending the maturity of the facility by one year. As with the former credit facility, this credit facility can be used for general corporate purposes, including serving as support for our commercial paper program, and includes covenants and requires payment of facility fees that are common in such arrangements. In this credit facility (i) the definition of consolidated net worth, which is a component of total capitalization, excludes other comprehensive income/loss, (ii) (as amended on October 6, 2005) the definition of consolidated indebtedness excludes the debt of Kinder Morgan Energy Partners that is guaranteed by us and (iii) the effect of consolidating Kinder Morgan Energy Partners, relating to the requirements of EITF No. 04-5 discussed in Note 1(B), has been excluded. Under this bank facility, we are required to pay a facility fee based on the total commitment, whether used or unused, at a rate that varies based on our senior debt rating. This credit facility includes the financial covenant that consolidated indebtedness is not to exceed 65% of total capitalization.

The following constitute events of default under the credit facility, subject to certain cure periods:

- Nonpayment of interest, principal or fees;
- Failure to make required payments under hedging agreements that exceed $100,000,000;
- Adverse judgments in excess of $75,000,000; and
- Voluntary or involuntary bankruptcy or liquidation.

Based on our credit rating at December 31, 2006, our annual facility fee is 10 basis points on the total credit amount of $800 million. Average borrowings outstanding under this credit facility during 2006 were $114.6 million at a weighted-average interest rate of 5.77%. No amounts were outstanding under this bank facility during 2005.

On November 23, 2005, 1197774 Alberta ULC, a wholly owned subsidiary of Kinder Morgan, Inc., entered into a 364-day credit agreement, with Kinder Morgan, Inc. as guarantor, which provides for a committed credit facility in the Canadian dollar equivalent of US$2.25 billion. This credit facility was used to finance the cash portion of the acquisition of Terasen (see Note 4), but could also be used for general corporate purposes. Under this bank facility, a facility fee is required to be paid based on the total commitment, whether used or unused, at a rate that varies based on Kinder Morgan, Inc.'s senior debt rating. On November 30, 2005, 1197774 Alberta ULC borrowed $2.1 billion under this facility to finance the cash portion of the acquisition of Terasen. The facility was terminated when the loan was repaid on December 9, 2005 after permanent financing was obtained as discussed further in this section. Interest paid during 2005 under this credit facility was $1.9 million.

At December 31, 2006, Kinder Morgan Energy Partners had a $1.85 billion five-year unsecured credit facility with a syndicate of financial institutions and Wachovia Bank, National Association as the administrative agent. Effective August 28, 2006, Kinder Morgan Energy Partners terminated its $250 million unsecured nine-month bank credit facility due November 21, 2006, and increased its existing five-year bank credit facility from $1.60 billion to $1.85 billion and can now be amended to allow for borrowings up to $2.1 billion. The $1.85 billion credit facility can be used for general corporate purposes and to support commercial paper issuance. This credit facility is due August 18, 2010 and includes covenants and requires payment of facility fees that are common in such arrangements. The $1.85 billion credit facility permits Kinder Morgan Energy Partners to obtain bids for fixed rate loans from members of the lending syndicate. Interest on the credit facility accrues at Kinder Morgan Energy Partners' option at a floating rate equal to either the administrative agent's base rate (but not less than the Federal Funds Rate, plus 0.5%), or London Interbank Offered Rate ("LIBOR"), plus a margin, which varies depending upon the credit rating of Kinder Morgan Energy Partners' long-term senior unsecured debt. Excluding the relatively non-restrictive specified negative covenants and events of defaults, the credit facility does not contain any provisions designed to protect against a situation where a party to an agreement is unable to find a basis to terminate that agreement while its counterparty's impending financial collapse is revealed and perhaps hastened through the default structure of some other agreement. The credit facility does not contain a material adverse change clause coupled with a lockbox provision; however, the facility does provide that the margin Kinder Morgan Energy Partners will pay with respect to borrowings and the facility fee that Kinder Morgan Energy Partners will pay on the total commitment will vary based on Kinder Morgan Energy Partners' senior debt investment rating. None of Kinder Morgan Energy Partners debt is subject to payment acceleration as a result of any change to their credit ratings.

The Kinder Morgan Energy Partners $1.85 billion credit facility includes the following restrictive covenants:

- Total debt divided by earnings before interest, income taxes, depreciation and amortization for the preceding four quarters may not exceed (i) 5.5, in the case of any such period ended on the last day of (1) a fiscal quarter in which Kinder Morgan Energy Partners makes any Specified Acquisition, or (2) the first or second fiscal quarter next succeeding such a fiscal quarter or (ii) 5.0, in the case of any such period ended on the last day of any other fiscal quarter;

- Certain limitations on entering into mergers, consolidations and sales of assets;

- Limitations on granting liens; and

- Prohibitions on making any distribution to holders of units if an event of default exists or would exist upon making such distribution.

The following constitute events of default under the credit facility, subject to certain cure periods:

- Nonpayment of interest, principal or fees;

- Failure to make required payments under hedging agreements that equal or exceed $75,000,000;

- Failure of the general partner of Kinder Morgan Energy Partners to make required payments equal to or in excess of $75,000,000;

- Adverse judgments in excess of $75,000,000; and

- Voluntary or involuntary bankruptcy or liquidation.

Based on Kinder Morgan Energy Partners' credit rating at December 31, 2006, the annual facility fee is 8 basis points on the total credit amount.

On February 22, 2006, Kinder Morgan Energy Partners entered into a nine-month $250 million credit facility due November 21, 2006 with a syndicate of financial institutions, and Wachovia Bank, National Association as the administrative agent. Borrowings under the credit facility can be used for general corporate purposes and as backup for Kinder Morgan Energy Partners' commercial paper program and include financial covenants and events of default that are common in such arrangements. This agreement was terminated concurrent with Kinder Morgan Energy Partners' increase of its 5-year credit facility from $1.6 billion to $1.85 billion.

On April 28, 2006, Rockies Express Pipeline LLC entered into a $2.0 billion five-year, unsecured revolving credit facility due April 28, 2011. This credit facility supports a $2.0 billion commercial paper program that was established in May 2006, and borrowings under the commercial paper program reduce the borrowings allowed under the credit facility. This facility can be amended to allow for borrowings up to $2.5 billion. Borrowings under the Rockies Express credit facility and commercial paper program are primarily used to finance the construction of the Rockies Express interstate natural gas pipeline and to pay related expenses, and the borrowings do not reduce the borrowings allowed under our credit facilities described elsewhere in this report. Additionally, effective June 30, 2006, West2East Pipeline LLC (and its subsidiary Rockies Express Pipeline LLC) was deconsolidated and subsequently is accounted for under the equity method of accounting See Note 4. All three owners have agreed to guarantee borrowings under the Rockies Express credit facility and under the Rockies Express commercial paper program in the same proportion as their percentage ownership of the member interests in Rockies Express Pipeline LLC. As of December 31, 2006, Rockies Express Pipeline LLC had $790.1 million of commercial paper outstanding, and there were no borrowings under its five-year credit facility. Accordingly, as of December 31, 2006, Kinder Morgan Energy Partners' contingent share of Rockies Express' debt was $403.0 million.

At December 31, 2006, Terasen Inc. had available a C$450 million three-year revolving credit facility dated May 9, 2006. This facility replaced three bi-lateral facilities aggregating C$450 million and includes terms and conditions similar to the facilities it replaced. This credit facility can be used for general corporate purposes and to support the issuance of bankers' acceptances. Under this facility, Terasen is required to pay a standby fee based on the total unused commitment, at a rate that varies based on Terasen's senior debt rating.

The Terasen Inc. credit facility includes the following financial covenants:

- Total debt not to exceed 75% of total debt plus shareholder's equity;
- Interest coverage ratio not less than 1.25:1; and
- Subordinated cash interest ratio not less than 1.00:1.

The following constitute events of default under the credit facility, subject to certain cure periods:

- Nonpayment of interest, principal or fees;
- Unsatisfied awards; and
- Voluntary or involuntary bankruptcy or liquidation.

Based on Terasen Inc.'s credit rating at December 31, 2006, the annual standby fee is 15.5 basis points on the unutilized commitment.

At December 31, 2006, Terasen Gas Inc. had available a C$500 million three-year revolving credit facility dated June 21, 2006. This facility replaces five bi-lateral facilities aggregating C$500 million and includes terms and conditions similar to the facilities it replaced. The facility has a term of 364 days, extendible annually for an additional 364 days at the option of the lenders. The credit facility can be used for general corporate purposes and to support commercial paper issuance. Under this facility, Terasen Gas Inc. is required to pay a standby fee based on the total unused commitment, at rates that vary based on Terasen Gas Inc.'s senior debt rating. This credit facility includes the financial covenant that total indebtedness is not to exceed 75% of total capitalization.

The following constitute events of default under the credit facility, subject to certain cure periods:

- Nonpayment of interest, principal or fees;
- Unsatisfied judgments in excess of C$25,000,000; and
- Voluntary or involuntary bankruptcy or liquidation.

Based on Terasen Gas Inc.'s credit rating at December 31, 2006, the annual standby fee is 8.5 basis points on the unutilized commitment.

At December 31, 2006, Terasen Pipelines (Corridor) Inc. had available a C$225 million senior unsecured revolving credit facility. The facility has a term of 364 days, extendible annually for an additional 364 days at the option of the lenders, with a three-year term-out provision if the banks do not extend. This credit facility can be used for general corporate purposes and to support commercial paper issuance. The facility has associated, a $20 million demand facility put in place for overdraft purposes and short-term cash management. At December 31, 2006, $0.2 million was outstanding under the C$20 million demand facility at a weighted-average interest rate 6.00%. Under these facilities, Terasen Pipelines (Corridor) Inc. is required to pay a standby fee based on the total unused commitment, at a rate that varies based on Terasen Pipelines (Corridor) Inc.'s senior debt rating.

This credit facility includes the following financial covenants:

- Indebtedness to rate base ratio not to exceed 75%.

The following constitute events of default under the credit facility, subject to certain cure periods:

- Nonpayment of interest, principal or fees;
- Unsatisfied judgments in excess of C$15,000,000; and

- Voluntary or involuntary bankruptcy or liquidation.

Based on Terasen Pipelines (Corridor) Inc.'s credit rating at December 31, 2006, the annual standby fee is 10 basis points on the unutilized commitment.

At December 31, 2006, TGVI had outstanding a five-year C$350 million unsecured committed revolving credit facility dated January 13, 2006 with a syndicate of banks. As discussed in "Long-term Debt" following, TGVI intended and had the ability to refinance its short-term borrowings on a long-term basis under this long-term credit facility. Accordingly, borrowings outstanding against the C$350 million credit facility have been classified as long-term debt in our accompanying Consolidated Balance Sheets at December 31, 2006 and 2005.

The following represents average short-term commercial paper and bankers' acceptance programs outstanding and the weighted-average interest rates during the period, issued by the below listed borrowers, which are supported by the previously described credit facilities. These borrowings are comprised of unsecured short-term notes with maturities not to exceed 364 days from the date of issue.

	Twelve Months Ended December 31, 2006		Twelve Months Ended December 31, 2005	
	Average Short-term Debt Outstanding	Weighted-Average Interest Rate of Short-term Debt Outstanding	Average Short-term Debt Outstanding	Weighted-Average Interest Rate of Short-term Debt Outstanding
	(In millions of U.S. dollars)			
Kinder Morgan, Inc.				
$800 million	$ 6.6	4.77%	$ 198.1	3.47%
Kinder Morgan Energy Partners[1]				
$1.85 billion	$1,000.8	5.16%	$ -	-%
Terasen				
C$450 million	$ 92.0	4.69%	$ 209.3	3.10%
Terasen Gas Inc.				
C$500 million	$ 169.3	4.03%	$ 265.7	3.04%
Terasen Pipelines (Corridor) Inc.				
C$225 million	$ 134.9	3.93%	$ 120.7	3.03%

[1] Due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts and balances of Kinder Morgan Energy Partners are included in our consolidated financial statements as discussed in Note 1(B).

Commercial paper issued by us and supported by the $800 million bank facility are unsecured short-term notes with maturities not to exceed 270 days from the date of issue. During the first five months of 2006, all commercial paper under this facility was redeemed within 4 days, with interest rates ranging from 4.33% to 5.15%. As discussed in Note 1(A), on August 28, 2006, we entered into a definitive merger agreement, based on a proposal we received on May 28, 2006, under which investors led by Richard D. Kinder, our Chairman and Chief Executive Officer, will acquire all of our outstanding common stock for $107.50 per share. With the anticipated increase in debt that would result if the transaction is consummated and the uncertainty that the Going Private transaction or any other proposals or extraordinary transaction will be approved or completed has limited our access to the commercial paper market. As a result, we began utilizing our $800 million credit facility for Kinder Morgan, Inc.'s short-term borrowing needs in June of 2006.

Commercial paper issued by Kinder Morgan Energy Partners are unsecured short-term notes with maturities not to exceed 270 days from the date of issue. During 2006, all of Kinder Morgan Energy Partners' commercial paper was redeemed within 71 days, with interest rates ranging from 5.60% to 4.33%.

Bankers' acceptances issued by Terasen Inc. are unsecured short-term notes with maturities not to exceed 364 days from the date of issue. During 2006, all of Terasen Inc.'s bankers' acceptances were redeemed within 93 days, with interest rates ranging from 3.88% to 4.45%. Terasen Gas Inc.'s floating rate bankers' acceptances have associated floating-to-fixed interest rate swap agreements that effectively convert the related interest expense from floating to fixed rates. See Note 12 for additional information on these swap agreements.

Commercial paper issued by Terasen Gas Inc. are unsecured short-term notes with maturities not to exceed 364 days from the date of issue. During 2006, all of Terasen Gas Inc.'s commercial paper was redeemed within 97 days, with interest rates ranging from 3.17% to 4.41%.

Commercial paper issued by Terasen Pipelines (Corridor) Inc. are unsecured short-term notes with maturities not to exceed 364 days from the date of issue. During 2006, all of Terasen Pipelines (Corridor's) commercial paper was redeemed within 140 days, with interest rates ranging from 3.22% to 4.33%.

(B) Long-term Debt

	December 31,	
	2006	2005
	(In millions)	
Kinder Morgan, Inc.		
Debentures:		
6.50% Series, Due 2013	$ 35.0	$ 40.0
7.35% Series, Due 2026	-	125.0
6.67% Series, Due 2027	150.0	150.0
7.25% Series, Due 2028	493.0	493.0
7.45% Series, Due 2098	150.0	150.0
Senior Notes:		
6.80% Series, Due 2008	300.0	300.0
6.50% Series, Due 2012	1,000.0	1,000.0
5.15% Series, Due 2015	250.0	250.0
Deferrable Interest Debentures Issued to Subsidiary Trusts:		
8.56% Junior Subordinated Deferrable Interest Debentures Due 2027	103.1	103.1
7.63% Junior Subordinated Deferrable Interest Debentures Due 2028	180.5	180.5
Carrying Value Adjustment for Interest Rate Swaps[1]	24.1	54.9
Unamortized Gain (Loss) on Termination of Interest Rate Swap	(2.7)	(3.2)
Kinder Morgan Finance Company, ULC		
5.35% Series, Due 2011	750.0	750.0
5.70% Series, Due 2016	850.0	850.0
6.40% Series, Due 2036	550.0	550.0
Carrying Value Adjustment for Interest Rate Swaps[1]	(18.7)	-
Kinder Morgan Energy Partners[2]		
Senior Notes:		
5.35% Series, Due 2007	250.0	-
6.30% Series, Due 2009	250.0	-
7.50% Series, Due 2010	250.0	-
6.75% Series, Due 2011	700.0	-
7.125% Series, Due 2012	450.0	-
5.00% Series, Due 2013	500.0	-
5.125% Series, Due 2014	500.0	-
7.40% Series, Due 2031	300.0	-
7.75% Series, Due 2032	300.0	-
7.30% Series, Due 2033	500.0	-
5.80% Series, Due 2035	500.0	-
Other	1.1	-
Carrying Value Adjustment for Interest Rate Swaps[1]	42.6	-
Central Florida Pipe Line LLC[2]		-
7.84% Series, Due 2008	10.0	-
Arrow Terminals L.P. [2]		
Illinois Development Finance Authority Adjustable Rate Industrial Development Revenue Bonds, Due 2010, weighted-average interest rate of 4.089%	5.3	-
Kinder Morgan Texas Pipeline, L.P. [2]		
8.85% Series, Due 2014	49.1	-
KM Liquids Terminals LLC[2]		
New Jersey Economic Development Revenue Refunding Bonds, Due 2018, 3.87%	25.0	-

Kinder Morgan Operating, L.P. "B" 2		
Jackson-Union Counties Illinois Regional Port District Tax-exempt Floating Rate Bonds, Due 2024, weighted-average interest rate of 3.90%	23.7	-
Other	0.2	-
International Marine Terminals[2]		
Plaquemines Port, Harbor and Terminal District (Louisiana) Adjustable Rate Annual Tender Port Facilities Revenue Refunding Bonds, Due 2025, weighted-average interest rate of 3.50%	40.0	-
Terasen Inc.[4]		
Medium Term Notes:		
6.30% Series 1, Due 2008[3]	178.3	181.9
4.85% Series 2, Due 2006[3]	-	86.3
5.56% Series 3, Due 2014[3]	112.4	113.1
8% Capital Securities, Due 2040[3]	106.9	107.1
Carrying Value Adjustment for Interest Rate Swaps[1]	1.1	0.1
Terasen Gas Inc. [4]		
Purchase Money Mortgages:		
11.80% Series A, Due 2015	64.3	64.5
10.30% Series B, Due 2016	171.6	172.0
Debentures and Medium Term Notes:		
9.75% Series D, Due 2006	-	17.2
10.75% Series E, Due 2009	51.4	51.5
6.20% Series 9, Due 2008	161.4	161.7
6.95% Series 11, Due 2029	128.7	129.0
6.50% Series 13, Due 2007	85.8	86.0
6.15% Series 16, Due 2006	-	86.0
6.50% Series 18, Due 2034	128.7	129.0
5.90% Series 19, Due 2035	128.7	129.0
5.55% Series 21, Due 2036	103.0	
Floating Rate Series 20, interest rate of 4.55% (2005 – 3.36%), Due 2007	128.7	129.0
Obligations under Capital Leases, at 5.62% (2005 – 6.07%)	6.2	7.5
Terasen Gas (Vancouver Island) Inc.[4]		
Syndicated credit facility at short-term floating rates, weighted-average interest rate of 4.41% with estimated maturities of $26.4 million in 2007	257.2	180.1
Government Loans (See Note 15(D))	3.1	-
Terasen Pipelines (Corridor) Inc. [4]		
Debentures:		
4.24% Series A, Due 2010	128.7	129.0
5.033% Series B, Due 2015	128.7	129.0
Unamortized Premium on Long-term Debt	2.5	2.9
Unamortized Debt Discount on Long-term Debt	(16.7)	(8.4)
Current Maturities of Long-term Debt	(511.2)	(347.4)
Total Long-term Debt	$ 11,060.8	$ 6,729.4

1 Adjustment of carrying value of long-term securities subject to outstanding interest rate swaps; see Note 12.

2 Due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts and balances of Kinder Morgan Energy Partners and its consolidated subsidiaries are included in our consolidated financial statements.

3 Includes purchase accounting adjustments, made to adjust the carrying values of the debt instruments and related interest rate swap agreements to their fair values at the date of acquisition. The adjustments are being amortized monthly over the term of the Notes and Capital Securities.

4 Debt issued under Terasen Inc. and its subsidiaries is denominated in Canadian dollars but has been converted to U.S. dollars at the exchange rate at December 31, 2006 of 0.8581.

Kinder Morgan, Inc.

The 2013 Debentures are not redeemable prior to maturity. The 2028 and 2098 Debentures and the 2008 and 2012 Senior Notes are redeemable in whole or in part, at our option at any time, at redemption prices defined in the associated prospectus supplements. The 2028 Debentures and 2012 Senior Notes have associated fixed-to-floating interest rate swap agreements that effectively convert the related interest expense from fixed rates to floating rates based on the three-month LIBOR. See Note 12 for additional information on these swap agreements. The 2015 Senior Notes are redeemable in whole or in part at our option, but at redemption prices that generally do not make early redemption an economically favorable alternative. The 2027 Debentures are redeemable in whole or in part, at our option after November 1, 2004 at redemption prices defined in the associated prospectus supplements, which redemption prices generally do not make early redemption an economically favorable alternative.

In July 2006, we received notification of election from the holders of our 7.35% Series Debentures due 2026 electing the option, as provided in the indenture governing the debentures, to require us to redeem the securities on August 1, 2006. The full $125 million of principal was elected to be redeemed and was paid, along with accrued interest of approximately $4.6 million, on August 1, 2006, utilizing incremental borrowing under our $800 million credit facility.

On March 15, 2005, we issued $250 million of our 5.15% Senior Notes due March 1, 2015. The proceeds of $248.5 million, net of underwriting discounts and commissions, were used to repay short-term commercial paper debt that was incurred to pay our 6.65% Senior Notes that matured on March 1, 2005.

On March 1, 2005, our $500 million of 6.65% Senior Notes matured, and we paid the holders of the notes, utilizing a combination of cash on hand and borrowings under our commercial paper program.

On October 21, 2004, we retired our $75 million 8.75% Debentures due October 15, 2024 at a premium of 104.0% of the face amount. We recorded a loss of $2.4 million (net of associated tax benefit of $1.5 million) in connection with this early extinguishment of debt, which is included under the caption "Other, Net" in the accompanying Consolidated Statement of Operations for 2004.

Kinder Morgan Finance Company, ULC

On December 9, 2005, Kinder Morgan Finance Company, ULC issued $750 million of 5.35% Senior Notes due 2011, $850 million of 5.70% Senior Notes due 2016 and $550 million of 6.40% Senior Notes due 2036. The 2011, 2016 and 2036 Senior Notes issued by Kinder Morgan Finance Company, ULC are redeemable in whole or in part, at our option at any time, at redemption prices defined in the associated prospectus supplements. Each series of these notes is fully and unconditionally guaranteed by Kinder Morgan, Inc. on a senior unsecured basis as to principal, interest and any additional amounts required to be paid as a result of any withholding or deduction for Canadian taxes. The proceeds of $2.1 billion, net of underwriting discounts and commissions, were ultimately distributed to repay in full the bridge facility incurred to finance the cash portion of the consideration for Kinder Morgan, Inc.'s acquisition of Terasen on November 30, 2005 (see Note 4). These notes were sold in a private placement pursuant to a Purchase Agreement, dated December 6, 2005 among Kinder Morgan Finance Company, ULC, Kinder Morgan, Inc. and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Citigroup Global Markets Inc., as representatives of the several initial purchasers named in the Purchase Agreement, and resold by the initial purchasers to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933. The notes have not been registered under the Securities Act and may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirements. In February 2006, Kinder Morgan Finance Company, ULC exchanged these notes for substantially identical notes that have been registered under the Securities Act.

Kinder Morgan Energy Partners

Kinder Morgan Energy Partners' fixed rate notes provide for redemption at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date plus a make-whole premium. Approximately $2.1 billion of Kinder Morgan Energy Partners' Senior Notes have associated fixed-to-floating interest rate swap agreements that effectively convert the related interest expense from fixed rates to floating rates. See Note 12 for additional information on these swap agreements.

Central Florida Pipeline LLC Debt

Effective January 1, 2001, Kinder Morgan Energy Partners acquired Central Florida Pipeline LLC. As part of Kinder Morgan Energy Partners' purchase price, Kinder Morgan Energy Partners assumed an aggregate principal amount of $40 million of senior notes originally issued to a syndicate of eight insurance companies. The senior notes have a fixed annual interest rate of 7.84% with repayments in annual installments of $5 million beginning July 23, 2001. The final payment is due July 23, 2008.

Interest is payable semiannually on January 1 and July 23 of each year. In July 2006, Kinder Morgan Energy Partners made an annual repayment of $5.0 million.

Arrow Terminals L.P.

Effective October 6, 2004, Kinder Morgan Energy Partners acquired Global Materials Services LLC and its consolidated subsidiaries. Kinder Morgan Energy Partners renamed Global Materials Services LLC as Kinder Morgan River Terminals LLC, and as part of Kinder Morgan Energy Partners' purchase price, Kinder Morgan Energy Partners assumed debt of $33.7 million, consisting of third-party notes payables, current and non-current bank borrowings, and long-term bonds payable. In October 2004, Kinder Morgan Energy Partners paid $28.4 million of the assumed debt and following these repayments, the only remaining outstanding debt was a $5.3 million principal amount of Adjustable Rate Industrial Development Revenue Bonds issued by the Illinois Development Finance Authority. Kinder Morgan Energy Partners' subsidiary, Arrow Terminals L.P., is the obligor on these bonds. The bonds have a maturity date of January 1, 2010, and interest on these bonds is paid and computed quarterly at the Bond Market Association Municipal Swap Index. The bonds are collateralized by a first mortgage on assets of Arrow's Chicago operations and a third mortgage on assets of Arrow's Pennsylvania operations. As of December 31, 2006, the interest rate was 4.089%. The bonds are also backed by a $5.4 million letter of credit issued by JP Morgan Chase that backs-up the $5.3 million principal amount of the bonds and $0.1 million of interest on the bonds for up to 45 days computed at 12% per annum on the principal amount thereof.

Kinder Morgan Texas Pipeline, L.P. Debt

Effective August 1, 2005, Kinder Morgan Energy Partners acquired a natural gas storage facility in Liberty County, Texas. As part of Kinder Morgan Energy Partners' purchase price, Kinder Morgan Energy Partners assumed debt having a fair value of $56.5 million. Kinder Morgan Energy Partners valued the debt equal to the present value of amounts to be paid determined using an approximate interest rate of 5.23%. The debt consisted of privately placed unsecured senior notes with a fixed annual stated interest rate as of August 1, 2005, of 8.85%. The assumed principal amount, along with interest, is due in monthly installments of approximately $0.7 million. The final payment is due January 2, 2014. Kinder Morgan Energy Partners' subsidiary, Kinder Morgan Texas Pipeline, L.P., is the obligor on the notes.

Additionally, the unsecured senior notes may be prepaid at any time in amounts of at least $1.0 million at a price equal to the higher of par value or the present value of the remaining scheduled payments of principal and interest on the portion being prepaid. The notes also contain certain covenants similar to those contained in Kinder Morgan Energy Partners' current five-year, unsecured revolving credit facility. Kinder Morgan Energy Partners does not believe that these covenants will materially affect distributions to the partners of Kinder Morgan Energy Partners.

Kinder Morgan Liquids Terminals LLC Debt

In November 2001, Kinder Morgan Energy Partners acquired a liquids terminal in Perth Amboy, New Jersey from Stolthaven Perth Amboy Inc. and Stolt-Nielsen Transportation Group, Ltd. As part of Kinder Morgan Energy Partners' purchase price, Kinder Morgan Energy Partners assumed $25.0 million of Economic Development Revenue Refunding Bonds issued by the New Jersey Economic Development Authority. These bonds have a maturity date of January 15, 2018. Interest on these bonds is computed on the basis of a year of 365 or 366 days, as applicable, for the actual number of days elapsed during Commercial Paper, Daily or Weekly Rate Periods and on the basis of a 360-day year consisting of twelve 30-day months during a Term Rate Period. As of December 31, 2006, the interest rate was 3.87%. Kinder Morgan Energy Partners has an outstanding letter of credit issued by Citibank in the amount of $25.3 million that backs-up the $25.0 million principal amount of the bonds and $0.3 million of interest on the bonds for up to 42 days computed at 12% on a per annum basis on the principal thereof.

Kinder Morgan Operating L.P. "B" Debt

This $23.7 million principal amount of tax-exempt bonds due April 1, 2024 was issued by the Jackson-Union Counties Regional Port District. These bonds bear interest at a weekly floating market rate. As of December 31, 2006, the interest rate on these bonds was 3.90%. As of December 31, 2006, Kinder Morgan Energy Partners had an outstanding letter of credit issued by Wachovia in the amount of $24.1 million that backs-up the $23.7 million principal amount of the bonds and $0.4 million of interest on the bonds for up to 55 days computed at 12% per annum on the principal amount thereof.

International Marine Terminals Debt

Since February 1, 2002, Kinder Morgan Energy Partners has owned a 66 2/3% interest in International Marine Terminals partnership. The principal assets owned by IMT are dock and wharf facilities financed by the Plaquemines Port, Harbor and Terminal District (Louisiana) $40,000,000 Adjustable Rate Annual Tender Port Facilities Revenue Refunding Bonds (International Marine Terminals Project) Series 1984A and 1984B. As of December 31, 2006, the interest rate on these bonds was 3.50%.

On March 15, 2005, these bonds were refunded and the maturity date was extended from March 15, 2006 to March 15, 2025. No other changes were made under the bond provisions. The bonds are backed by two letters of credit issued by KBC Bank N.V. On March 19, 2002, an Amended and Restated Letter of Credit Reimbursement Agreement relating to the letters of credit in the amount of $45.5 million was entered into by IMT and KBC Bank. In connection with that agreement, Kinder Morgan Energy Partners agreed to guarantee the obligations of IMT in proportion to their ownership interest. Kinder Morgan Energy Partners' obligation is approximately $30.3 million for principal, plus interest and other fees.

Terasen Inc.

The Medium Term Notes are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 21, 2001. Terasen Inc.'s Series 1 and Series 3 Medium Term Notes are redeemable in whole or in part at the option of Terasen Inc. at prices defined in the associated Trust Indenture, which redemption prices generally do not make early redemption an economically favorable alternative. Terasen Inc.'s Medium Term Notes have associated fixed-to-floating interest rate swap agreements that effectively convert a majority of the related interest expense from fixed rates to floating rates. See Note 12 for additional information on these swap agreements.

On May 8, 2006, Terasen Inc.'s C$100 million of 4.85%, Series 2 Medium Term Notes matured and Terasen Inc. paid the holders of the notes, utilizing a combination of incremental short-term borrowing and proceeds from the sale of Terasen Water and Utility Services (see Note 7).

Terasen Gas Inc.

The Series A and Series B Purchase Money Mortgages are collateralized equally and ratably by a first fixed and specific mortgage and charge on Terasen Gas' Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to C$425 million. The Debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented. The Series A Purchase Money Mortgage, Series 9 and Series 20 Debentures and Medium Term Notes are not redeemable prior to maturity. Terasen Gas Inc.'s Series B Purchase Money Mortgages, Series E, Series 11, Series 13, Series 18, Series 19 and Series 21 Debentures and Medium Term Notes are redeemable in whole or in part at the option of Terasen Gas Inc. at prices defined in the associated Trust Indenture, which redemption prices generally do not make early redemption an economically favorable alternative.

The obligations under capital leases represent fleet vehicles that Terasen Gas, Inc. has leased from PHH Aral. The term of the leases is either 7 or 10 years, depending on the type of vehicle leased, and is fully collateralized by the vehicles themselves.

On September 25, 2006, Terasen Gas Inc. issued C$120 million 5.55% Medium Term Note debentures, due September 25, 2036. Of the $106.9 million (C$119.4 million) net proceeds from this issuance after underwriting discounts and commissions, $89.5 million (C$100 million) were used to repay short-term commercial paper debt that was primarily incurred to pay Terasen Gas Inc.'s C$100 million 6.15% medium term note debentures that matured on July 31, 2006. The remaining proceeds were used to repay Terasen Gas Inc.'s C$20 million 9.75% notes, which matured on December 17, 2006.

On July 31, 2006, Terasen Gas Inc.'s C$100 million 6.15% Medium Term Note debentures matured, and the note holders were paid utilizing a combination of cash on hand and incremental short-term borrowing.

Terasen Gas (Vancouver Island) Inc.

The five-year C$350 million unsecured committed revolving credit facility with a syndicate of banks was entered into on January 13, 2006 replacing TGVI's former term facility and intercompany advances from Terasen. The outstanding balance under this facility consists of banker's acceptances which have terms not to exceed 180 days at the end of which time they are replaced by new banker's acceptances. The facility can also be utilized to finance working capital requirements and for general corporate purposes. The terms and conditions are similar to those of the previous facility and common for such term facilities. Concurrently with executing this facility, TGVI entered into a C$20 million seven-year unsecured committed non-revolving credit facility with one bank. This facility will be utilized for purposes of refinancing any annual prepayments that TGVI may be required to make on non-interest bearing government contributions. The terms and conditions are primarily the same as the aforementioned TGVI facility except this facility ranks junior to repayment of TGVI's Class B subordinated debt, which is held by its parent company, Terasen. At December 31, 2006, TGVI had outstanding bankers' acceptances under the C$350 million credit facility with an average term of less than three months. While the bankers' acceptances are short term, the underlying credit facility on which the bankers' acceptances are committed is open through January 2011. Accordingly, under the C$350 million credit facility, borrowings outstanding at December 31, 2006 of $230.8 million have been classified as long-term debt and an estimated $23.2 million as current maturities in our accompanying Consolidated Balance Sheet. Borrowings outstanding against the former facility of $180.1 million were classified as long-term debt and $151.7 million as current maturities in our accompanying Consolidated Balance Sheet at December 31, 2005. Borrowings outstanding against the C$20 million credit facility at December 31, 2006 were $3.2 million at a weighted-average interest rate of 4.32%. TGVI's credit facility has associated floating-to-fixed interest rate swap agreements that effectively convert the related interest expense from floating to fixed rates. See Note 12 for additional information on these swap agreements.

On June 30, 2006, TGVI made a $5.6 million (C$6.2 million) payment on its government loans, of which, approximately $3.3 million (C$3.7 million) was refinanced through borrowings under its C$20 million non-revolving credit facility and the remaining amount funded with cash on hand. Additional information on the government loans can be found in Note 15(D).

Terasen Pipelines (Corridor) Inc.

Terasen Pipelines (Corridor) Inc.'s Series A and Series B Debentures are redeemable in whole or in part at the option of Terasen Pipelines (Corridor) Inc. at prices defined in the associated Trust Indenture, which redemption prices generally do not make early redemption an economically favorable alternative. Terasen Pipelines (Corridor) Inc.'s Debentures have associated fixed-to-floating interest rate swap agreements that effectively convert the related interest expense from fixed rates to floating rates. See Note 12 for additional information on these swap agreements.

Maturities of long-term debt (in millions) for the five years ending December 31, 2011 are $511.2, $657.1, $314.2, $397.2 and $1,694.3, respectively.

At December 31, 2006 and 2005, the carrying amount of our long-term debt was $11.6 billion and $7.1 billion, respectively. The estimated fair values of our long-term debt at December 31, 2006 and 2005 are shown in Note 16.

(C) Capital Trust Securities

Our business trusts, K N Capital Trust I and K N Capital Trust III, are obligated for $100 million of 8.56% Capital Trust Securities maturing on April 15, 2027 and $175 million of 7.63% Capital Trust Securities maturing on April 15, 2028, respectively, which are guaranteed by us. The 2028 Securities are redeemable in whole or in part, at our option at any time, at redemption prices as defined in the associated prospectus, but at redemption prices that generally do not make early redemption an economically favorable alternative. The 2027 Securities are redeemable in whole or in part (i) at our option after April 14, 2007 and (ii) at any time in certain limited circumstances upon the occurrence of certain events and at prices, all defined in the associated prospectus supplements. Upon redemption by us or at maturity of the Junior Subordinated Deferrable Interest Debentures, we must use the proceeds to make redemptions of the Capital Trust Securities on a pro rata basis. As a result of adopting FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, effective December 31, 2003, we (i) no longer include the transactions and balances of K N Capital Trust I and K N Capital Trust III in our consolidated financial statements and (ii) began including our Junior Subordinated Deferrable Interest Debentures issued to the Capital Trusts in a separate caption under the heading "Long-term Debt" in our Consolidated Balance Sheets. In addition, effective July 1, 2003 we (i) reclassified our trust preferred securities to the debt portion of our balance sheet and (ii) began classifying payments made by us in conjunction with the trust preferred securities as interest expense, rather than minority interest. For periods and dates prior to July 1, 2003, the Capital Trust Securities are treated as a minority interest, shown in our Consolidated Balance Sheets under the caption "Kinder Morgan-Obligated Mandatorily Redeemable Preferred Capital Trust Securities of Subsidiary Trust Holding Solely Debentures of Kinder Morgan," and periodic payments made to the holders of these securities are classified under "Minority Interests" in our Consolidated Statements of Operations. See Note 16 for the fair value of these securities.

(D) Capital Securities

Terasen Inc. has C$125 million of 8% Capital Securities, which mature in 2040. Election options on these securities include: (i) to defer payments, (ii) to settle such deferred payments in either cash or Terasen Inc. common shares and (iii) to settle principal at maturity through the issuance of Terasen Inc. common shares. The securities are exchangeable at the option of the holder on or after April 19, 2010 for common shares of Terasen Inc. at 90% of the market price, subject to the right of Terasen Inc. to redeem the securities for cash.

(E) Common Stock

On February 14, 2007, we paid a cash dividend on our common stock of $0.875 per share to stockholders of record as of January 31, 2007.

On August 28, 2006, we entered into a definitive merger agreement under which investors led by Richard D. Kinder, our Chairman and Chief Executive Officer, will acquire all of our outstanding common stock for $107.50 per share in cash. Both our board of directors, on the unanimous recommendation of a special committee composed entirely of independent directors, and our stockholders have approved the agreement. The transaction is expected to be completed in the first or second quarter of 2007, subject to receipt of regulatory approvals and the satisfaction of other customary closing conditions.

As discussed in Note 4, on November 30, 2005, we completed the acquisition of Terasen. Terasen shareholders were able to elect, for each Terasen share held, either (i) C$35.75 in cash, (ii) 0.3331 shares of Kinder Morgan, Inc. common stock, or (iii) C$23.25 in cash plus 0.1165 shares of Kinder Morgan, Inc. common stock. In the aggregate, we issued approximately $1.1 billion (12.48 million shares) of Kinder Morgan Inc. common stock and paid approximately C$2.49 billion (US$2.13 billion) in cash to Terasen securityholders.

On August 14, 2001, we announced a plan to repurchase $300 million of our outstanding common stock, which program was increased to $400 million, $450 million, $500 million, $550 million, $750 million, $800 million and $925 million in February 2002, July 2002, November 2003, April 2004, November 2004, April 2005 and November 2005, respectively. As of December 31, 2006, we had repurchased a total of approximately $906.8 million (14,934,300 shares) of our outstanding common stock under the program, of which $31.5 million (339,800 shares), $314.1 million (3,865,800 shares) and $108.6 million (1,695,900 shares) were repurchased in the years ended December 31, 2006, 2005 and 2004, respectively.

(F) Kinder Morgan Energy Partners' Common Units

On February 14, 2007, Kinder Morgan Energy Partners paid a quarterly distribution of $0.83 per common unit for the quarterly period ended December 31, 2006, of which $123.2 million was paid to the public holders of Kinder Morgan Energy Partners' common units. The distributions were declared on January 17, 2007, payable to unitholders of record as of January 31, 2007. See Note 1(X) for additional information regarding our minority interests.

In August 2006, Kinder Morgan Energy Partners issued, in a public offering, 5,750,000 common units, including common units sold pursuant to an underwriters' over-allotment option, at a price of $44.80 per unit, less commissions and underwriting expenses. Kinder Morgan Energy Partners received net proceeds of approximately $248.0 million for the issuance of these 5,750,000 common units.

(G) Kinder Morgan Management, LLC

On November 10, 2004, Kinder Morgan Management closed the issuance and sale of 1,300,000 listed shares in a privately negotiated transaction with a single purchaser. None of the shares in the offering were purchased by us. Kinder Morgan Management used the net proceeds of approximately $52.6 million from the offering to buy additional i-units from Kinder Morgan Energy Partners. Additional information concerning the business of, and our obligations to, Kinder Morgan Management is contained in Kinder Morgan Management's 2006 Annual Report on Form 10-K.

On March 25, 2004, Kinder Morgan Management closed the issuance and sale of 360,664 listed shares in a privately negotiated transaction with a single purchaser. None of the shares in the offering were purchased by us. Kinder Morgan Management used the net proceeds of approximately $14.9 million from the offering to buy additional i-units from Kinder Morgan Energy Partners.

11. Preferred Stock

We have authorized 200,000 shares of Class A and 2,000,000 shares of Class B preferred stock, all without par value. At December 31, 2006, 2005 and 2004, we did not have any outstanding shares of preferred stock.

On September 15, 2005, a rights agreement dated August 21, 1995 expired. In connection with this agreement, we had designated 150,000 shares of our Class B Preferred Stock as Class B Junior Participating Series Preferred Stock. No shares of the Class B Junior Participating Series Preferred Stock were outstanding or had been issued, and none will be issued. On October 20, 2005, after the approval of the Board of Directors, we filed a certificate with the State of Kansas eliminating from our restated articles of incorporation, as amended, all reference to our Class B Junior Participating Series Preferred Stock. The 150,000 shares previously designated as Class B Junior Participating Series Preferred Stock have been restored to the status of authorized and unissued shares of Class B Preferred Stock, undesignated as to series.

12. Risk Management

We are exposed to risks associated with changes in the market price of natural gas, natural gas liquids and crude oil as a result of the forecasted purchase or sale of these products. We have exposure to interest rate risk as a result of the issuance of variable and fixed rate debt and commercial paper and to foreign currency risk from our investments in businesses owned and operated outside the United States. Pursuant to our management's risk management policy, we engage in derivative transactions for the purpose of mitigating these risks, which transactions are accounted for in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* and associated amendments ("SFAS No. 133").

Commodity Price Risk Management

We enter into derivative contracts solely for the purpose of hedging exposures that accompany our normal business activities.

In accordance with the provisions of SFAS No. 133, we designated these instruments as hedges of various exposures as discussed following, and we test the effectiveness of changes in the value of these hedging instruments with the risk being hedged. Hedge ineffectiveness is recognized in income in the period in which it occurs. Our over-the-counter swaps and options are entered into with counterparties outside central trading facilities such as a futures, options or stock exchange. These contracts are with a number of parties all of which have investment grade credit ratings. While we enter into derivative transactions principally with investment grade counterparties and actively monitor their ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future.

Our normal business activities expose us to risks associated with changes in the market price of natural gas, natural gas liquids and crude oil. Specifically, these risks are associated with (i) pre-existing or anticipated physical natural gas, natural gas liquids and crude oil sales, (ii) natural gas purchases and (iii) natural gas system use and storage. Apart from our derivatives for retail distribution gas supply contracts under Terasen Gas, during the three years ended December 31, 2006, all of our derivative activities relating to the mitigation of these risks were designated and qualified as cash flow hedges in accordance with SFAS No. 133. We recognized a pre-tax gain of approximately $5.9 million (net of minority interest loss of $0.2 million) in 2006 and pre-tax losses of $3.5 million and $1.4 million in 2005 and 2004, respectively, as a result of ineffectiveness of these hedges, which amounts are reported within the captions "Natural Gas Sales," "Oil and Product Sales" and "Gas Purchases and Other Costs of Sales" in the accompanying Consolidated Statements of Operations. There was no component of these derivatives instruments' gain or loss excluded from the assessment of hedge effectiveness.

As to our retail gas distribution operations under Terasen Gas, any differences between the effective cost of natural gas purchased and the price of natural gas included in rates are recorded in deferral accounts, and subject to regulatory approval, are passed through in future rates to customers. Terasen Gas' price risk management strategy covers a term of 36 months and aims to (i) improve the likelihood that natural gas prices remain competitive with electricity rates, (ii) dampen price volatility on customer rates and (iii) reduce the risk of regional price disconnects. The accompanying Balance Sheet at December 31, 2006 includes a net deferral of $119.9 million included in the caption "Current Assets: Rate Stabilization" representing net gains as a result of ineffectiveness of these hedges that are refundable to customers through rates.

As hedged sales and purchases take place and we record them into earnings, we also reclassify the gains and losses included in accumulated other comprehensive income into earnings. During 2006, 2005 and 2004, we reclassified $21.7 million (net of minority interest of $61.6 million), $102.3 million (net of minority interest of $64.8 million) and $38.0 million (net of minority interest of $22.9 million) respectively, of accumulated other comprehensive loss into earnings, as a result of hedged forecasted transactions occurring during the periods. During 2006, we reclassified $2.9 million of net losses into earnings as a result of the discontinuance of cash flow hedges due to a determination that the forecasted transactions would no longer occur by the end of the originally specified time period. We expect to reclassify approximately $15.2 million (net of minority interest of $49.1 million) of accumulated other comprehensive loss as of December 31, 2006 to earnings during the next twelve months. In conjunction with these activities, we are required to place funds in margin accounts or post letters of credit when the market value of these derivatives with specific counterparties exceeds established limits, or in conjunction with the purchase of exchange-traded derivatives. At December 31, 2006, our margin requirements associated with our commodity contract positions and over-the-counter swap partners totaled $28.0 million and is reported within the caption "Current Liabilities: Other." As of December 31, 2005, we had no cash margin deposits associated with our commodity contract positions and over-the-counter swap partners. As of December 31, 2006 and 2005, we had four outstanding letters of credit totaling $272 million and three outstanding letters of credit totaling approximately $44 million, respectively, in support of our hedging of commodity price risks associated with the sale of natural gas, natural gas liquids and crude oil.

Derivative instruments are entered into for the purpose of mitigating commodity price risk include swaps, futures and options. The fair values of these derivative contracts reflect the amounts that we would receive or pay to terminate the contracts at the reporting date and are included in the accompanying Consolidated Balances Sheets as of December 31, 2006 and 2005 within the captions indicated in the following table:

	December 31, 2006	December 31, 2005
	(In millions)	
Derivatives Asset (Liability)		
Current Assets: Other	$ 133.6	$ 151.2
Current Assets: Assets Held for Sale	9.0	-
Deferred Charges and Other Assets	13.8	1.3
Assets Held for Sale, Non-current	0.1	-
Current Liabilities: Other	(556.9)	(78.9)
Current Liabilities: Liabilities Held for Sale	(18.0)	-
Other Liabilities and Deferred Credits: Other	(510.2)	(0.8)
Other Liabilities and Deferred Credits: Liabilities Held for Sale, Non-current	(0.1)	-

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Given our portfolio of businesses as of December 31, 2006, our principal use of energy commodity derivative contracts was to mitigate the risk associated with market movements in the price of energy commodities. Our net short natural gas derivatives position primarily represented our hedging of anticipated future natural gas purchases and sales. Our net short crude oil derivatives position represented our crude oil derivative purchases and sales made to hedge anticipated oil purchases and sales. Finally, our net short natural gas liquids derivatives position reflected the hedging of our forecasted natural gas liquids purchases and sales. As of December 31, 2006, the maximum length of time over which we have hedged our exposure to the variability in future cash flows associated with commodity price risk is through December 2011.

Following is selected information concerning our energy commodity derivative contracts and over-the- counter swaps and options, excluding Terasen, as of December 31, 2006:

	Commodity Contracts	Over the Counter Swaps and Options Contracts	Total
		(Number of contracts[1])	
Natural Gas			
Notional Volumetric Positions: Long	164	2,351	2,515
Notional Volumetric Positions: Short	(2,132)	(2,342)	(4,474)
Net Notional Totals to Occur in 2007	(1,968)	(110)	(2,078)
Net Notional Totals to Occur in 2008 and Beyond	-	118	118
Crude Oil			
Notional Volumetric Positions: Long	-	2,985	2,985
Notional Volumetric Positions: Short	-	(55,835)	(55,835)
Net Notional Totals to Occur in 2007	-	(11,963)	(11,963)
Net Notional Totals to Occur in 2008 and Beyond	-	(40,887)	(40,887)
Natural Gas Liquids			
Notional Volumetric Positions: Long	-	10	10
Notional Volumetric Positions: Short	-	(360)	(360)
Net Notional Totals to Occur in 2007	-	(350)	(350)
Net Notional Totals to Occur in 2008 and Beyond	-	-	-

[1] A term of reference describing a unit of commodity trading. One natural gas contract equals 10,000 MMBtus. One crude oil or natural gas liquids contract equals 1,000 barrels.

Our over-the-counter swaps and options are with a number of parties, each of which is an investment grade credit. At December 31, 2006, based on the fair values of open positions, if parties to the derivative instruments failed completely to perform, our maximum amount of credit risk was $12.1 million.

Following is selected information concerning natural gas risk management activities of Terasen Gas where the natural gas commodity price risk is passed to the customer through future rates.

	Commodity Contracts	Over the Counter Swaps and Options Contracts	Total
		(Number of contracts[1])	
Natural Gas			
Notional Volumetric Positions: Long	-	82	82
Notional Volumetric Positions: Short	-	(10)	(10)
Net Notional Totals to Occur in 2007	-	42	42
Net Notional Totals to Occur in 2008 and Beyond	-	30	30

[1] A term of reference describing a unit of commodity trading. One natural gas contract equals 10,000 MMBtus.

Terasen Gas is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Terasen Gas deals with high credit quality institutions in accordance with established credit approval practices. At December 31, 2006, if parties to the derivative instruments failed to completely perform, our maximum amount of credit risk was $0.1 million.

Interest Rate Risk Management

We have exposure to interest rate risk as a result of the issuance of variable and fixed rate debt and commercial paper. We enter into interest rate swap agreements to mitigate our exposure to changes in the fair value of our fixed rate debt agreements.

These hedging relationships are accounted for under SFAS No. 133 using the "short-cut" method prescribed for qualifying fair value hedges. Accordingly, the carrying value of the swap is adjusted to its fair value as of the end of each reporting period, and an offsetting entry is made to adjust the carrying value of the debt securities whose fair value is being hedged. The fair value of the swaps of $106.6 million and $58.6 million at December 31, 2006 is included in the accompanying Consolidated Balance Sheet within the captions "Deferred Charges and Other Assets" and "Other Liabilities and Deferred Credits: Other," respectively. We record interest expense equal to the floating rate payments, which is accrued monthly and paid semi-annually.

On February 24, 2006, Terasen terminated their fixed-to-floating interest rate swap agreements associated with their 6.30% and 5.56% Medium Term Notes due 2008 and 2014, respectively, with a notional value of C$195 million, and received proceeds of $1.9 million (C$2.2 million). The cumulative loss recognized of $2.0 million (C$2.3 million) upon early termination of these fair value hedges was recorded under the caption "Long-term Debt: Value of Interest Rate Swaps" in the accompanying Consolidated Balance Sheet at December 31, 2006 and is being amortized to earnings over the original period of the swap transactions. Additionally, Terasen entered into two new interest rate swap agreements with a notional value of C$195 million. These new swaps have also been designated as fair value hedges and qualify for the "shortcut" method of accounting prescribed for qualifying hedges under SFAS No. 133.

On February 10, 2006, we entered into three fixed-to-floating interest rate swap agreements with notional principal amounts of $375 million, $425 million and $275 million, respectively. These swaps effectively convert 50% of the interest expense associated with Kinder Morgan Finance Company, ULC's 5.35% Senior Notes due 2011, 5.70% Senior Notes due 2016 and 6.40% Senior Notes due 2036, respectively, from fixed rates to floating rates based on the three-month LIBOR plus a credit spread. These swaps have been designated as fair value hedges and are accounted for utilizing the "shortcut" method prescribed for qualifying fair value hedges under SFAS No. 133.

On March 10, 2005, we terminated $250 million of our interest rate swap agreements associated with our 6.50% Senior Notes due 2012 and paid $3.5 million in cash. We are amortizing this amount to interest expense over the period the 6.50% Notes are outstanding. The unamortized balance of $2.7 million at December 31, 2006 is included in the caption "Long-term Debt: Value of Interest Rate Swaps" in the accompanying Consolidated Balance Sheet.

As of December 31, 2006 we had outstanding the following interest rate swap agreements that qualify for fair value hedge accounting under SFAS No. 133:

(i) fixed-to-floating interest rate swap agreements with notional principal amounts of $375 million, $425 million and $275 million, respectively. These swaps effectively convert 50% of the interest expense associated with Kinder Morgan Finance Company, ULC's 5.35% Senior Notes due 2011, 5.70% Senior Notes due 2016 and 6.40% Senior Notes due 2036, respectively, from fixed rates to floating rates,

(ii) fixed-to-floating interest rate swap agreements at Terasen, with a notional principal amount of C$195 million, which effectively convert a majority of its 6.30% and 5.56% Medium Term Notes due December 2008 and September 2014, respectively, from fixed rates to floating rates,

(iii) fixed-to-floating interest rate swap agreements, which effectively convert the interest expense associated with our 7.25% Debentures due in 2028 and our 6.50% Senior Notes due in 2012 from fixed to floating rates with a combined notional principal amount of $1.25 billion,

(iv) fixed-to-floating interest rate swap agreements under Kinder Morgan Energy Partners having a combined notional principal amount of $2.1 billion which effectively convert the interest expense associated with the following series of its senior notes from fixed rates to floating rates:

- $200 million principal amount of its 5.35% senior notes due August 15, 2007;
- $250 million principal amount of its 6.30% senior notes due February 1, 2009;
- $200 million principal amount of its 7.125% senior notes due March 15, 2012;
- $250 million principal amount of its 5.0% senior notes due December 15, 2013;
- $200 million principal amount of its 5.125% senior notes due November 15, 2014;
- $300 million principal amount of its 7.40% senior notes due March 15, 2031;
- $200 million principal amount of its 7.75% senior notes due March 15, 2032;

- $400 million principal amount of its 7.30% senior notes due August 15, 2033; and
- $100 million principal amount of its 5.80% senior notes due March 15, 2035.

As of December 31, 2006, we had outstanding the following interest rate swap agreements that are not designated as fair value hedges; however the interest costs or changes in fair values of the underlying swaps is ultimately recoverable or payable to customers or shippers. As a result, gains or losses resulting from these derivative instruments are deferred in the accompanying Consolidated Balance Sheet in the captions "Deferred Charges and Other Assets" or "Other Liabilities and Deferred Credits: Other," respectively. The fair value of these derivatives of $1.9 million at December 31, 2006 is included in the caption "Other Liabilities and Deferred Credits: Other" in the accompanying Consolidated Balance Sheet.

(i) Terasen Gas Inc. has floating-to-fixed interest rate swap agreements, with a notional principal amount of approximately C$49 million, which effectively convert its floating rate commercial paper to fixed rates in order to stabilize certain interest costs in the cost of service model approved by the regulatory authorities. These interest rate swaps will mature in November 2007.

(ii) TGVI has floating-to-fixed interest rate swap agreements, with a notional principal amount of C$65 million, which effectively convert its floating rate long-term bank debt to fixed rates in order to stabilize interest costs in the cost of service model approved by the regulatory authorities. The interest rate swaps will mature in October and November of 2008.

(iii) Terasen Pipelines (Corridor) Inc. has fixed-to-floating interest rate swap agreements, with a notional principal amount of C$300 million, which effectively convert interest expense associated with its 4.24% and 5.033% Debentures due February 2010 and February 2015, respectively, from fixed to floating rates.

Net Investment Hedges

We are exposed to foreign currency risk from our investments in businesses owned and operated outside the United States. To hedge the value of our investment in Canadian operations, we have entered into various cross-currency interest rate swap transactions that have been designated as net investment hedges in accordance with SFAS No. 133. We have recognized no ineffectiveness through the income statement as a result of these hedging relationships during 2006. The effective portion of the changes in fair value of these swap transactions are reported as a cumulative translation adjustment in the caption "Accumulated Other Comprehensive Loss" in the accompanying Consolidated Balance Sheet. The fair value of the swaps as of December 31, 2006 is a liability of $69.7 million which is included in the caption "Other Liabilities and Deferred Credits: Other" in the accompanying Consolidated Balance Sheet.

In December 2005 we entered into three receive-fixed-rate, pay-fixed-rate U.S. dollar to Canadian dollar cross-currency interest rate swap agreements. These derivative instruments have a combined notional value of C$1,240 million and have been designated as a hedge of our net investment in Canadian operations in accordance with Statement 133.

In December 2005 we entered into three receive-fixed-rate, pay-variable-rate U.S. dollar to Canadian dollar cross-currency interest rate swap agreements. These agreements had a combined notional value of C$1,254 million and did not qualify as a hedge of our net investment in Canadian Operations in accordance with SFAS No. 133. In February 2006 we entered into a series of transactions to effectively terminate these agreements and entered into a series of receive-fixed-rate, pay-fixed-rate U.S. dollar to Canadian dollar cross-currency interest rate swap agreements with a combined notional value of C$1,254 million. The new derivative instruments have been designated as hedges of our net investment in Canadian operations in accordance with SFAS No. 133. We recognized a one time non-cash, after-tax loss of approximately $14 million in the first quarter of 2006 from changes in the fair value of our receive-fixed-rate, pay-variable rate U.S. dollar to Canadian dollar cross-currency interest rate swaps from January 1, 2006 to the termination of the agreements to reflect the strengthening of the Canadian dollar versus the U.S. dollar.

13. Employee Benefits

On September 29, 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of FASB Statement Nos. 87, 88, 106 and 132(R)* ("SFAS No. 158"). This statement requires a company to recognize the overfunded or underfunded status of its defined benefit pension and postretirement plans as assets or liabilities in its statement of financial position. The statement also requires a company to recognize as a component of other comprehensive income the gains or losses and prior service costs or credits that arise during a period but that are not recognized as part of net periodic benefit costs in the current period.

We have adopted the provisions of SFAS No. 158 as of December 31, 2006. The incremental effect on individual line items in our Consolidated Balance Sheet as a result of the application of SFAS No. 158 is as follows:

	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
		(In millions)	
Consolidated Balance Sheet Caption at December 31, 2006:			
Investments: Other	$ 1,093.3	$ (8.7)	$ 1,084.6
Deferred Charges and Other Assets	$ 1,108.6	$ (42.3)	$ 1,066.3
Total Assets	$ 26,846.6	$ (51.0)	$ 26,795.6
Current Liabilities: Other	$ 841.0	$ (1.0)	$ 840.0
Other Liabilities and Deferred Credits: Deferred Income Taxes	$ 3,170.8	$ (26.8)	$ 3,144.0
Other Liabilities and Deferred Credits: Other	$ 1,323.1	$ 26.3	$ 1,349.4
Minority Interests in Equity of Subsidiaries	$ 3,098.2	$ (2.7)	$ 3,095.5
Accumulated Other Comprehensive Loss	$ (89.1)	$ (46.8)	$ (135.9)
Total Stockholders' Equity	$ 3,568.4	$ (46.8)	$ 3,521.6
Total Liabilities and Stockholders' Equity	$ 26,846.6	$ (51.0)	$ 26,795.6

Following are separate discussions of our pension and postretirement benefit plans, and those of our consolidated subsidiaries.

Kinder Morgan, Inc.

(A) Retirement Plans

We have defined benefit pension plans covering eligible full-time employees. These plans provide pension benefits that are based on the employees' compensation during the period of employment, age and years of service. These plans are tax-qualified subject to the minimum funding requirements of the *Employee Retirement Income Security Act of 1974,* as amended. Our funding policy is to contribute annually the recommended contribution using the actuarial cost method and assumptions used for determining annual funding requirements. Plan assets consist primarily of pooled fixed income, equity, bond and money market funds. Plan assets included our common stock valued at $32.0 million as of December 31, 2005. The Plan did not have any investment in our common stock as of December 31, 2006.

Total amounts recognized in net periodic pension cost include the following components:

	Year Ended December 31,		
	2006	2005	2004
Net Periodic Pension Benefit Cost:		(In millions)	
Service Cost	$ 10.6	$ 9.6	$ 8.6
Interest Cost	12.7	12.1	11.6
Expected Return on Assets	(21.3)	(20.2)	(16.3)
Amortization of Transition Asset	-	(0.1)	(0.2)
Amortization of Prior Service Cost	0.2	0.2	0.2
Amortization of Loss	0.9	0.6	0.2
Net Periodic Pension Benefit Cost	$ 3.1	$ 2.2	$ 4.1

The following table sets forth the reconciliation of the beginning and ending balances of the pension benefit obligation:

	2006	2005
	(In millions)	
Benefit Obligation at Beginning of Year	$ 224.5	$ 204.9
Service Cost	10.6	9.6
Interest Cost	12.7	12.1
Actuarial Loss (Gain)	(4.3)	8.5
Business Combinations/Mergers	0.2	-
Benefits Paid	(11.7)	(10.6)
Benefit Obligation at End of Year	$ 232.0	$ 224.5

The accumulated benefit obligation through December 31, 2006 and 2005 was $220.6 million and $212.7 million, respectively.

The following table sets forth the reconciliation of the beginning and ending balances of the fair value of the plans' assets and the plans' funded status:

	December 31, 2006	December 31, 2005
	(In millions)	
Fair Value of Plan Assets at Beginning of Year	$ 242.4	$ 206.6
Actual Return on Plan Assets During the Year	30.7	21.4
Contributions by Employer	-	25.0
Benefits Paid During the Year	(11.7)	(10.6)
Business Combinations/Mergers	0.2	-
Fair Value of Plan Assets at End of Year	261.6	242.4
Benefit Obligation at End of Year	(232.0)	(224.5)
Funded Status at End of Year	$ 29.6	$ 17.9

The accompanying Consolidated Balance Sheets at December 31, 2006 and 2005 include balances of $28.2 million and $52.0 million, respectively, related to our pension plans under the caption "Deferred Charges and Other Assets." Amounts recognized in Accumulated Other Comprehensive Loss due to the initial application of SFAS No. 158 at December 31, 2006 consist of:

	December 31, 2006
	(In millions)
Net Loss	$ 19.6
Prior Service Cost	1.5
	$ 21.1

The estimated prior service cost and net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic pension benefit cost over the next fiscal year are $0.2 million and less than $0.1 million, respectively.

We do not expect to contribute to the Plan during 2007.

The following net benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Fiscal Year	Expected Net Benefit Payments
	(In millions)
2007	$ 12.3
2008	$ 12.8
2009	$ 14.1
2010	$ 15.1
2011	$ 16.6
2012-2016	$ 102.5

Effective January 1, 2001, we added a cash balance plan to our retirement plan. Certain collectively bargained employees and "grandfathered" employees continue to accrue benefits through the defined pension benefit plan described above. All other employees accrue benefits through a personal retirement account in the cash balance plan. All employees converting to the cash balance plan were credited with the current fair value of any benefits they had previously accrued through the defined benefit plan. We make contributions on behalf of these employees equal to 3% of eligible compensation every pay period. In addition, we may make discretionary contributions to the plan based on our performance. No discretionary contributions were made for 2006 performance. Interest is credited to the personal retirement accounts at the 30-year U.S. Treasury bond rate, or an approved substitute, in effect each year. Employees become fully vested in the plan after five years, and they may take a lump sum distribution upon termination of employment or retirement.

In addition to our retirement plan described above, we have the Kinder Morgan, Inc. Savings Plan (the "Plan"), a defined contribution 401(k) plan. The plan permits all full-time employees to contribute between 1% and 50% of base compensation, on a pre-tax basis, into participant accounts. In addition to a mandatory contribution equal to 4% of base compensation per year for most plan participants, we may make discretionary contributions in years when specific performance objectives are met. Certain employees' contributions are based on collective bargaining agreements. The mandatory contributions are made each pay period on behalf of each eligible employee. Any discretionary contributions are generally made during the first quarter following the performance year. All employer contributions, including discretionary contributions, are in the form of Company stock, which is immediately convertible into other available investment vehicles at the employee's discretion. Our Board of Directors has authorized a total of 6.7 million shares to be issued through the Plan. The total amount contributed for 2006, 2005 and 2004 was $18.3 million, $14.6 million and $12.2 million, respectively.

For employees hired on or prior to December 31, 2004, all contributions, together with earnings thereon, are immediately vested and not subject to forfeiture. Employer contributions for employees hired on or after January 1, 2005 will vest on the second anniversary of the date of hire. Effective October 1, 2005, for new employees of Kinder Morgan Energy Partners, L.P.'s Terminals segment, a tiered employer contribution schedule was implemented. This tiered schedule provides for employer contributions of 1% for service less than one year, 2% for service between one and two years, 3% for services between two and five years, and 4% for service of five years or more. All employer contributions for Terminal employees hired after October 1, 2005 will vest on the fifth anniversary of the date of hire. Vesting and contributions for bargaining employees will follow the collective bargaining agreements.

At its July 2005 meeting, the compensation committee of our board of directors approved a special contribution of an additional 1% of base pay into the Savings Plan for each eligible employee. Each eligible employee received an additional 1% company contribution based on eligible base pay each pay period beginning with the first pay period of August 2005 and continuing through the last pay period of July 2006. At its July 2006 meeting, the compensation committee again approved a 1% additional contribution beginning with the first pay period of August 2006 and continuing through the last pay period of July 2007. The additional 1% contribution is in the form of Company stock (the same as the current 4% contribution) and does not change or otherwise impact, the annual 4% contribution that eligible employees currently receive. It may be converted to any other Savings Plan investment fund at any time and the vesting schedule mirrors the company's 4% contribution. Since this additional 1% company contribution is discretionary, compensation committee approval will be required annually for each additional contribution. During the first quarter of 2007, excluding the 1% additional contribution described above, we will not make any additional discretionary contributions to individual accounts for 2006.

(B) Other Postretirement Employee Benefits

We have a postretirement plan providing medical and life insurance benefits upon retirement for eligible employees and their eligible dependents. We fund a portion of the future expected postretirement benefit cost under the plan by making payments to Voluntary Employee Benefit Association trusts. Plan assets are invested in a mix of equity funds and fixed income instruments similar to the investments in our pension plans.

Total amounts recognized in net periodic postretirement benefit cost includes the following components:

	Year Ended December 31,		
	2006	**2005**	**2004**
		(In millions)	
Net Periodic Postretirement Benefit Cost:			
Service Cost	$ 0.4	$ 0.4	$ 0.4
Interest Cost	4.9	5.3	5.6
Expected Return on Assets	(5.8)	(5.7)	(5.2)
Amortization of Prior Service Credit	(1.6)	(1.7)	(1.7)
Amortization of Loss	5.2	5.0	4.9
Net Periodic Postretirement Benefit Cost	$ 3.1	$ 3.3	$ 4.0

The following table sets forth the reconciliation of the beginning and ending balances of the accumulated postretirement benefit obligation:

	2006	2005
	(In millions)	
Benefit Obligation at Beginning of Year	$ 89.8	$ 91.9
Service Cost	0.4	0.4
Interest Cost	4.9	5.3
Actuarial Loss (Gain)	(3.5)	1.4
Benefits Paid	(10.8)	(13.1)
Retiree Contributions	2.7	3.9
Plan Amendments	0.5	-
Benefit Obligation at End of Year	$ 84.0	$ 89.8

The following table sets forth the reconciliation of the beginning and ending balances of the fair value of plan assets and the plan's funded status:

	December 31,	
	2006	2005
	(In millions)	
Fair Value of Plan Assets at Beginning of Year	$ 59.4	$ 60.1
Actual Return on Plan Assets	7.2	2.0
Contributions by Employer	8.7	8.5
Retiree Contributions	2.7	3.9
Transfers In	-	0.2
Benefits Paid	(10.5)	(15.3)
Fair Value of Plan Assets at End of Year	67.5	59.4
Benefit Obligation at End of Year	(84.0)	(89.8)
Funded Status at End of Year	$ (16.5)	$ (30.4)

Amounts recognized in the consolidated balance sheets are as follows:

	December 31,	
	2006	2005
	(In millions)	
Non-current Assets	$ -	$ 21.9
Non-current Liabilities	(16.9)	-
	$ (16.9)	$ 21.9

Amounts recognized in Accumulated Other Comprehensive Loss due to the initial application of SFAS No. 158 at December 31, 2006 consist of:

	December 31, 2006
	(In millions)
Net Loss	$ 60.2
Prior Service Credit	(15.8)
	$ 44.4

The estimated net loss and prior service cost for the postretirement benefit plans that will be amortized from accumulated other comprehensive income into net periodic postretirement benefit cost over the next fiscal year are $4.8 million and $(1.6) million, respectively.

We expect to make contributions of approximately $8.7 million to the plan in 2007.

A one-percentage-point increase (decrease) in the assumed health care cost trend rate for each future year would have increased (decreased) the aggregate of the service and interest cost components of the 2006 net periodic postretirement benefit cost by approximately $5 (5) thousand and would have increased (decreased) the accumulated postretirement benefit obligation as of December 31, 2006 by approximately $78 (73) thousand.

The following net benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Fiscal Year	Expected Net Benefit Payments
	(In millions)
2007	$ 7.6
2008	$ 7.3
2009	$ 7.1
2010	$ 6.1
2011	$ 6.8
2012-2016	$ 31.6

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 ("the Act") was signed into law. In January 2004, the FASB issued Staff Position ("FSP") FAS 106-1, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003,* to provide guidance on accounting and disclosure for the Act as it pertains to postretirement benefit plans, and in May 2004, the FASB issued FSP FAS 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003,* which superseded FSP FAS 106-1 effective July 1, 2004, which provides specific authoritative guidance on the accounting for the federal subsidy included in the Act. In the third quarter of 2004, our board approved a resolution to amend our postretirement benefit plan to eliminate prescription drug benefits for Medicare eligible retirees effective January 1, 2006, which eliminates any potential effects on our periodic postretirement benefit costs due to the federal subsidy included in the Act.

(C) Actuarial Assumptions

The assumptions used to determine benefit obligations for the pension and postretirement benefit plans were:

	December 31,		
	2006	2005	2004
Discount Rate	6.00%	5.75%	6.00%
Expected Long-term Return on Assets	9.00%	9.00%	9.00%
Rate of Compensation Increase (Pension Plan Only)	3.50%	3.50%	3.50%

The assumptions used to determine net periodic benefit cost for the pension and postretirement benefits were:

	Year Ended December 31,		
	2006	2005	2004
Discount Rate	5.75%	6.00%	6.50%
Expected Long-term Return on Assets	9.00%	9.00%	9.00%
Rate of Compensation Increase (Pension Plan Only)	3.50%	3.50%	3.50%

The assumed healthcare cost trend rates for the postretirement plan were:

	December 31,		
	2006	2005	2004
Healthcare Cost Trend Rate Assumed for Next Year	3.0%	3.0%	3.0%
Rate to which the Cost Trend Rate is Assumed to Decline (Ultimate Trend Rate)	3.0%	3.0%	3.0%
Year the Rate Reaches the Ultimate Trend Rate	2006	2005	2004

(D) Plan Investment Policies

The investment policies and strategies for the assets of our pension and retiree medical and retiree life insurance plans are established by the Fiduciary Committee (the "Committee"), which is responsible for investment decisions and management oversight of each plan. The stated philosophy of the Committee is to manage these assets in a manner consistent with the purpose for which the plans were established and the time frame over which the plans' obligations need to be met. The objectives of the investment management program are to (1) meet or exceed plan actuarial earnings assumptions over the long term and (2) provide a reasonable return on assets within established risk tolerance guidelines and liquidity needs of the plans with the goal of paying benefit and expense obligations when due. In seeking to meet these objectives, the Committee recognizes that prudent investing requires taking reasonable risks in order to raise the likelihood of achieving the targeted investment returns. In order to reduce portfolio risk and volatility, the Committee has adopted a strategy of using multiple asset classes.

As of December 31, 2006, the following target asset allocation ranges were in effect for our pension plans (Minimum/Target/Maximum): Cash – 0%/0%/5%; Fixed Income – 20%/30%/40% and Equity – 65%/70%/80%. As of December 31, 2006, the following target asset allocation ranges were in effect for our retiree medical and retiree life insurance plans (Minimum/Target/Maximum): Cash – 0%/5%/15%; Fixed Income – 15%/25%/35% and Equity – 60%/70%/80%. In order to achieve enhanced diversification, the equity category is further subdivided into sub-categories with respect to small cap vs. large cap, value vs. growth and international vs. domestic, each with its own target asset allocation. Historically, our plans have allowed for up to 15% of the plans' assets to be held in Kinder Morgan stock. During the fourth quarter of 2006, all investments in Kinder Morgan, Inc. stock held by the plans were systematically liquidated at the discretion of our independent fiduciary. As a result of the sale of these assets, at December 31, 2006, the cash position in our pension plan was above the maximum range and the equity position was below the minimum range. In the first quarter of 2007, the Committee will meet to reevaluate the target asset allocation ranges and rebalance the plans' portfolios.

In implementing its investment policies and strategies, the Committee has engaged a professional investment advisor to assist with its decision making process and has engaged professiona l money managers to manage plan assets. The Committee believes that such active investment management will achieve superior returns with comparable risk in comparison to passive management. Consistent with its goal of reasonable diversification, no manager of an equity portfolio for the plan is allowed to have more than 10% of the market value of the portfolio in a single security or weight a single economic sector more than twice the weighting of that sector in the appropriate market index. Finally, investment managers are not permitted to invest or engage in the following equity transactions unless specific permission is given in writing (which permission has not been requested or granted by the Committee to-date): derivative instruments, except for the purpose of asset value protection (such as writing covered calls), direct ownership of letter stock, restricted stock, limited partnership units (unless the security is registered and listed on a domestic exchange), venture capital, short sales, margin purchases or borrowing money, stock loans and commodities. In addition, fixed income holdings in the following investments are prohibited without written permission: private placements, except medium-term notes and securities issued under SEC Rule 144a; foreign bonds (non-dollar denominated); municipal or other tax exempt securities, except taxable municipals; margin purchases or borrowing money to effect leverage in the portfolio; inverse floaters, interest only and principle only mortgage structures; and derivative investments (futures or option contracts) used for speculative purposes. Certain other types of investments such as hedge funds and land purchases are not prohibited as a matter of policy but have not, as yet, been adopted as an asset class or received any allocation of fund assets.

(E) Return on Plan Assets

For the year ending December 31, 2006, our defined benefit pension plan yielded a weighted-average rate of return of 13.25%, above the expected rate of return on assets of 9.00%. Investment performance for a balanced fund comprised of a similar mix of assets yielded a weighted-average return of 14.01%, so our plans slightly underperformed the benchmark balanced fund index. For the year ending December 31, 2006, our retiree medical and retiree life insurance plans yielded a weighted-average rate of return of 12.13%, above the expected rate of return on assets of 9.00%. Investment performance for a balanced fund comprised of a similar mix of assets yielded a weighted-average return of 13.58%, so our plans slightly underperformed the benchmark balanced fund index.

At December 31, 2006, our pension plan assets consisted of 59.9% equity, 24.5% fixed income and 15.6% cash and cash equivalents, and our retiree medical and retiree life insurance plan assets consisted of 63.8% equity, 25.7% fixed income and 10.5% cash and cash equivalents. Historically over long periods of time, widely traded large cap equity securities have provided a return of 10%, while fixed income securities have provided a return of 6%, indicating that a long term expected return predicated on the asset allocation as of December 31, 2006 would be approximately 8.8% to 9.2% if investments were made in the broad indexes. Therefore, we arrived at an overall expected return of 9% for purposes of making the required calculations.

Kinder Morgan Energy Partners

In connection with Kinder Morgan Energy Partners' acquisition of SFPP, L.P., referred to in this report as SFPP, and Kinder Morgan Bulk Terminals, Inc. in 1998, Kinder Morgan Energy Partners acquired certain liabilities for pension and postretirement benefits. Kinder Morgan Energy Partners provides medical and life insurance benefits to current employees, their covered dependents and beneficiaries of SFPP and Kinder Morgan Bulk Terminals. Kinder Morgan Energy Partners also provides the same benefits to former salaried employees of SFPP. Additionally, Kinder Morgan Energy Partners will continue to fund these costs for those employees currently in the plan during their retirement years. SFPP's postretirement benefit plan is frozen, and no additional participants may join the plan.

The noncontributory defined benefit pension plan covering the former employees of Kinder Morgan Bulk Terminals is the Kinder Morgan, Inc. Retirement Plan. The benefits under this plan are based primarily upon years of service and final average pensionable earnings; however, benefit accruals were frozen as of December 31, 1998. The net periodic benefit cost for the SFPP post-retirement benefit plan was a credit of $0.3 million in 2006. The credit resulted in an increase to income, largely due to amortizations of an actuarial gain and a negative prior service cost, primarily related to the following:

- there have been changes to the plan for both 2004 and 2005 which reduced liabilities, creating a negative prior service cost that is being amortized each year; and

- there was a significant drop in 2004 in the number of retired participants reported as pipeline retirees by Burlington Northern Santa Fe, which holds a 0.5% special limited partner interest in SFPP, L.P.

As of December 31, 2006, the estimated net periodic post-retirement benefit cost for the year 2007 will be a credit of approximately $0.3 million, including amortization of approximately $0.5 million of combined prior service credits and actuarial gains from accumulated other comprehensive income. Kinder Morgan Energy Partners expects to contribute approximately $0.4 million to the SFPP postretirement benefit plan in 2007.

Both the funded status and the recorded value of the benefit obligation for the SFPP post-retirement benefit plan as of December 31, 2006 was $5.5 million.

Multiemployer Plans

As a result of acquiring several terminal operations, primarily the acquisition of Kinder Morgan Bulk Terminals, Inc. effective July 1, 1998, Kinder Morgan Energy Partners participates in several multi-employer pension plans for the benefit of employees who are union members. Kinder Morgan Energy Partners does not administer these plans and contributes to them in accordance with the provisions of negotiated labor contracts. Other benefits include a self-insured health and welfare insurance plan and an employee health plan where employees may contribute for their dependents' health care costs. Amounts charged to expense for these plans totaled $6.3 million for the year ended December 31, 2006.

Terasen

We are a sponsor of pension plans for eligible employees. The plans include registered defined benefit pension plans, supplemental unfunded arrangements, which provide pension benefits in excess of statutory limits, and defined contributory plans. We also provide postretirement benefits other than pensions for retired employees. The following is a summary of each type of plan:

(A) Description of Plans

Defined Benefit Plans

Retirement benefits under the defined benefit plans are based on employees' years of credited service and remuneration. Company contributions to the plan are based upon independent actuarial valuations. The most recent actuarial valuations of the defined benefit pension plans for funding purposes were at December 31, 2005 and December 31, 2004, and the dates of the next required valuations are December 31, 2008 and December 31, 2007. The expected weighted average remaining service life of employees covered by the defined benefit pension plans is 10.8 years.

Effective January 1, 2007, all employees will become participants in a defined benefit pension plan in which costs are split evenly between the employee and employer. All current employees will be grandfathered in their respective plans and those plans will be closed to new members.

Defined Contribution Plan

Effective in 2000 for Terasen Gas and 2003 for petroleum transportation operations, all new non-union employees became members of defined contribution pension plans. Company contributions to the plan are based upon employee age and pensionable earnings for employees of the natural gas distribution operations and pensionable earnings for employees of the petroleum transportation operation. Effective January 1, 2007, this plan was frozen and all employees will become participants in the new defined benefit plan described above.

Supplemental Plans

Certain employees are eligible to receive supplemental benefits under both the defined benefit and defined contribution plans. The supplemental plans provide pension benefits in excess of statutory limits. The supplemental plans are unfunded and are secured by letters of credit. Beginning in 2006, we have capped eligible compensation for Canada-based employees at C$250,000 per year.

Other Postretirement Benefits

We provide retired employees with other postretirement benefits that include, depending on circumstances, supplemental health, dental and life insurance coverage. Postretirement benefits are unfunded and annual expense is recorded on an accrual basis based on independent actuarial determinations, considering among other factors, health care cost escalation. The most recent actuarial valuations were completed as of December 31, 2005 and the date of the next required valuation is December 31, 2008. The expected weighted average remaining service life of employees covered by these benefit plans is 9.9 years.

(B) Actuarial Valuations

The financial positions of the employee defined benefit pensio n plans and postretirement bene fit plans are presented in aggregate in the tables below.

Net periodic pension and postretirement costs include the following components:

	Year Ended December 31, 2006		Month Ended December 31, 2005	
	Pension Benefit Plans	Postretirement Benefit Plans	Pension Benefit Plans	Postretirement Benefit Plans
	(In millions)			
Service Cost	$ 7.7	$ 1.5	$ 0.7	$ 0.1
Interest Cost	14.8	3.6	1.2	0.3
Expected Return on Assets	(17.4)	-	(1.6)	-
Expense Load	0.1	0.1	-	-
Actuarial Loss	0.2	-	-	-
Special Termination Benefits	0.4	-	-	-
Net Periodic Pension Benefit Cost	$ 5.8	$ 5.2	$ 0.3	$ 0.4
Defined Contribution Cost	0.1	-	0.2	-
Total Benefit Expense	$ 5.9	$ 5.2	$ 0.5	$ 0.4

The following table sets forth the reconciliation of the beginning and ending balances of the pension and postretirement benefit obligation:

	Year Ended December 31, 2006		Month Ended December 31, 2005	
	Pension Benefit Plans	Postretirement Benefit Plans	Pension Benefit Plans	Postretirement Benefit Plans
	(In millions)			
Benefit Obligation at Beginning of Period	$ 296.1	$ 70.5	$ 284.6	$ 67.9
Change in Foreign Exchange Rates	(0.6)	(0.2)	-	-
Service Cost	7.7	1.5	0.7	0.1
Interest Cost	14.8	3.6	1.2	0.3
Change in Discount Rate	-	-	6.8	2.3
Actuarial Loss	11.5	3.0	3.3	-
Contributions by Members	2.9	-	0.3	-
Special Termination Benefits	0.4	-		
Benefits Paid	(15.3)	(1.5)	(0.8)	(0.1)
Benefit Obligation at End of Period	$ 317.5	$ 76.9	$ 296.1	$ 70.5

The accumulated pension benefit obligation through December 31, 2006 was $267.0 million.

The following table sets forth the reconciliation of the beginning and ending balances of the fair value of the plans' assets and the plans' funded status:

	Year Ended December 31, 2006		Month Ended December 31, 2005	
	Pension Benefit Plans	Postretirement Benefit Plans	Pension Benefit Plans	Postretirement Benefit Plans
	(In millions)			
Fair Value of Plan Assets at Beginning of Period	$ 256.7	$ –	$ 254.5	$ –
Change in Foreign Exchange Rates	(0.5)	–	–	–
Actual Return on Plan Assets During the Period	35.9	–	2.2	–
Contributions by Employer	7.6	1.6	0.5	0.1
Contributions by Members	2.9	–	0.3	–
Expense Load	(0.1)	(0.1)	–	–
Benefits Paid During the Period	(15.3)	(1.5)	(0.8)	(0.1)
Fair Value of Plan Assets at End of Year	$ 287.2	$ –	$ 256.7	$ –
Benefit Obligation at End of Year	(317.5)	(76.9)	(296.1)	(70.5)
Funded Status at End of Year	$ (30.3)	$ (76.9)	$ (39.4)	$ (70.5)

Amounts recognized in the consolidated balance sheets after application of SFAS No. 158 are as follows:

	December 31, 2006	
	Pension Benefit Plans	Postretirement Benefit Plans
	(In millions)	
Non-current Assets	$ 10.2	$ –
Non-current Liabilities	(40.5)	(76.9)
	$ (30.3)	$ (76.9)

Amounts in Accumulated Other Comprehensive Loss in the accompanying Consolidated Balance Sheet consist of:

	December 31, 2006	
	Pension Benefit Plans	Postretirement Benefit Plans
	(In millions)	
Net Loss (Gain)	$ 2.2	$ 5.4
Prior Service Cost (Credit)[1]	–	–
	$ 2.2	$ 5.4

[1] Net prior service credit for the pension benefit plan was less than $0.1 million at December 31, 2006.

The estimated net loss and prior service credit for the postretirement benefit plans that will be amortized from accumulated other comprehensive income into net periodic postretirement benefit cost over the next fiscal year are $0.5 million and less than $0.1 million, respectively.

For 2007, we expect to contribute approximately $8.5 million and $1.6 million to the pension and postretirement plans, respectively.

A one-percentage-point increase (decrease) in the assumed health care cost trend rate for each future year would have increased (decreased) the aggregate of the service and interest cost components of the 2006 net periodic postretirement benefit cost by approximately $0.7 million ($0.6 million) and would have increased (decreased) the accumulated postretirement benefit obligation as of December 31, 2006 by approximately $8.9 million ($8.0 million).

The following net benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Expected Net Benefit Payments	
Fiscal Year	Pension Benefit Plans	Postretirement Benefit Plans
	(In millions)	
2007	$ 14.1	$ 1.4
2008	$ 14.4	$ 1.4
2009	$ 14.7	$ 1.5
2010	$ 15.0	$ 1.6
2011	$ 15.6	$ 1.7
2012-2016	$ 89.0	$ 9.7

(C) Actuarial Assumptions

The assumptions used to determine benefit obligations for the pension and postretirement benefit plans were:

	December 31,	
	2006	2005
Discount Rate	5.00%	5.00%
Expected Long-term Return on Assets	7.25%	7.50%
Rate of Compensation Increase (Pension Plan Only)[1]	3.84%	3.50%

[1] Rate of compensation increase is for the next five years. Thereafter, the rate decreases to 3.50%.

The assumptions used to determine net periodic benefit cost for the pension and postretirement benefits were:

	Year Ended December 31, 2006	Month Ended December 31, 2005
Discount Rate	5.00%	5.25%
Expected Long-term Return on Assets	7.25%	7.50%
Rate of Compensation Increase (Pension Plan Only)	3.84%	3.50%

The assumed healthcare cost trend rates for the postretirement plan were:

	December 31,	
	2006	2005
Healthcare Cost Trend Rate Assumed for Next Year	10.0%	7.0%
Rate to which the Cost Trend Rate is Assumed to Decline (Ultimate Trend Rate)	5.0%	5.0%
Year the Rate Reaches the Ultimate Trend Rate	2011	2008

(D) Plan Investment Policies

The investment policy for benefit plan assets is to optimize the risk-return using a portfolio of various asset classes. Our primary investment objectives are to secure registered pension plans, and maximize investment returns in a cost-effective manner while not compromising the security of the respective plans. The pension plans utilize external investment managers to mange the investment policy. Assets in the plan are held in trust by independent third parties.

(E) Return on Plan Assets

For the year ending December 31, 2006, our defined benefit pension plans yielded a weighted-average rate of return of 13.29%, well above management's expected rate of return on assets of 7.25%. The expected long-term return on assets is determined by the long-term average market returns on a similar mix of investments and comparisons with other plans in Terasen's peer group. Investment performance for a median-indexed balanced fund comprised of a similar mix of assets yielded a weighted-average rate of return of 12.33%, so Terasen's plans slightly outperformed the balanced fund index. Terasen's target asset allocations for the various pension plans are 55% – 58% equity, 32% – 45% fixed income and 0% – 10% real estate and other investments. The asset mix at December 31, 2006 consisted of approximately 58% equity, 36% in fixed-income securities and 6% in real estate investments.

14. Share-based Compensation

Kinder Morgan, Inc.

We have stock options issued under the following plans: The 1992 Non-Qualified Stock Option Plan for Non-Employee Directors (which plan has expired), the 1994 Kinder Morgan, Inc. Long-term Incentive Plan (which plan has expired), the Kinder Morgan, Inc. Amended and Restated 1999 Stock Plan and the Non-Employee Directors Stock Awards Plan. The 1994 plan provided for, and the 1999 plan and the Non-Employee Directors Stock Awards Plan provide for the issuance of restricted stock. We also have two employee stock purchase plans, one for U.S. employees and one for Canada-based employees.

Over the years, the 1999 Stock Plan has been amended to increase shares available to grant, to allow for granting of restricted shares, and effective January 18, 2006 has been amended to allow for the granting of restricted stock units to employees residing outside the United States. The company stopped granting stock options after July 2004 and has replaced option grants with grants of restricted stock and restricted stock units to fewer people and in smaller amounts. Options granted prior to 2005 generally had vesting schedules of either 25% per year with a 10-year life or 100% after three years with a seven-year life. Our restricted stock and restricted stock unit grants generally have either a three-year or five-year cliff vesting.

During 2006, we recognized stock optio n expense of $5.0 million. At Decembe r 31, 2006, unrecognized compensation expense was approximately $0.8 million, all of which will be recognized during 2007.

During 2006, 2005 and 2004 we made restricted common stock grants to employees of 10,000, 223,940, and 167,350 shares, respectively. These grants are valued at $1.0 million, $20.2 million, and $10.2 million, respectively, based on the closing market price of our common stock on either the date of grant or the measurement date, if different. Restricted stock grants made to employees vest over three and five year periods. During 2006 and 2005, we made restricted common stock grants to our non-employee directors of 17,600 and 15,750, respectively. These grants are valued at $1.7 million and $1.1 million, respectively. All of the restricted stock grants made to non-employee directors vest during a six-month period. Expense related to restricted grants is recognized on a straight-line basis over the respective vesting periods. During 2006, 2005 and 2004, we amortized $14.9 million, $8.2 million and $5.1 million, respectively, related to restricted stock grants.

During 2006, we made restricted stock unit grants of 61,800 units. These grants are valued at $6.0 million, based on the closing market price of our common stock on either the date of grant or the measurement date, if different. Of the 61,800 restricted stock unit grants, 27,950 units vest one-third per year over a three-year period and the related expense is recognized on a graded basis over the vesting period and 33,850 units vest during a three-year period and the related expense is recognized on a straight-line basis over the vesting period. Upon vesting, the grants will be paid fifty percent in cash and fifty percent in our common shares. During 2006, we amortized $3.4 million related to restricted stock unit grants.

As required by the provision of SFAS No. 123R, we have eliminated the deferred compensation balance previously shown on our Consolidated Balance Sheet against the caption "Additional Paid-in Capital."

A summary of the status of our restricted stock and restricted stock unit plans at December 31, 2006, and changes during the year then ended is presented in the table below:

	Year Ended December 31, 2006	
	Shares	**Weighted Average Grant Date Fair Value (In millions)**
Outstanding at Beginning of Period	880,310	$ 56.6
Granted	89,400	8.7
Reinstated	50,000	2.7
Vested	(193,620)	(11.3)
Forfeited	(13,850)	(1.1)
Outstanding at End of Period	812,240	$ 55.6
Intrinsic Value of Restricted Stock Vested During the Period		$ 19.2

Contingent grants totaling an additional 178,000 shares of restricted common stock and 65,650 restricted stock units were granted in July 2006. These grants will only be effective if we do not execute the definitive merger agreement under which investors led by Richard D. Kinder, our Chairman and Chief Executive Officer, will acquire all of our outstanding common stock for $107.50 per share in cash (the "Going Private" transaction). If the Going Private transaction occurs, we plan to implement a replacement plan of similar value. During 2006, we amortized $1.9 million related to these contingent grants.

Under all plans, except the Long-term Incentive Plan, options must be granted at not less than 100% of the market value of the stock at the date of grant. The Long-term Incentive Plan has been terminated and therefore has no shares available for future grants.

Plan Name	Shares Subject to the Plan	Option Shares Granted Through December 31, 2006	Vesting Period	Expiration Period
1992 Directors' Plan....................	1,025,000	621,875	0 – 6 Months	10 Years
Long-term Incentive Plan	5,700,000	4,109,295	0 – 5 Years	5 – 10 Years
1999 Plan.....................................	10,500,000	7,948,407	3 – 4 Years	7 – 10 Years
Non-Employee Directors Plan......	500,000	33,350	0 – 6 Months	10 Years

A summary of the status of our stock option plans at December 31, 2006, 2005 and 2004, and changes during the years then ended is presented in the table and narrative below:

	2006		2005		2004	
	Shares	Wtd. Avg. Exercise Price	Shares	Wtd. Avg. Exercise Price	Shares	Wtd. Avg. Exercise Price
Outstanding at Beginning of Year................................	3,421,849	$45.21	5,026,436	$44.18	6,499,507	$35.45
Granted	-	$ -	-	$ -	354,525	$60.91
Exercised...............................	(618,746)	$44.82	(1,505,399)	$41.48	(1,712,685)	$34.16
Forfeited................................	(198,886)	$41.95	(99,188)	$50.48	(114,911)	$49.11
Outstanding at End of Year....	2,604,217	$46.02	3,421,849	$45.21	5,026,436	$44.18
Exercisable at End of Year.....	2,310,392	$44.49	2,260,059	$41.01	3,154,197	$39.47
Weighted-Average Fair Value of Options Granted............		$ -		$ -		$16.87
Aggregate Intrinsic Value of Options Exercisable at End of Period............................		$147.9				
Intrinsic Value of Options Exercised During the Period (In millions)...........		$ 34.1				
Cash Received from Exercise of Options During the Period (In millions)...........		$ 27.7				

The following table sets forth our common stock options outstanding at December 31, 2006, weighted-average exercise prices, weighted-average remaining contractual lives, common stock options exercisable and the exercisable weighted-average exercise price:

	Options Outstanding			Options Exercisable	
Price Range	Number Outstanding	Wtd. Avg. Exercise Price	Wtd. Avg. Remaining Contractual Life	Number Exercisable	Wtd. Avg. Exercise Price
$00.00 - $23.81	390,671	$ 23.81	2.76 years	390,671	$ 23.81
$24.75 - $43.10	552,366	$ 36.28	4.50 years	507,441	$ 35.67
$49.00 - $53.20	628,408	$ 50.81	4.15 years	628,408	$ 50.81
$53.60 - $60.18	723,872	$ 54.93	4.13 years	723,872	$ 54.93
$60.79 - $61.40	308,900	$ 60.91	5.04 years	60,000	$ 61.40
	2,604,217	$ 46.02	4.12 years	2,310,392	$ 44.49

Under the employee stock purchase plan, we may sell up to 2,400,000 shares of common stock to eligible employees. Employees purchase shares through voluntary payroll deductions. Through 2004, shares were purchased quarterly at a 15% discount from the closing price of the common stock on the last trading day of each calendar quarter. Beginning with the

March 31, 2005 quarterly purchase, the discount was reduced to 5%, thus making the employee stock purchase plan a non-compensatory plan under SFAS No. 123R. Employees purchased 36,772 shares, 45,541 shares and 86,255 shares for plan years 2006, 2005 and 2004, respectively. Using the Black-Scholes model to assign value to the option inherent in the right to purchase stock under the provisions of the employee stock purc hase plan, the weighted-average fair value per share of purchase rights granted in 2004 was $11.28. We implemented a Foreign Subsidiary Employees Stock Purchase Plan for our employees working in Canada. This plan mirrors the Employee Stock Purchase Plan for our United States employees. Employees were eligible to participate in the program beginning April 1, 2006. Employees purchased 2,098 shares during 2006.

Kinder Morgan Energy Partners

Kinder Morgan Energy Partners has three common unit-based compensation plans: A common unit option plan, the Directors' Unit Appreciation Rights Plan and the Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan.

The common unit option plan was established in 1998. The plan was authorized to grant up to 500,000 options to key personnel and terminates in March, 2008. The options granted generally have a term of seven years, vest 40% on the first anniversary of the date of grant and 20% on each of the next three anniversaries, and have exercise prices equal to the market price of the common units at the grant date. No grants have been made under this plan since May 2000. During 2006, 4,200 options to purchase common units were cancelled or forfeited, and 21,100 options to purchase common units were exercised at an average price of $19.67 per unit. The common units underlying these options had an average fair market value of $46.43 per unit. As of December 31, 2006, there were no outstanding options under this plan.

The Directors' Unit Appreciation Rights Plan was established on April 1, 2003. Pursuant to this plan, each of Kinder Morgan Management's three non-employee directors was eligible to receive common unit appreciation rights. Upon the exercise of unit appreciation rights, Kinder Morgan Energy Partners will pay, within thirty days of the exercise date, the participant an amount of cash equal to the excess, if any, of the aggregate fair market value of the unit appreciation rights exercised as of the exercise date over the aggregate award price of the rights exercised. The fair market value of one unit appreciation right as of the exercise date will be equal to the closing price of one common unit on the New York Stock Exchange on that date. The award price of one unit appreciation right will be equal to the closing price of one common unit on the New York Stock Exchange on the date of grant. All unit appreciation rights granted vest on the six-month anniversary of the date of grant and have a ten year expiration. A total of 52,500 unit appreciation rights were granted in 2003 and 2004, and as of December 31, 2006, all of these unit appreciation rights were fully vested and remained outstanding. In 2005, this plan was replaced with the Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan for Non-Employee Directors, discussed following.

The Kinder Morgan Energy Partners, L.P. Common Unit Compensation Plan recognizes that the compensation to be paid to each non-employee director is fixed by the Kinder Morgan Management board, generally annually, and that the compensation is expected to include an annual retainer payable in cash. Pursuant to the plan, in lieu of receiving cash compensation, each non-employee director may elect to receive common units. A non-employee director may make a new election each calendar year. The total number of common units authorized under this compensation plan is 100,000. All common units issued under this plan are subject to forfeiture restrictions that expire six months from the date of issuance. A total of 10,500 common units were issued to non-employee directors in 2005 and 2006 as a result of their elections to receive common units in lieu of cash compensation.

15. Commitments and Contingent Liabilities

(A) Operating Leases and Purchase Obligations

Expenses incurred under operating leases were $111.6 million in 2006, $25.1 million in 2005 and $24.3 million in 2004. The principal reasons for the increased expense in 2006 compared to 2005 and 2004 is due to our implementation of EITF No. 04-5, which requires us to include Kinder Morgan Energy Partners and its consolidated subsidiaries as consolidated subsidiaries in our consolidated financial statements effective January 1, 2006 and the inclusion of Terasen's operating leases. We acquired Terasen effective November 30, 2005. See Note 4 for information regarding this acquisition. Future minimum commitments under major operating leases and gas purchase contracts as of December 31, 2006 are as follows:

Year	Operating Leases[1]	Purchase Obligations[2]	Total
		(In millions)	
2007	$ 98.4	$ 450.8	$ 549.2
2008	76.5	31.0	107.5
2009	65.3	34.0	99.3
2010	60.9	8.9	69.8
2011	57.0	-	57.0
Thereafter	565.1	-	565.1
Total	$ 923.2	$ 524.7	$ 1,447.9

[1] Approximately $0.4 million, $0.3 million and $0.2 million in 2007, 2008 and 2009, respectively, is attributable to operating lease obligations associated with our discontinued U.S.-based natural gas distribution operations.

[2] Approximately $12.1 million, $11.4 million, $10.2 million and 8.9 million in 2007, 2008, 2009 and 2010, respectively, is attributable to purchase obligations associated with our discontinued U.S.-based natural gas distribution operations.

We have not reduced our total minimum payments for future minimum sublease rentals, aggregating approximately $20.4 million. The remaining terms on our operating leases range from one to 62 years.

Terasen Gas and TGVI have entered into gas purchase contracts, which represent future purchase obligations. Gas purchase contract commitments are based on market prices that vary with gas commodity indices. The amounts shown in the preceding table reflect index prices that were in effect at December 31, 2006. Our discontinued U.S.-based natural gas distribution business is obligated under certain gas purchase contracts, dating from 1973, to purchase natural gas at fixed and escalating prices from a certain field in Montana. See Note 1(O).

(B) Capital Leases

Future minimum commitments under capital leases as of December 31, 2006 as follows (In millions):

Year	Commitment
2007	$ 1.5
2008	1.4
2009	1.4
2010	1.4
2011	1.3
Thereafter	1.0
Subtotal	8.0
Less: Amount representing interest	(0.7)
Present value of minimum capital lease payments	$ 7.3

Amortization of assets recorded under capital leases is included with depreciation expense. The components of property, plant and equipment, net recorded under capital leases are as follows (in millions):

	December 31, 2006
Property, Plant and Equipment	$ 22.6
Less: Accumulated Amortization	(15.3)
	$ 7.3

(C) Guarantee

As a result of our December 1999 sale of assets to ONEOK, ONEOK became primarily obligated for the lease of the Bushton gas processing facility. We remain secondarily liable for the lease, which had a remaining minimum obligation of approximately $127.2 million at December 31, 2006, with payments that average approximately $23 million per year through 2012.

(D) Capital Expenditures Budget

Approximately $796.4 million of our consolidated capital expenditure budget for 2007 had been committed for the purchase of plant and equipment at December 31, 2006.

(E) Commitments for Incremental Investment

We could be obligated (i) based on operational performance of the equipment at the Jackson, Michigan power generation facility to invest up to an additional $3 to $8 million per year for the next 12 years and (ii) based on cash flows generated by the facility, to invest up to an additional $25 million beginning in 2018, in each case in the form of an incremental preferred interest.

(F) Government Grant

In prior years, TGVI received non-interest bearing, repayable loans from the Canadian Federal and Provincial governments of C$50 million and C$25 million respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as a government grant and have reduced the amounts reported for property, plant and equipment. The government loans are repayable in any fiscal year after 2002 and prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. On an annual basis, if the criteria has been met and non-governmental financing is available, plant and equipment and long-term debt is increased in accordance with the approved capital structure, as will the rate base used in determining rates. In 2006, all the criteria was met and TGVI obtained additional financing through a new credit agreement (see Note 10) to make a repayment on the governmental loans of $5.6 million (C$6.2 million). Additionally, since all the criteria have been met and TGVI currently has non-governmental financing available, TGVI is expected to make an annual repayment on the governmental loans in 2007 of approximately $3.1 million (C$3.7 million). Accordingly, this amount is reported within the caption "Current Maturities of Long-term Debt" in the accompanying Consolidated Balance Sheet at December 31, 2006. The balance payable on these governmental loans at December 31, 2006, excluding the current portion, was $55.9 million (C$65.1 million), which amount is reported in the caption "Property, Plant and Equipment, Net" in the accompanying Consolidated Balance Sheet. The amounts are not included in the obligations in the table above as the amounts and timing of repayments is dependent upon the approved Revenue Deficiency Deferral Account recovery each year and the ability to replace the loans with non-government subordinated debt financing on reasonable commercial terms.

(G) Contingent Debt

Cortez Pipeline Company Debt

Pursuant to a certain Throughput and Deficiency Agreement, the partners of Cortez Pipeline Company (Kinder Morgan CO_2 Company, L.P. – 50% partner; a subsidiary of Exxon Mobil Corporation – 37% partner; and Cortez Vickers Pipeline Company – 13% partner) are required, on a several, percentage ownership basis, to contribute capital to Cortez Pipeline Company in the event of a cash deficiency. The Throughput and Deficiency Agreement contractually supports the borrowings of Cortez Capital Corporation, a wholly-owned subsidiary of Cortez Pipeline Company, by obligating the partners of Cortez Pipeline Company to fund cash deficiencies at Cortez Pipeline Company, including cash deficiencies relating to the repayment of principal and interest on borrowings by Cortez Capital Corporation. Parent companies of the respective Cortez Pipeline Company partners further severally guarantee, on a percentage basis, the obligations of the Cortez Pipeline Company partners under the Throughput and Deficiency Agreement.

As of December 31, 2006, the debt facilities of Cortez Capital Corporation consisted of:

- $75 million of Series D notes due May 15, 2013;
- a $125 million short-term commercial paper program; and
- a $125 million five-year committed revolving credit facility due December 22, 2009 (to support the above-mentioned $125 million commercial paper program).

As of December 31, 2006, Cortez Capital Corporation had $73.9 million of commercial paper outstanding with an average interest rate of 5.3846%, the average interest rate on the Series D notes was 7.14%, and there were no borrowings under the credit facility.

Due to Kinder Morgan Energy Partners' indirect ownership of Cortez Pipeline Company through Kinder Morgan CO_2 Company, L.P., Kinder Morgan Energy Partners severally guarantees 50% of the debt of Cortez Capital Corporation. Shell Oil Company shares our several guaranty obligations jointly and severally; however, Kinder Morgan Energy Partners is obligated to indemnify Shell for liabilities it incurs in connection with such guaranty. With respect to Cortez's long-term revolving credit facility, Shell was released of its guaranty obligations on December 31, 2006; with respect to Cortez's Series D notes, in December 2006, Kinder Morgan Energy Partners entered into a letter of credit issued by JP Morgan Chase in the amount of $37.5 million to secure its indemnification obligations to Shell for 50% of the $75 million in principal amount of Series D notes outstanding as of December 31, 2006; and with respect to Cortez's short-term commercial paper borrowings, in January 2007, Kinder Morgan Energy Partners entered into an additional letter of credit issued by JP Morgan Chase in the amount of $37.5 million to secure its indemnification obligations to Shell for 50% of the outstanding commercial paper borrowings as of December 31, 2006.

Red Cedar Gathering Company Debt

In October 1998, Red Cedar Gathering Company sold $55 million in aggregate principal amount of Senior Notes due October 31, 2010. The $55 million was sold in 10 different notes in varying amounts with identical terms.

The Senior Notes are collateralized by a first priority lien on the ownership interests, including Kinder Morgan Energy Partners' 49% ownership interest, in Red Cedar Gathering Company. The Senior Notes are also guaranteed by Kinder Morgan Energy Partners and the other owner of Red Cedar Gathering Company jointly and severally. The principal is to be repaid in seven equal installments beginning on October 31, 2004 and ending on October 31, 2010. As of December 31, 2006, $31.4 million in principal amount of notes were outstanding

In the first quarter of 2007, Red Cedar plans to refinance the outstanding balance of its existing Senior Notes through a private placement of $100 million in principal amount of ten year fixed rate notes. Bids for the new notes were due February 15, 2007, and the placement is expected to close on March 15, 2007.

Nassau County, Florida Ocean Highway and Port Authority Debt

Nassau County, Florida Ocean Highway and Port Authority is a political subdivision of the State of Florida. During 1990, Ocean Highway and Port Authority issued its Adjustable Demand Revenue Bonds in the aggregate principal amount of $38.5 million for the purpose of constructing certain port improvements located in Fernandino Beach, Nassau County, Florida. The bond indenture is for 30 years and allows the bonds to remain outstanding until December 1, 2020. A letter of credit was issued as security for the Adjustable Demand Revenue Bonds and was guaranteed by the parent company of Nassau Terminals LLC, the operator of the port facilities. In July 2002, Kinder Morgan Energy Partners acquired Nassau Terminals LLC and became guarantor under the letter of credit agreement. In December 2002, Kinder Morgan Energy Partners issued a $28 million letter of credit under its credit facilities and the former letter of credit guarantee was terminated. Principal payments on the bonds are made on the first of December each year and corresponding reductions are made to the letter of credit. As of December 31, 2006, this letter of credit had an outstanding balance under our credit facility of $23.9 million.

Rockies Express Pipeline LLC Debt

On April 28, 2006, Rockies Express Pipeline LLC entered into a $2.0 billion five-year, unsecured revolving credit facility due April 28, 2011. This credit facility supports a $2.0 billion commercial paper program that was established in May 2006, and borrowings under the commercial paper program reduce the borrowings allowed under the credit facility; this facility can be amended to allow for borrowings up to $2.5 billion. Borrowings under the Rockies Express credit facility and commercial paper program will be primarily used to finance the construction of the Rockies Express interstate natural gas pipeline and to pay related expenses, and the borrowings will not reduce the borrowings allowed under Kinder Morgan Energy Partners' credit facility described in Note 10.

In addition, pursuant to certain guaranty agreements, all three member owners of West2East Pipeline LLC (and its subsidiary Rockies Express Pipeline, LLC) have agreed to guarantee borrowings under the Rockies Express credit facility and under the Rockies Express commercial paper program severally in the same proportion as their percentage ownership of the member interests in Rockies Express Pipeline LLC. The three member owners and their respective ownership interests consist of the following: Kinder Morgan Energy Partners' subsidiary Kinder Morgan W2E Pipeline LLC – 51%, Sempra Energy – 25%, and ConocoPhillips – 24%. As of December 31, 2006, Rockies Express Pipeline LLC had $790.1 million of commercial paper outstanding, and there were no borrowings under its five-year credit facility. Accordingly, as of December 31, 2006, Kinder Morgan Energy Partners' contingent share of Rockies Express' debt was $403.0 million (51% of total commercial paper borrowings).

(H) Standby Letters of Credit

Letters of credit totaling $616.9 million outstanding at December 31, 2006 consisted of the following: (i) four letters of credit, totaling $272 million, supporting our hedging of commodity risk, (ii) two letters of credit, totaling $52.8 million securing accrued unfunded retirement obligations to certain current and retired executives and employees of Terasen, (iii) a combined $39.7 million in two letters of credit supporting the construction of Kinder Morgan Energy Partners' Kinder Morgan Louisiana Pipeline, (iv) a $37.5 million letter of credit supporting Kinder Morgan Energy Partners' indemnification obligations on the Series D note borrowings of Cortez Capital Corporation, (v) Kinder Morgan Energy Partners' $30.3 million guarantee under letters of credit supporting its International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds, (vi) three letters of credit, totaling $29.0 million to secure obligations for construction of new pump stations on the Trans Mountain system, (vii) a $25.4 million letter of credit supporting Kinder Morgan Energy Partners' Kinder Morgan Liquids Terminals LLC New Jersey Economic Development Revenue Bonds, (viii) a $24.1 million letter of credit supporting Kinder Morgan Energy Partners' Kinder Morgan Operating L.P. "B" tax-exempt bonds, (ix) a $23.9 million letter of credit supporting Nassau County, Florida Ocean Highway and Port Authority tax-exempt bonds, (x) four letters of credit, totaling $21.4 million, required under provisions of our property and casualty, worker's compensation and general liability insurance policies, (xi) a $15.3 million letter of credit to fund the Debt Service Reserve Account required under the Express System's trust indenture, (xii) a $10.6 million letter of credit supporting the subordination of operating fees payable to us for operation of the Jackson, Michigan power generation facility to payments due under the operating lease of the facilities and (xiii) 41 letters of credit, totaling $34.9 million supporting various company functions.

(I) Other Obligations

Other obligations are discussed in Note 7.

16. Fair Value

The following fair values of Long-term Debt and Capital Securities were estimated based on an evaluation made by an independent securities analyst. See Note 10 for additional information regarding the Long-term Debt of Kinder Morgan, Inc. and its consolidated subsidiaries. Fair values of "Energy Financial Instruments, Net" reflect the estimated amounts that we would receive or pay to terminate the contracts at the reporting date, thereby taking into account the current unrealized gains or losses on open contracts. See Note 12 for additional information regarding Energy Financial Instruments and Interest Rate Swaps of Kinder Morgan, Inc. and its consolidated subsidiaries. Market quotes are available for substantially all instruments we use.

	December 31,			
	2006[1]		2005	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Total Long-term Debt	$11,589.0 [2]	$11,622.8 [2]	$ 7,085.4 [2]	$ 7,492.2 [2]
Total Energy Financial Instruments, Net	$ (928.7) [3]	$ (928.7) [3]	$ 72.8	$ 72.8
Total Outstanding Interest Rate Swaps	$ 20.9	$ 20.9	$ (39.3)	$ (39.3)

[1] Due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts and balances of Kinder Morgan Energy Partners and its consolidated subsidiaries are included in our consolidated financial statements.

[2] Includes an adjustment exactly offsetting the fair value of the outstanding interest rate swaps. See Note 12.

[3] Includes ($9.0) million associated with assets classified as held for sale. See Note 7 for discussions on our discontinued operations.

17. Business Segment Information

Due to our implementation of EITF No. 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights* (see Note 1(B)), we include Kinder Morgan Energy Partners and its consolidated subsidiaries as consolidated subsidiaries in our consolidated financial statements, and we include the business segments of Kinder Morgan Energy Partners in our business segment information, effective January 1, 2006.

On November 30, 2005, we completed the acquisition of Terasen (see Note 4) and, accordingly, Terasen's results of operations, including its two main business segments, Terasen Gas and Kinder Morgan Canada (formerly Terasen Pipelines), are included in our consolidated results of operations beginning on that date. In February 2007, we entered into a definitive agreement to sell Terasen Gas (see Notes 6 and 21).

In accordance with the manner in which we manage our businesses, including the allocation of capital and evaluation of business segment performance, we report our operations in the following segments: (1) Natural Gas Pipeline Company of America and certain affiliates, referred to as Natural Gas Pipeline Company of America or NGPL, a major interstate natural gas pipeline and storage system; (2) Terasen Gas, the regulated sale and transportation of natural gas to residential, commercial and industrial customers in British Columbia, Canada; (3) Kinder Morgan Canada, principally consisting of the ownership and operation of three refined products and crude oil pipelines, (a) Trans Mountain Pipeline, (b) Corridor Pipeline and (c) a one-third interest in the Express and Platte pipeline systems; (4) Power, the ownership and operation of natural gas-fired electric generation facilities; (5) Prior to its sale as discussed following, TransColorado Gas Transmission Company, referred to as TransColorado, an interstate natural gas pipeline located in western Colorado and northwest New Mexico; (6) Products Pipelines – KMP, the ownership and operation of refined petroleum products pipelines that deliver gasoline, diesel fuel, jet fuel and natural gas liquids to various markets plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities; (7) Natural Gas Pipelines – KMP, the ownership and operation of major interstate and intrastate natural gas pipeline and storage systems; (8) CO_2 – KMP, the production, transportation and marketing of carbon dioxide ("CO_2") to oil fields that use CO_2 to increase production of oil plus ownership interests in and/or operation of oil fields in West Texas plus the ownership and operation of a crude oil pipeline system in West Texas and (9) Terminals – KMP, the ownership and/or operation of liquids and bulk terminal facilities and rail transloading and materials handling facilities located throughout the United States. Our investment in TransColorado Gas Transmission Company was contributed to Kinder Morgan Energy Partners effective November 1, 2004 (see Note 5) and, beginning January 2006, the activities and assets related to that segment are reported in the Natural Gas Pipelines – KMP segment. In August 2006, we reached an agreement to sell our Kinder Morgan Retail segment. Accordingly, the activities and assets related to that segment are presented as discontinued items in our consolidated financial statements. In previous periods, we owned and operated other lines of business that we discontinued during 1999 and, in 2005, we discontinued the water and utility services businesses acquired with Terasen. See Note 7 for additional information regarding discontinued operations.

The accounting policies we apply in the generation of business segment earnings are generally the same as those applied to our consolidated operations and described in Note 1, except that (i) certain items below the "Operating Income" line (such as interest expense) are either not allocated to business segments or are not considered by management in its evaluation of business segment performance, (ii) equity in earnings of equity method investees (other than Kinder Morgan Energy Partners, the accounts, balances and results of operations of which are now consolidated with our own) are included in segment earnings (these equity method earnings are included in "Other Income and (Expenses)" in the accompanying Consolidated Statements of Operations), (iii) certain items included in operating income (such as general and administrative expenses) are not considered by management in its evaluation of business segment performance, (iv) gains and losses from incidental sales of assets are included in segment earnings and (v) our business segments that are also segments of Kinder Morgan Energy Partners include certain other income and expenses and income taxes in their segment earnings. With adjustment for these items, we currently evaluate business segment performance primarily based on segment earnings in relation to the level of capital employed. In addition, because Kinder Morgan Energy Partners' partnership agreement requires it to distribute 100% of its available cash to its partners on a quarterly basis (Kinder Morgan Energy Partners' available cash consists primarily of all of its cash receipts, less cash disbursements and changes in reserves), we consider each period's earnings before all non-cash depreciation, depletion and amortization expenses to be an important measure of business segment performance for our segments that are also segments of Kinder Morgan Energy Partners. We account for intersegment sales at market prices, while we account for asset transfers at either market value or, in some instances, book value.

NGPL's principal delivery market area encompasses the states of Illinois, Indiana and Iowa and secondary markets in portions of Wisconsin, Nebraska, Kansas, Missouri and Arkansas. NGPL is the largest transporter of natural gas to the Chicago, Illinois area, its largest market. During 2006, approximately 39% of NGPL's transportation represented deliveries to this market. NGPL's storage capacity is largely located near its transportation delivery markets, effectively serving the same customer base. NGPL has a number of individually significant customers, including local gas distribution companies in the greater Chicago area and major natural gas marketers and, during 2006, approximately 50% of its operating revenues from tariff services were attributable to its eight largest customers.

Terasen Gas provides natural gas service to more than 100 communities with a service territory that has an estimated population of approximately 4.3 million. Terasen Gas is one of the largest natural gas distribution companies in Canada. As of December 31, 2006, Terasen Gas transported and distributed natural gas to approximately 905,000 residential, commercial and industrial customers in British Columbia. Terasen Gas' service area extends from Vancouver to the Fraser Valley and the interior of British Columbia. The transmission and distribution business is carried on under statutes and franchises or operating agreements granting the right to operate in the municipalities or areas served. Terasen Gas is regulated by the British Columbia Utilities Commission ("BCUC").

Kinder Morgan Canada operates the Trans Mountain Pipe Line, a common carrier pipeline system originating at Edmonton, Alberta for the transportation of crude petroleum, refined petroleum and iso-octane to destinations in the interior and on the west coast of British Columbia, with connecting pipelines that deliver petroleum to refineries in the State of Washington and that transport jet fuel from Vancouver area refineries and marketing terminals and Westridge Marine Terminal to Vancouver International Airport. Kinder Morgan Canada also operates the Corridor Pipeline, which transports diluted bitumen produced at the Muskeg River Mine located approximately 43 miles north of Fort McMurray, Alberta to a heavy oil upgrader near Edmonton, Alberta, a distance of approximately 281 miles. A smaller diameter parallel pipeline transports recovered diluent from the upgrader back to the mine. Corridor also consists of two additional pipelines, each 27 miles in length, to provide pipeline transportation between the Scotford Upgrader and the existing trunk pipeline facilities of Trans Mountain and Enbridge Pipelines Inc. in the Edmonton area. Both Trans Mountain Pipe Line and Corridor Pipeline are owned by Terasen. Kinder Morgan Canada also operates, and Terasen owns a one-third interest in, the Express System. The Express System is a batch-mode, common-carrier, crude pipeline system comprised of the Express Pipeline and the Platte Pipeline. The Express System transports a wide variety of crude types produced in Alberta to markets in the Rocky Mountain and Midwest regions of the United States.

Power's current principal market is represented by the local electric utilities in Colorado, which purchase the power output from its generation facilities. Due to the adoption of FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*, the results of operations of our Triton Power affiliates are included in our consolidated operating results and in the results of our Power segment beginning with the first quarter of 2004. Although the results of Triton have an impact on the total operating revenues and expenses of the Power business segment, after taking into account the associated minority interests, the consolidation of Triton had no effect on Power's segment earnings. During 2006, approximately 64% of Power's operating revenues were for operating the Jackson, Michigan Power facility, 24% were electric sales revenues from XCEL Energy's Public Service Company of Colorado under a long-term contract, and the remaining 12% were primarily for operating the Ft. Lupton, Colorado power facility and a gas-fired power facility in Snyder, Texas that began operations during the second quarter of 2005 and provides electricity to Kinder Morgan Energy Partners' SACROC operations.

Products Pipelines – KMP consists of approximately 10,000 miles of refined petroleum products pipelines that deliver gasoline, diesel fuel, jet fuel and natural gas liquids to various markets; plus over 60 associated product terminals and petroleum pipeline transmix processing facilities serving customers across the United States.

Natural Gas Pipelines – KMP consists of approximately 14,000 miles of interstate and intrastate natural gas transmission pipelines and gathering lines, plus natural gas storage, treating and processing facilities, through which natural gas is gathered, transported, stored, treated, processed and sold.

CO_2 – KMP produces, transports through pipelines and markets CO_2 to oil fields that use CO_2 to increase production of oil; owns interests in and/or operates ten oil fields in West Texas and owns and operates a crude oil pipeline system in West Texas.

Terminals – KMP consists of approximately 95 owned or operated liquids and bulk terminal facilities and more than 60 rail transloading and materials handling facilities located throughout the United States, that together transload, store and deliver a wide variety of bulk, petroleum, petrochemical and other liquids products for customers across the United States.

Our business activities expose us to credit risk with respect to collection of accounts receivable. In order to mitigate that risk, we routinely monitor the credit status of our existing and potential customers. When customers' credit ratings do not meet our requirements for the extension of unsupported credit, we obtain cash prepayments or letters of credit. Note 1(G) provides information on the amount of prepayments we have received.

During 2006, 2005 and 2004, we did not have revenues from any single customer that exceeded 10% of our consolidated operating revenues.

Financial information by segment follows (in millions):

	2006	2005	2004
Segment Earnings:[1]			
NGPL	$ 499.0	$ 435.2	$ 392.8
Terasen Gas	312.9	45.2	–
Kinder Morgan Canada	119.9	12.5	–
Power	21.1	19.7	15.3
TransColorado[2]	–	–	20.3
Products Pipelines – KMP	404.9	–	–
Natural Gas Pipelines – KMP	509.1	–	–
CO_2 – KMP	295.2	–	–
Terminals – KMP	333.6	–	–
Total Segment Earnings	2,495.7	512.6	428.4
Earnings from Investment in Kinder Morgan Energy Partners[3]	–	605.4	558.1
Interest and Corporate Expenses, Net[4, 5, 6, 7]	(2,191.9)	(242.6)	(280.3)
Income from Continuing Operations Before Income Taxes[1]	$ 303.8	$ 875.4	$ 706.2

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	2006	2005	2004
Revenues from External Customers			
NGPL	$ 1,114.4	$ 947.3	$ 778.9
Terasen Gas	1,523.9	223.3	–
Kinder Morgan Canada	212.8	18.9	–
Power	60.0	54.2	70.0
TransColorado[2]	–	–	28.8
Products Pipelines – KMP	776.3	–	–
Natural Gas Pipelines – KMP	6,558.4	–	–
CO2 – KMP	736.5	–	–
Terminals – KMP	864.1	–	–
Total Segment Revenues	11,846.4	1,243.7	877.7
Other Revenues[8]	–	10.8	–
Total Revenues	$11,846.4	$ 1,254.5	$ 877.7

	2006	2005	2004
Intersegment Revenues			
NGPL	$ 3.6	$ –	$ –
Terasen Gas	–	–	–
Kinder Morgan Canada	0.9	–	–
Power	–	–	–
TransColorado[2]	–	–	–
Products Pipelines – KMP	–	–	–
Natural Gas Pipelines – KMP	19.3	–	–
CO2 – KMP	–	–	–
Terminals – KMP	0.7	–	–
Total Intersegment Revenues	$ 24.5	$ –	$ –

	2006	2005	2004
Depreciation, Depletion and Amortization			
NGPL	$ 104.5	$ 99.6	$ 94.5
Terasen Gas	90.3	7.5	–
Kinder Morgan Canada	35.8	3.0	–
Power	2.1	3.3	3.5
TransColorado[2]	–		3.6
Products Pipelines – KMP	82.9	–	–
Natural Gas Pipelines – KMP	65.4	–	–
CO2 – KMP	190.9	–	–
Terminals – KMP	74.5	–	–
Total Consolidated Depreciation, Depletion and Amortization	$ 646.4	$ 113.4	$ 101.6

	2006	2005	2004
Capital Expenditures			
NGPL	$ 193.4	$ 129.7	$ 88.2
Terasen Gas	126.9	9.5	–
Kinder Morgan Canada	204.6	5.3	–
Power	–	–	–
TransColorado[2]	–	–	15.0
Products Pipelines – KMP	195.9	–	–
Natural Gas Pipelines – KMP	271.6	–	–
CO2 – KMP	283.0	–	–
Terminals – KMP	307.7	–	–
Total Consolidated Capital Expenditures	$ 1,583.1	$ 144.5	$ 103.2

	2006	2005	2004
Assets at December 31[9]			
NGPL	$ 5,728.9	$ 5,597.8	$ 5,546.5
Terasen Gas	4,145.4	3,670.2	-
Kinder Morgan Canada	2,544.5	1,681.9	-
Power	387.4	372.5	378.0
TransColorado[2]	-	-	-
Products Pipelines – KMP	4,812.9	-	-
Natural Gas Pipelines – KMP	3,796.6	-	-
CO2 – KMP	1,875.6	-	-
Terminals – KMP	2,564.1	-	-
Total segment assets	25,855.4	11,322.4	5,924.5
Investment in Kinder Morgan Energy Partners	-	2,202.9	2,305.2
Goodwill[9]	-	2,781.0	918.1
Other[10]	940.2	1,145.3	969.1
Total Consolidated Assets	$26,795.6	$17,451.6	$10,116.9

[1] Includes $19.0 million of income tax expense that was allocated to business segments that are also business segments of Kinder Morgan Energy Partners.

[2] Effective November 1, 2004 we contributed our investment in TransColorado Gas Transmission Company to Kinder Morgan Energy Partners (see Note 5). TransColorado was a 50/50 joint venture with Questar Corp. until we bought Questar's interest effective October 1, 2002, thus becoming the sole owner. As a result, TransColorado's results shown above reflect 100% of its results on a consolidated basis from January 1, 2004 through October 31, 2004. With the inclusion of Kinder Morgan Energy Partners in our consolidated financial statements, beginning January 1, 2006 TransColorado's results are included as part of the Natural Gas Pipelines – KMP business segment.

[3] Equity in Earnings of Kinder Morgan Energy Partners for 2005 includes a reduction in pre-tax earnings of approximately $63.3 million ($40.3 million after tax) resulting principally from the effects of certain regulatory, environmental, litigation and inventory items on Kinder Morgan Energy Partners' earnings.

[4] Includes (i) general and administrative expenses, (ii) interest expense, (iii) minority interests and (iv) other, net.

[5] Results for 2006 include (i) a reduction in pre-tax income of $650.5 million resulting from the goodwill impairment charge associated with Terasen Gas (see Note 6), (ii) a reduction in pre-tax income of $22.3 million ($14.1 million after tax) resulting from non-cash charges to mark to market certain interest rate swaps and (ii) miscellaneous other items totaling a net decrease of $0.8 million in pre-tax income ($0.5 million after tax).

[6] Results for 2005 include (i) pre-tax gains of $73.9 million ($31.6 million after tax) from the sale of Kinder Morgan Management shares during the second and fourth quarters of 2005, (ii) a pre-tax charge of $15.0 million ($9.5 million after tax) for our contribution to the Kinder Morgan Foundation, (iii) a pre-tax charge of $6.5 million ($4.1 million after tax) for the impairment of certain investments in our Power business segment, (iv) net pre-tax gains on currency transactions and swaps of $2.3 million ($1.4 million after tax) and (v) a decrease in after-tax minority interest expense in Kinder Morgan Management of $19.6 million, due principally to the items discussed in Note 3 above.

[7] Results for 2004 include (i) a pre-tax charge of $15.0 million ($9.4 million after tax), net of the recognition of deferred power development revenues and the impact of the resolution of certain litigation contingencies, for the impairment of certain investments in our Power business segment, (ii) a pre-tax charge of $3.9 million ($2.4 million after tax) due to the early extinguishment of debt and (iii) miscellaneous other items totaling a net decrease of $1.6 million in pre-tax income ($1.0 million after tax).

[8] Represents revenues from KM Insurance Ltd., our wholly owned subsidiary that was formed during the second quarter of 2005 for the purpose of providing insurance services to Kinder Morgan, Inc. and Kinder Morgan Energy Partners. KM Insurance Ltd. was formed as a Class 2 Bermuda insurance company, the sole business of which is to issue policies for Kinder Morgan, Inc. and Kinder Morgan Energy Partners to secure the deductible portion of our workers' compensation, automobile liability and general liability policies placed in the commercial insurance market. Due to our adoption of EITF 04-5 (see Note 1(B)), effective January 1, 2006 the results of operations of Kinder Morgan Energy Partners are included in our consolidated results of operations and, consequently, all 2006 revenues of KM Insurance Ltd. have been eliminated in consolidation.

[9] For 2006, segment assets include goodwill allocated to the segments.

[10] Includes assets of discontinued operations, cash, restricted deposits, market value of derivative instruments (including interest rate swaps) and miscellaneous corporate assets (such as information technology and telecommunications equipment) not allocated to individual segments.

Geographic Information

Prior to 2005, all but an insignificant amount of our assets and operations were located in the continental United States. Upon our acquisition of Terasen on November 30, 2005, we obtained significant assets and operations in Canada. Following is geographic information regarding the revenues and long-lived assets of our business segments. Revenues from Kinder Morgan Canada and Terasen Gas, as presented below, include only the revenues subsequent to our November 30, 2005 acquisition of Terasen. Revenues from Products Pipeline – KMP, Natural Gas Pipelines – KMP, CO_2 – KMP and Terminals – KMP include only the revenues subsequent to our adoption of EITF 04-5, effective January 1, 2006 (see Note 1(B)).

Revenues from External Customers

	Year Ended December 31, 2006			
	United States	Canada	Mexico and Other[1]	Total
	(In millions)			
NGPL	$ 1,114.4	$ –	$ –	$ 1,114.4
Terasen Gas	–	1,523.9	–	1,523.9
Kinder Morgan Canada	11.2	201.6	–	212.8
Power	60.0	–	–	60.0
Products Pipelines – KMP	764.6	11.7	–	776.3
Natural Gas Pipelines – KMP	6,544.3	–	14.1	6,558.4
CO_2 – KMP	736.5	–	–	736.5
Terminals – KMP	858.7	–	5.4	864.1
	$ 10,089.7	$ 1,737.2	$ 19.5	$ 11,846.4

	Year Ended December 31, 2005			
	United States	Canada	Mexico and Other[1]	Total
	(In millions)			
NGPL	$ 947.3	$ –	$ –	$ 947.3
Terasen Gas	–	223.3	–	223.3
Kinder Morgan Canada	0.9	18.0	–	18.9
Power	54.2	–	–	54.2
Other	–	–	10.8	10.8
	$ 1,002.4	$ 241.3	$ 10.8	$ 1,254.5

Long-lived Assets[2]

	At December 31, 2006			
	United States	Canada	Mexico and Other[1]	Total
	(In thousands)			
NGPL	$ 5,558.2	$ –	$ –	$ 5,558.2
Terasen Gas	–	2,898.7	–	2,898.7
Kinder Morgan Canada	326.1	1,552.5	–	1,878.6
Power	346.4	–	–	346.4
Products Pipelines – KMP	3,712.1	47.3	–	3,759.4
Natural Gas Pipelines – KMP	2,712.7	–	84.3	2,797.0
CO_2 – KMP	1,653.1	–	–	1,653.1
Terminals – KMP	1,820.5	33.2	8.3	1,862.0
Discontinued Operations	397.9	–	24.4	422.3
Other	252.7	74.1	–	326.8
	$ 16,779.7	$ 4,605.8	$ 117.0	$ 21,502.5

	At December 31, 2005			
	United States	Canada	Mexico and Other[1]	Total
	(In thousands)			
NGPL	$ 5,470.8	$ -	$ -	$ 5,470.8
Terasen Gas	-	3,000.8	-	3,000.8
Kinder Morgan Canada	313.3	1,342.4	-	1,655.7
Power	338.3	-	-	338.3
Investment in Kinder Morgan Energy Partners	2,202.9	-	-	2,202.9
Other	619.8	35.7	24.8	680.3
	$ 8,945.1	$ 4,378.9	$ 24.8	$ 13,348.8

1 Terminals – KMP includes revenues of $5.4 million for the year ended December 31, 2006 and long-lived assets of $8.3 million at December 31, 2006 attributable to operations in the Netherlands.

2 Long-lived assets exclude goodwill and other intangibles, net.

18. Regulatory Matters

The tariffs we charge for transportation on our interstate common carrier pipelines are subject to rate regulation by the Federal Energy Regulatory Commission, referred to in this report as the FERC, under the Interstate Commerce Act. The Interstate Commerce Act requires, among other things, that interstate petroleum products pipeline rates be just and reasonable and nondiscriminatory. Pursuant to FERC Order No. 561, effective January 1, 1995, interstate petroleum products pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. FERC Order No. 561-A, affirming and clarifying Order No. 561, expanded the circumstances under which interstate petroleum products pipelines may employ cost-of-service ratemaking in lieu of the indexing methodology, effective January 1, 1995. For each of the years ended December 31, 2006, 2005 and 2004, the application of the indexing methodology did not significantly affect tariff rates on our interstate petroleum products pipelines.

On February 15, 2007, the FERC issued a notice of inquiry seeking comment on the need for changes or revisions to the FERC's reporting requirements contained in the financial forms for gas and oil pipelines and electric utilities.

On June 2, 2006, our U.S.-based retail natural gas distribution operations (which are subject to a definitive sale agreement, see Note 7) filed a general rate increase application with the Nebraska Public Service Commission seeking an additional $11.05 million of revenue per year from its Nebraska gas utility operations. A phased-in annual increase of $7.7 million went into effect subject to refund on September 1, 2006. On December 27, 2006, the Nebraska Public Service Commission issued an order approving an annual increase of $8.25 million effective January 1, 2007.

On February 28, 2006, our U.S.-based retail natural gas distribution operations filed a general rate increase application with the Wyoming Public Service Commission seeking an additional $7.94 million of revenue per year from its Wyoming gas utility operations. On September 20, 2006, the Wyoming Public Service Commission issued a Bench Decision approving an annual increase of $6.45 million effective October 1, 2006.

On February 17, 2006, Kinder Morgan Canada filed a complete National Energy Board ("NEB") application for the Anchor Loop project. On November 15, 2005, Kinder Morgan Canada filed a comprehensive environmental report with the Canadian Environmental Assessment Agency regarding the project. The C$443 million project involves looping a 98-mile section of the existing Trans Mountain pipeline system between Hinton, Alberta, and Jackman, British Columbia, and the addition of three new pump stations. With construction of the Anchor Loop, the Trans Mountain system's capacity will increase from 260,000 barrels per day ("bpd") to 300,000 bpd by the end of 2008. The public hearing of the application was held the week of August 8, 2006. On October 26, 2006, the NEB released its favorable decision on the application.

Terasen Gas Inc.'s allowed return on equity ("ROE") is determined annually based on a formula that applies a risk premium to a forecast of long-term Government of Canada bond yields. For 2005, the application of the ROE formula set Terasen Gas Inc.'s allowed ROE at 9.03%, down from 9.15% in 2004. On June 30, 2005, Terasen Gas Inc. and TGVI applied to the British Columbia Utilities Commission, referred to in this report as the BCUC, to increase their deemed equity components from 33% to 38% and from 35% to 40%, respectively. The same application also requested an increase in allowed ROEs from the levels that would have resulted from the then applicable formula, which would have been 8.29% for Terasen Gas Inc. and 8.79% for TGVI in 2006. A decision from the BCUC was rendered on the application on March 2, 2006, with an effective date as of January 1, 2006. The decision resulted in increases in the deemed equity components of Terasen Gas Inc. and TGVI to 35% and 40% in 2006, respectively, and their allowed ROEs to 8.80% and 9.5% in 2006, respectively. For 2007 the application of the new formula from the decision resulted in allowed ROEs of 8.37% and 9.07% for Terasen Gas Inc. and TGVI, respectively.

In January 2006, Kinder Morgan Canada entered into a memorandum of understanding with the Canadian Association of Petroleum Producers ("CAPP") for a new Incentive Toll Settlement (the "2006 ITS"). In September 2006, Kinder Morgan Canada completed the negotiation with CAPP on the final ITS agreement and on October 18, 2006, the CAPP Board of Governors approved the agreement. The agreement was filed with the NEB on October 19, 2006 and a favorable decision was received in November 2006. The 2006 ITS determines the tolls to be charged on the Trans Mountain system over the five-year term of the agreement, effective January 1, 2006. The agreement also governs the financial arrangements for the Pump Station Expansion and Anchor Loop projects.

We have initiated engineering, environmental, consultation and procurement activities on the proposed Corridor pipeline expansion project, as authorized and supported by shipper resolutions and the underlying firm service agreement. The proposed C$1.8 billion expansion includes building a new 42-inch diameter diluent/bitumen ("dilbit") pipeline, a new 20-inch diameter products pipeline, tankage and upgrading existing pump stations along the existing pipeline system from the Muskeg River Mine north of Fort McMurray to the Edmonton region. The Corridor pipeline expansion would add an initial 180,000 bpd of dilbit capacity to accommodate the new bitumen production from the Muskeg River Mine. An expansion of the Corridor pipeline system has been completed in 2006 increasing the dilbit capacity to 278,000 bpd by upgrading existing pump station facilities. By 2009, the dilbit capacity of the Corridor system is expected to be approximately 460,000 bpd. An application for the Corridor pipeline expansion project was filed with the Alberta Energy Utilities Board and Alberta Environment on December 22, 2005, and approval was received in August 2006. Construction of the Corridor pipeline expansion began in November 2006 as the shippers have received definitive approval of their Muskeg River Mine expansion.

On December 22, 2005, the FERC issued a Notice of Proposed Rulemaking to amend its regulations by establishing two new methods for obtaining market-based rates for underground natural gas storage services. First, the FERC proposed to modify its market power analysis to better reflect competitive alternatives to storage. Doing so would allow a storage applicant to include other storage services as well as non-storage products such as pipeline capacity, local production, or liquefied natural gas supply in its calculation of market concentration and its analysis of market share. Second, the FERC proposed to modify its regulations to permit the FERC to allow market-based rates for new storage facilities even if the storage provider is unable to show that it lacks market power, provided the FERC finds that the market-based rates are in the public interest and necessary to encourage the construction of needed storage capacity and that customers are adequately protected from the abuse of market power. On June 19, 2006, the FERC issued Order 678 allowing for broader market-based pricing of storage services. The rule expands the alternatives that can be considered in evaluating competition, provides that market-based pricing may be available even when market power is present (if market-based pricing is needed to stimulate development) and treats expansions of existing facilities similar to new facilities. The order became effective July 27, 2006. On November 16, 2006, the FERC issued its order on rehearing, clarifying that it would consider whether additional reporting is appropriate on a case-by-case basis to ensure that customer protections remain adequate over time, but denying rehearing in all other respects.

In a letter filed on December 8, 2005, NGPL requested that the Office of the Chief Accountant confirm that NGPL's proposed accounting treatment to capitalize the costs incurred in a one-time pipeline rehabilitation project that will address stress corrosion cracking on portions of NGPL's pipeline system is appropriate. The rehabilitation project will be conducted over a five-year period. On June 5, 2006, in Docket No. AC 06-18, the FERC ruled on NGPL's request to capitalize pipeline rehabilitation costs. The ruling states that NGPL must expense rather than capitalize the majority of the costs. NGPL can continue to capitalize the costs of pipe replacement and coating but costs to assess the integrity of pipe must be expensed.

On November 22, 2004, the FERC issued a Notice of Inquiry seeking comments on its policy of selective discounting. Specifically, the FERC requested parties to submit comments and respond to inquiries regarding the FERC's practice of permitting pipelines to adjust their ratemaking throughput downward in rate cases to reflect discounts given by pipelines for competitive reasons – when the discount is given to meet competition from another gas pipeline. By an order issued May 31, 2005, the FERC reaffirmed its existing policy on selective discounting by interstate pipelines without change. Several entities filed for rehearing; however, by an order issued on November 17, 2005, the FERC denied all requests for rehearing. On January 9, 2006, a petition for judicial review of the FERC's May 31, 2005 and November 17, 2005 orders was filed by the Northern Municipal Distributor Group/Midwest Region Gas Task Force Association.

On November 5, 2004, the FERC issued a notice of proposed accounting release that would require FERC jurisdictional entities to recognize costs incurred in performing pipeline assessments that are a part of a pipeline integrity management program as maintenance expense in the period incurred. The proposed accounting ruling is in response to the FERC's finding of diverse practices within the pipeline industry in accounting for pipeline assessment activities. The proposed ruling would standardize these practices. Specifically, the proposed ruling clarifies the distinction between costs for a "one-time rehabilitation project to extend the useful life of the system," which could be capitalized, and costs for an "on-going inspection and testing or maintenance program," which would be accounted for as maintenance and charged to expense in the period incurred.

On June 30, 2005, the FERC issued an order providing guidance to the industry on accounting for costs associated with pipeline integrity management requirements. The order is effective prospectively from January 1, 2006. Under the order, the costs to be expensed as incurred include those to: prepare a plan to implement the program; identify high consequence areas; develop and maintain a record keeping system; and inspect affected pipeline segments. The costs of modifying the pipeline to permit in-line inspections, such as installing pig launchers and receivers, are to be capitalized, as are certain costs associated with developing or enhancing computer software or adding or replacing other items of plant. The Interstate Natural Gas Association of America, referred to in this report as INGAA, sought rehearing of the FERC's June 30 order. On September 19, 2005, the FERC denied INGAA's request for rehearing. On December 15, 2005, INGAA filed with the United States Court of Appeals for the District of Columbia Circuit, referred to in this report as D.C. Circuit, in Docket No. 05-1426, a petition for review asking the Court whether the FERC lawfully ordered that interstate pipelines must treat certain costs incurred in complying with the Pipeline Safety Improvement Act of 2002, along with related pipeline testing costs, as expenses rather than capital items for purposes of complying with the FERC's regulatory accounting regulations. On May 10, 2006, the Court issued an order establishing a briefing schedule. Under the schedule, INGAA filed its initial brief on June 23, 2006. Both the FERC's and INGAA's reply briefs have been filed. Oral argument at the D.C. Circuit was held January 16, 2007.

Due to the implementation of this FERC order on January 1, 2006, which caused the Kinder Morgan FERC-regulated natural gas pipelines to expense certain pipeline integrity management program costs that would have been capitalized, operating expenses for NGPL and Kinder Morgan Energy Partners' Kinder Morgan Interstate Gas Transmission LLC increased $13.7 million and $0.5 million, respectively, in 2006 compared to 2005. Also, beginning in the third quarter of 2006, Kinder Morgan Energy Partners' Texas intrastate natural gas pipeline group and the operations included in Kinder Morgan Energy Partners' Products Pipelines and CO_2 business segments began recognizing certain costs incurred as part of their pipeline integrity management program as operating expense in the period incurred, and in addition, recorded an expense for costs previously capitalized during the first six months of 2006. For the year 2006 compared to 2005, this change resulted in operating expense increases of approximately $4.4 million for the Texas intrastate gas group, $20.1 million for the Products Pipelines business segment, and $1.7 million for the CO_2 business segment. Combined, this change did not have a material impact on our financial position, results of operations, or cash flows for the 2006 annual period and did not have any material effect on prior periods. In addition, due to the fact that these amounts were not capitalized, but instead charged to expense, Kinder Morgan Energy Partners' sustaining capital expenditures were reduced by similar amounts.

On November 25, 2003, the FERC issued Order No. 2004, adopting new Standards of Conduct to become effective February 9, 2004. Every interstate natural gas pipeline was required to file a compliance plan by that date and was required to be in full compliance with the Standards of Conduct by June 1, 2004. The primary change from existing regulation was to make such standards applicable to an interstate pipeline's interaction with many more affiliates (termed "Energy Affiliates"), including intrastate/Hinshaw natural gas pipelines (in general, a Hinshaw pipeline is a pipeline that receives gas at or within a state boundary, is regulated by an agency of that state, and all the natural gas it transports is consumed within that state), processors and gatherers and any company involved in natural gas or electric markets (such as electric generators and electric or natural gas marketers) even if they do not ship on the affiliated interstate natural gas pipeline. Local distribution companies ("LDCs") were excluded, however, if they do not make sales to customers not physically attached to their system. The Standards of Conduct require, among other things, separate staffing of interstate natural gas pipelines and their Energy Affiliates (but certain support functions and senior management at the central corporate level may be shared) and strict limitations on communications from an interstate natural gas pipeline to an Energy Affiliate.

On April 16, 2004, the FERC issued Order No. 2004-A. The FERC extended the effective date of the new Standards of Conduct from June 1, 2004, to September 1, 2004, and provided further clarification in several areas.

On February 19, 2004, the Kinder Morgan interstate pipelines filed exemption requests with the FERC so that affiliated Hinshaw and intrastate natural gas pipelines would not be considered Energy Affiliates. On July 21, 2004, the Kinder Morgan interstate pipelines filed additional joint requests asking for limited exemptions from certain requirements of FERC Order No. 2004 and asking for an extension of the deadline for full compliance with Order No. 2004 until 90 days after the FERC has completed action on the pipelines' various rehearing and exemption requests. The pipelines also requested that Rocky Mountain Natural Gas Company, one of Kinder Morgan, Inc.'s wholly owned subsidiaries, be classified as an exempt LDC for purposes of Order No. 2004. These exemptions requested relief from the independent functioning and information disclosure requirements of Order No. 2004. The exemption requests proposed to treat as Energy Affiliates within the meaning of Order No. 2004 two groups of employees, (i) individuals in the Choice Gas Commodity Group within Kinder Morgan, Inc.'s Retail operations and (ii) commodity sales and purchasing personnel within Kinder Morgan Energy Partners' Texas intrastate natural gas operations. Order No. 2004 regulations governing relationships between interstate pipelines and their Energy Affiliates would apply to relationships with these two discrete groups. Under these proposals, certain critical operating functions could continue to be shared.

On August 2, 2004, the FERC issued Order No. 2004-B. In this order, the FERC extended the effective date of the new Standards of Conduct from September 1, 2004 to September 22, 2004.

On September 20, 2004, the FERC issued an order that conditionally granted the July 21, 2004 joint requests for limited exemptions from the requirements of the Standards of Conduct described above. In that order, the FERC directed the Kinder Morgan interstate pipelines to submit compliance plans regarding these exemptions within 30 days. These compliance plans were filed on October 19, 2004 and set out certain steps taken by the Kinder Morgan interstate pipelines to assure that employees in the Choice Gas Commodity Group within Kinder Morgan Inc.'s Retail operations and the commodity sales and purchasing personnel of Kinder Morgan Energy Partners' Texas intrastate operations do not have access to restricted interstate natural gas pipeline information or receive preferential treatment as to interstate natural gas pipeline services.

The Kinder Morgan interstate pipelines implemented compliance with the Standards of Conduct as of September 22, 2004, subject to the exemptions described above. Compliance includes, among other things, the posting of compliance procedures and organizational information for each interstate pipeline on its internet website, the posting of discount and tariff discretion information and the implementation of independent functioning for Energy Affiliates not covered by the prior paragraph (electric and natural gas gathering, processing or production affiliates).

On December 21, 2004, the FERC issued Order No. 2004-C, an order granting rehearing on certain issues and also clarifying certain provisions in the previous orders. The primary impact on the Kinder Morgan interstate pipelines from Order No. 2004-C is the granting of rehearing allowing LDCs to participate in hedging activity related to on-system sales and still qualify for exemption from being an Energy Affiliate.

By an order issued on April 19, 2005, the FERC accepted the compliance plans filed by the Kinder Morgan interstate pipelines without modification, but subject to further clarification as to the intrastate group in three areas: (i) further description of the matters the shared transmission function personnel may discuss with the commodity sales and purchasing personnel within Kinder Morgan Energy Partners' Texas intrastate operations; (ii) additional posting of organizational information about the commodity sales and purchasing personnel within Kinder Morgan Energy Partners' Texas intrastate operations; and (iii) clarification that the President of Kinder Morgan Energy Partners' intrastate pipeline group has received proper training and will not be a conduit for improperly sharing transmission or customer information with the commodity sales and purchasing personnel within Kinder Morgan Energy Partners' Texas intrastate natural gas operations. The FERC also approved treatment of Rocky Mountain Natural Gas Company as an exempt LDC.

The Kinder Morgan interstate pipelines made a compliance filing on May 18, 2005, which filing was accepted by the FERC on July 20, 2006.

On November 17, 2006, the D.C. Circuit, in Docket No. 04-1183, vacated FERC Order Nos. 2004, 2004-A, 2004-B, 2004-C, and 2004-D as applied to natural gas pipelines, and remanded these same orders back to the FERC. On January 9, 2007, the FERC issued an Interim Rule, effective January 9, 2007, in response to the D.C. Circuit's action. In the Interim Rule, the FERC readopted the Standards of Conduct, but revised or clarified with respect to issues which had been appealed to the D.C. Circuit. Specifically, the following changes were made: (1) the Standards of Conduct apply only to the relationship between interstate natural gas transmission pipelines and their Marketing Affiliates, not their Energy Affiliates; (2) all Risk Management personnel can be shared; (3) the requirement to post discretionary tariff actions was eliminated, but interstate natural gas pipelines must still maintain a log of discretionary tariff waivers; (4) lawyers providing legal advice may be shared employees; and (5) new interstate natural gas transmission pipelines are not subject to the Standards of Conduct until they commence service. The FERC clarified that all exemptions and waivers issued under Order No. 2004 remain in effect. On January 18, 2007, the FERC issued a notice of proposed rulemaking soliciting comments on whether or not the Interim Rule should be made permanent for natural gas transmission providers.

Natural Gas Pipeline Expansion Filings

TransColorado Pipeline

On June 23, 2006, in FERC Docket No. CP06-401-000, TransColorado Gas Transmission Company ("TransColorado") filed an application for authorization to construct and operate certain facilities comprising its proposed "Blanco-Meeker Expansion Project." Upon implementation, this project will facilitate the transportation of up to 250,000 Dth/per day of natural gas from the Blanco Hub area in San Juan County, New Mexico through TransColorado's existing interstate pipeline for delivery to Rockies Express Pipeline LLC at an existing point of interconnection located at the Meeker Hub in Rio Blanco County, Colorado.

Kinder Morgan Louisiana Pipeline

On September 8, 2006, in FERC Docket No. CP06-449, Kinder Morgan Louisiana Pipeline LLC filed an application with the FERC requesting approval to construct and operate the Kinder Morgan Louisiana Pipeline, an interstate natural gas pipeline. The pipeline will extend approximately 135 miles from Cheniere's Sabine Pass liquefied natural gas terminal in Cameron Parish, Louisiana, to various delivery points in Louisiana and will provide interconnects with many other natural gas pipelines, including NGPL. The project is supported by fully subscribed capacity and long-term customer commitments with Chevron and Total. The entire approximately $500 million project is expected to be in service in the second quarter of 2009. Also on September 8, 2006, in FERC Docket No. CP06-448, NGPL requested authorization to abandon, by long-term operating lease, 200,000 Dth per day of firm capacity to Kinder Morgan Louisiana Pipeline LLC in Cameron Parish, Louisiana, where NGPL will interconnect with the project.

On January 26, 2007, the FERC issued a draft Environmental Impact Statement ("EIS") which addresses the potential environmental effects of the construction and operation of the Kinder Morgan Louisiana Pipeline. The draft EIS was prepared to satisfy the requirements of the National Environmental Policy Act. It concluded that approval of the proposed project would have limited adverse environmental impact. The public will have until March 19, 2007 to file comments on the draft, which will be taken into account in the preparation of the final EIS.

Kinder Morgan Illinois Pipeline

On September 14, 2006, in FERC Docket No. CP06-455, Kinder Morgan Illinois Pipeline filed seeking a certificate from the FERC to acquire long-term lease capacity on NGPL and build facilities to supply transportation service for Peoples Gas Light and Coke Co., who has signed a 10-year agreement for all the capacity. The $13.3 million project would have a capacity of 360,000 Dth/day and is expected to be operational by the 2007-08 winter heating season. Also on September 14, 2006, in FERC Docket No. CP06-454, NGPL requested authorization to abandon, by long-term operating lease, 360,000 Dth per day to Kinder Morgan Illinois Pipeline LLC.

NGPL Louisiana Line

On October 10, 2006, in FERC Docket No. CP07-3, NGPL filed seeking approval to expand its Louisiana Line by 200,000 Dth/day. This $66 million project is supported by five-year agreements that fully subscribe the additional capacity.

Terasen Gas Squamish to Whistler Pipeline

In June 2006, the BCUC approved an application from Terasen Gas Inc. to build a 50-kilometer natural gas pipeline from Squamish to Whistler. The estimated C$42 million project, which includes the cost of retrofitting utilities customers' gas-fired appliances from propane to natural gas use, will replace an aging propane system. Construction on this project is being integrated with and performed by the contractor performing the highway upgrades to Whistler in advance of the 2010 Winter Olympics. We expect full service to be available to Whistler by November 2008.

Currently, there are no material proceedings challenging the base rates (which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for) on any of our natural gas pipeline systems. Nonetheless, shippers on our pipelines do have rights to challenge the rates we charge under certain circumstances prescribed by applicable statutes and regulations. There can be no assurance that we will not face challenges to the rates we receive for services on our pipeline systems in the future. In addition, since many of our assets are subject to regulation, we are subject to potential future changes in applicable rules and regulations that may have an adverse effect on our business, cash flows, financial position or results of operations.

19. Litigation, Environmental and Other Contingencies

Federal Energy Regulatory Commission Proceedings

SFPP, L.P.

SFPP, L.P. is the subsidiary limited partnership that owns Kinder Morgan Energy Partners' Pacific operations, excluding CALNEV Pipe Line LLC and related terminals acquired from GATX Corporation. Tariffs charged by SFPP are subject to certain proceedings at the FERC, including shippers' complaints regarding interstate rates on Kinder Morgan Energy Partners' Pacific operations' pipeline systems.

OR92-8, et al. proceedings. FERC Docket No. OR92-8-000 *et al.*, is a consolidated proceeding that began in September 1992 and includes a number of shipper complaints against certain rates and practices on SFPP's East Line (from El Paso, Texas to Phoenix, Arizona) and West Line (from Los Angeles, California to Tucson, Arizona), as well as SFPP's gathering enhancement fee at Watson Station in Carson, California. The complainants in the case are El Paso Refinery, L.P. (which settled with SFPP in 1996), Chevron Products Company, Navajo Refining Company (now Navajo Refining Company, L.P.), ARCO Products Company (now part of BP West Coast Products, LLC), Texaco Refining and Marketing Inc., Refinery Holding Company LP (now named Western Refining Company, L.P.), Mobil Oil Corporation (now part of ExxonMobil Oil Corporation) and Tosco Corporation (now part of ConocoPhillips Company). The FERC has ruled that the complainants have the burden of proof in this proceeding.

In this Note, we refer to SFPP, L.P. as SFPP; CALNEV Pipe Line LLC as Calnev; Chevron Products Company as Chevron; Navajo Refining Company, L.P. as Navajo; ARCO Products Company as ARCO; BP West Coast Products, LLC as BP WCP; Texaco Refining and Marketing Inc. as Texaco; Western Refining Company, L.P. as Western Refining; Mobil Oil Corporation as Mobil; ExxonMobil Oil Corporation as ExxonMobil; Tosco Corporation as Tosco; and ConocoPhillips Company as ConocoPhillips.

A FERC administrative law judge held hearings in 1996, and issued an initial decision in September 1997. The initial decision held that all but one of SFPP's West Line rates were "grandfathered" under the Energy Policy Act of 1992 and therefore deemed to be just and reasonable; it further held that complainants had failed to prove "substantially changed circumstances" with respect to those rates and that the rates therefore could not be challenged in the Docket No. OR92-8 *et al.* proceedings, either for the past or prospectively. However, the initial decision also made rulings generally adverse to SFPP on certain cost of service issues relating to the evaluation of East Line rates, which are not "grandfathered" under the Energy Policy Act. Those issues included the capital structure to be used in computing SFPP's "starting rate base," the level of income tax allowance SFPP may include in rates and the recovery of civil and regulatory litigation expenses and certain pipeline reconditioning costs incurred by SFPP. The initial decision also held SFPP's Watson Station gathering enhancement service was subject to FERC jurisdiction and ordered SFPP to file a tariff for that service.

The FERC subsequently reviewed the initial decision, and issued a series of orders in which it adopted certain rulings made by the administrative law judge, changed others and modified a number of its own rulings on rehearing. Those orders began in January 1999, with FERC Opinion No. 435, and continued through June 2003.

The FERC affirmed that all but one of SFPP's West Line rates are "grandfathered" and that complainants had failed to satisfy the threshold burden of demonstrating "substantially changed circumstances" necessary to challenge those rates. The FERC further held that the one West Line rate that was not grandfathered did not need to be reduced. The FERC consequently dismissed all complaints against the West Line rates in Docket Nos. OR92-8 *et al.* without any requirement that SFPP reduce, or pay any reparations for, any West Line rate.

The FERC initially modified the initial decision's ruling regarding the capital structure to be used in computing SFPP's "starting rate base" to be more favorable to SFPP, but later reversed that ruling. The FERC also made certain modifications to the calculation of the income tax allowance and other cost of service components, generally to SFPP's disadvantage.

On multiple occasions, the FERC required SFPP to file revised East Line rates based on rulings made in the FERC's various orders. SFPP was also directed to submit compliance filings showing the calculation of the revised rates, the potential reparations for each complainant and in some cases potential refunds to shippers. SFPP filed such revised East Line rates and compliance filings in March 1999, July 2000, November 2001 (revised December 2001), October 2002 and February 2003 (revised March 2003). Most of those filings were protested by particular SFPP shippers. The FERC has held that certain of the rates SFPP filed at the FERC's directive should be reduced retroactively and/or be subject to refund; SFPP has challenged the FERC's authority to impose such requirements in this context.

While the FERC initially permitted SFPP to recover certain of its litigation, pipeline reconditioning and environmental costs, either through a surcharge on prospective rates or as an offset to potential reparations, it ultimately limited recovery in such a way that SFPP was not able to make any such surcharge or take any such offset. Similarly, the FERC initially ruled that SFPP would not owe reparations to any complainant for any period prior to the date on which that party's complaint was filed, but ultimately held that each complainant could recover reparations for a period extending two years prior to the filing of its complaint (except for Navajo, which was limited to one month of pre-complaint reparations under a settlement agreement with SFPP's predecessor). The FERC also ultimately held that SFPP was not required to pay reparations or refunds for Watson Station gathering enhancement fees charged prior to filing a FERC tariff for that service.

In April 2003, SFPP paid complainants and other shippers reparations and/or refunds as required by FERC's orders. In August 2003, SFPP paid shippers an additional refund as required by FERC's most recent order in the Docket No. OR92-8 *et al.* proceedings. SFPP made aggregate payments of $44.9 million in 2003 for reparations and refunds pursuant to a FERC order.

Beginning in 1999, SFPP, the complainants and intervenor Ultramar Diamond Shamrock Corporation (now part of Valero Energy Corporation) filed petitions for review of FERC's Docket OR92-8 *et al.* orders in the D.C. Circuit. Certain of those petitions were dismissed by the D.C. Circuit as premature, and the remaining petitions were held in abeyance pending completion of agency action. However, in December 2002, the D.C. Circuit returned to its active docket all petitions to review the FERC's orders in the case through November 2001 and severed petitions regarding later FERC orders. The severed orders were held in abeyance for later consideration. In this Note, we refer to Ultramar Diamond Shamrock Corporation as Ultramar and we refer to Valero Energy Corporation as Valero.

Briefing in the D.C. Circuit was completed in August 2003, and oral argument took place on November 12, 2003. On July 20, 2004, the D.C. Circuit issued its opinion in *BP West Coast Products, LLC v. Federal Energy Regulatory Commission*, No. 99-1020, On Petitions for Review of Orders of the Federal Energy Regulatory Commission (*BP West Coast Products, LLC v.*

FERC), addressing in part the tariffs of SFPP. Among other things, the court's opinion vacated the income tax allowance portion of the FERC opinion and the order allowing recovery in SFPP's rates for income taxes and remanded to the FERC this and other matters for further proceedings consistent with the court's opinion. In reviewing a series of FERC orders involving SFPP, the D.C. Circuit held, among other things, that the FERC had not adequately justified its policy of providing an oil pipeline limited partnership with an income tax allowance equal to the proportion of its limited partnership interests owned by corporate partners. By its terms, the portion of the opinion addressing SFPP only pertained to SFPP and was based on the record in that case.

The D.C. Circuit held that, in the context of the Docket No. OR92-8, *et al.* proceedings, all of SFPP's West Line rates were grandfathered other than the charge for use of SFPP's Watson Station gathering enhancement facility and the rate for turbine fuel movements to Tucson under SFPP Tariff No. 18. It concluded that the FERC had a reasonable basis for concluding that the addition of a West Line origin point at East Hynes, California did not involve a new "rate" for purposes of the Energy Policy Act. It rejected arguments from West Line Shippers that certain protests and complaints had challenged West Line rates prior to the enactment of the Energy Policy Act.

The D.C. Circuit also held that complainants had failed to satisfy their burden of demonstrating substantially changed circumstances, and therefore could not challenge grandfathered West Line rates in the Docket No. OR92-8 *et al.* proceedings. It specifically rejected arguments that other shippers could "piggyback" on the special Energy Policy Act exception permitting Navajo to challenge grandfathered West Line rates, which Navajo had withdrawn under a settlement with SFPP. The court remanded to the FERC the changed circumstances issue "for further consideration" in light of the court's decision regarding SFPP's tax allowance. While the FERC had previously held in the OR96-2 proceeding (discussed following) that the tax allowance policy should not be used as a stand-alone factor in determining when there have been substantially changed circumstances, the FERC's May 4, 2005 income tax allowance policy statement (discussed following) may affect how the FERC addresses the changed circumstances and other issues remanded by the court.

The D.C. Circuit upheld the FERC's rulings on most East Line rate issues; however, it found the FERC's reasoning inadequate on some issues, including the tax allowance.

The D.C. Circuit held the FERC had sufficient evidence to use SFPP's December 1988 stand-alone capital structure to calculate its starting rate base as of June 1985; however, it rejected SFPP arguments that would have resulted in a higher starting rate base.

The D.C. Circuit accepted the FERC's treatment of regulatory litigation costs, including the limitation of recoverable costs and their offset against "unclaimed reparations" – that is, reparations that could have been awarded to parties that did not seek them. The court also accepted the FERC's denial of any recovery for the costs of civil litigation by East Line shippers against SFPP based on the 1992 re-reversal of the six-inch line between Tucson and Phoenix. However, the court did not find adequate support for the FERC's decision to allocate the limited litigation costs that SFPP was allowed to recover in its rates equally between the East Line and the West Line, and ordered the FERC to explain that decision further on remand.

The D.C. Circuit held the FERC had failed to justify its decision to deny SFPP any recovery of funds spent to recondition pipe on the East Line, for which SFPP had spent nearly $6 million between 1995 and 1998. It concluded that the FERC's reasoning was inconsistent and incomplete, and remanded for further explanation, noting that "SFPP's shippers are presently enjoying the benefits of what appears to be an expensive pipeline reconditioning program without sharing in any of its costs."

The D.C. Circuit affirmed the FERC's rulings on reparations in all respects. It held the *Arizona Grocery* doctrine did not apply to orders requiring SFPP to file "interim" rates, and that "FERC only established a final rate at the completion of the OR92-8 proceedings." It held that the Energy Policy Act did not limit complainants' ability to seek reparations for up to two years prior to the filing of complaints against rates that are not grandfathered. It rejected SFPP's arguments that the FERC should not have used a "test period" to compute reparations, that it should have offset years in which there were underrecoveries against those in which there were overrecoveries, and that it should have exercised its discretion against awarding any reparations in this case.

The D.C. Circuit also rejected:

- Navajo's argument that its prior settlement with SFPP's predecessor did not limit its right to seek reparations;
- Valero's argument that it should have been permitted to recover reparations in the Docket No. OR92-8 *et al.* proceedings rather than waiting to seek them, as appropriate, in the Docket No. OR96-2 *et al.* proceedings;
- arguments that the former ARCO and Texaco had challenged East Line rates when they filed a complaint in January 1994 and should therefore be entitled to recover East Line reparations; and
- Chevron's argument that its reparations period should begin two years before its September 1992 protest regarding

the six-inch line reversal rather than its August 1993 complaint against East Line rates.

On September 2, 2004, BP WCP, Chevron, ConocoPhillips and ExxonMobil filed a petition for rehearing and rehearing *en banc* asking the D.C. Circuit to reconsider its ruling that West Line rates were not subject to investigation at the time the Energy Policy Act was enacted. On September 3, 2004, SFPP filed a petition for rehearing asking the court to confirm that the FERC has the same discretion to address on remand the income tax allowance issue that administrative agencies normally have when their decisions are set aside by reviewing courts because they have failed to provide a reasoned basis for their conclusions. On October 4, 2004, the D.C. Circuit denied both petitions without further comment.

On November 2, 2004, the D.C. Circuit issued its mandate remanding the Docket No. OR92-8 proceedings to the FERC. SFPP and shipper parties subsequently filed various pleadings with the FERC regarding the proper nature and scope of the remand proceedings. On December 2, 2004, the FERC issued a Notice of Inquiry and opened a new proceeding (Docket No. PL05-5) to consider how broadly the D.C. Circuit's ruling on the tax allowance issue in *BP West Coast Products, LLC, v. FERC* should affect the range of entities the FERC regulates. The FERC sought comments on whether the court's ruling applies only to the specific facts of the SFPP proceeding, or also extends to other capital structures involving partnerships and other forms of ownership. Comments were filed by numerous parties, including the Kinder Morgan interstate natural gas pipelines, in the first quarter of 2005. On May 4, 2005, the FERC adopted a policy statement in Docket No. PL05-5, providing that all entities owning public utility assets - oil and gas pipelines and electric utilities - would be permitted to include an income tax allowance in their cost-of-service rates to reflect the actual or potential income tax liability attributable to their public utility income, regardless of the form of ownership. Any tax pass-through entity seeking an income tax allowance would have to establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income. The FERC expressed the intent to implement its policy in individual cases as they arise. The FERC's decision in Docket No. PL05-5 has been appealed to the D.C. Circuit (discussed further below in relation to the OR96-2 proceedings). Oral argument was held on December 12, 2006, but the D.C. Circuit has not issued an opinion.

On December 17, 2004, the D.C. Circuit issued orders directing that the petitions for review relating to FERC orders issued after November 2001 in OR92-8, which had previously been severed from the main D.C. Circuit docket, should continue to be held in abeyance pending completion of the remand proceedings before the FERC. Petitions for review of orders issued in other FERC dockets have since been returned to the court's active docket (discussed further below in relation to the OR96-2 proceedings).

On January 3, 2005, SFPP filed a petition for a writ of *certiorari* asking the United States Supreme Court to review the D.C. Circuit's ruling that the *Arizona Grocery* doctrine does not apply to "interim" rates, and that "FERC only established a final rate at the completion of the OR92-8 proceedings." BP WCP and ExxonMobil also filed a petition for *certiorari*, on December 30, 2004, seeking review of the D.C. Circuit's ruling that there was no pending investigation of West Line rates at the time of enactment of the Energy Policy Act (and thus that those rates remained grandfathered). On April 6, 2005, the Solicitor General filed a brief in opposition to both petitions on behalf of the FERC and United States, and Navajo, ConocoPhillips, Ultramar, Valero and Western Refining filed an opposition to SFPP's petition. SFPP filed a reply to those briefs on April 18, 2005. On May 16, 2005, the Supreme Court issued orders denying the petitions for *certiorari* filed by SFPP and by BP WCP and ExxonMobil.

On June 1, 2005, the FERC issued its Order on Remand and Rehearing, referred to in this report as the June 2005 Order, which addressed issues in both the OR92-8 and OR96-2 proceedings (discussed following).

With respect to the OR92-8 proceedings, the June 2005 Order ruled on several issues that had been remanded by the D.C. Circuit in *BP West Coast Products, LLC v. FERC*. With respect to the income tax allowance, the FERC held that its May 4, 2005 policy statement would apply in the OR92-8 and OR96-2 proceedings and that SFPP "should be afforded an income tax allowance on all of its partnership interests to the extent that the owners of those interests had an actual or potential tax liability during the periods at issue." It directed SFPP and opposing parties to file briefs regarding the state of the existing record on those questions and the need for further proceedings. Those filings are described below in the discussion of the OR96-2 proceedings. The FERC held that SFPP's allowable regulatory litigation costs in the OR92-8 proceedings should be allocated between the East Line and the West Line based on the volumes carried by those lines during the relevant period. In doing so, it reversed its prior decision to allocate those costs between the two lines on a 50-50 basis. The FERC affirmed its prior decision to exclude SFPP's pipeline reconditioning costs from the cost of service in the OR92-8 proceedings, but stated that SFPP will have an opportunity to justify much of those reconditioning expenses in the OR96-2 proceedings. The FERC deferred further proceedings on the non-grandfathered West Line turbine fuel rate until completion of its review of the initial decision in Phase II of the OR96-2 proceedings. The FERC held that SFPP's contract charge for use of the Watson Station gathering enhancement facilities was not grandfathered and required further proceedings before an administrative law judge to determine the reasonableness of that charge. Those proceedings are discussed further below.

Petitions for review of the June 2005 Order by the D.C. Circuit have been filed by SFPP, Navajo, Western Refining, BP WCP, ExxonMobil, Chevron, ConocoPhillips, Ultramar and Valero. SFPP moved to intervene in the review proceedings brought by the other parties. The proceedings before the D.C. Circuit are addressed further below.

On December 16, 2005, the FERC issued its Order on Initial Decision and on Certain Remanded Cost Issues, referred to in this report as the December 2005 Order, which provided further guidance regarding application of the FERC's income tax allowance policy in this case, which is discussed below in connection with the OR96-2 proceedings. The December 2005 Order required SFPP to submit a revised East Line cost of service filing following FERC's rulings regarding the income tax allowance and the ruling in the June 2005 Order regarding the allocation of litigation costs. SFPP filed interim East Line rates effective May 1, 2006 using the lower of the revised OR92-8 (1994 test year) or OR96-2 (1999 test year) rates, as adjusted for indexing through April 30, 2006. The December 2005 Order also required SFPP to calculate costs-of-service for West Line turbine fuel movements based on both a 1994 and 1999 test year and to file interim turbine fuel rates to be effective May 1, 2006, using the lower of the two test year rates as indexed through April 30, 2006. SFPP was further required to calculate estimated reparations for complaining shippers consistent with the order. As described further below, various parties filed requests for rehearing and petitions for review of the December 2005 Order.

Watson Station proceedings. The FERC's June 2005 Order initiated a separate proceeding regarding the reasonableness of the Watson Station charge. All Watson-related issues in Docket No. OR92-8, Docket No. OR96-2 and other dockets were also consolidated in that proceeding. After discovery and the filing of prepared direct testimony, the procedural schedule was suspended while the parties pursued settlement negotiations.

On May 17, 2006, the parties entered into a settlement agreement and filed an offer of settlement with the FERC. On August 2, 2006, the FERC approved the settlement without modification and directed that it be implemented. Pursuant to the settlement, SFPP filed a new tariff, which took effect September 1, 2006, lowering SFPP's going-forward rate to $0.003 per barrel and including certain volumetric pumping rates. SFPP also paid refunds to all shippers for the period from April 1, 1999 through August 31, 2006. Those refunds were based upon the difference between the Watson Station charge as filed in SFPP's prior tariffs and the reduced charges set forth in the agreement.

On September 28, 2006, SFPP filed a refund report with the FERC, setting forth the refunds that had been paid and describing how the refund calculations were made. ExxonMobil protested the refund report (BP WCP also originally protested the report, but later withdrew its protest). On December 5, 2006, the FERC approved SFPP's refund report with respect to all shippers except ExxonMobil. On December 5, 2006, the FERC remanded the ExxonMobil refund issue to the administrative law Judge for a determination as to whether additional funds were due ExxonMobil; the FERC accepted the refund report as to all other amounts and the recipients contained in the report. In February 2007, SFPP and ExxonMobil reached agreement regarding ExxonMobil's protest of the refund report, and the protest was withdrawn. As of December 31, 2006, SFPP had made aggregate payments, including accrued interest, of $19.1 million.

For the period prior to April 1, 1999, the parties agreed to reserve for briefing issues related to whether shippers are entitled to reparations. To the extent any reparations are owed, the parties agreed on how reparations would be calculated. Initial briefs regarding the reserved legal issues were filed on November 15, 2006. Reply briefs were due on February 8, 2007, with oral argument, if convened, to occur on March 1, 2007. The scheduled issuance date for the initial decision is March 29, 2007.

On January 16, 2007, SFPP and ExxonMobil informed the presiding judge that they had reached a settlement in principle regarding the ExxonMobil refund issue.

Sepulveda proceedings. In December 1995, Texaco filed a complaint at the FERC (Docket No. OR96-2) alleging that movements on SFPP's Sepulveda pipeline (Line Sections 109 and 110) to Watson Station, in the Los Angeles basin, were subject to the FERC's jurisdiction under the Interstate Commerce Act, and claimed that the rate for that service was unlawful. Several other West Line shippers filed similar complaints and/or motions to intervene.

In an August 1997 order, the FERC held that the movements on the Sepulveda pipeline were subject to its jurisdiction. On October 6, 1997, SFPP filed a tariff establishing the initial interstate rate for movements on the Sepulveda pipeline at five cents per barrel. Several shippers protested that rate.

In December 1997, SFPP filed an application for authority to charge a market-based rate for the Sepulveda service, which application was protested by several parties. On September 30, 1998, the FERC issued an order finding that SFPP lacks market power in the Watson Station destination market and set a hearing to determine whether SFPP possessed market power in the origin market.

In December 2000, an administrative law judge found that SFPP possessed market power over the Sepulveda origin market. On February 28, 2003, the FERC issued an order upholding that decision. SFPP filed a request for rehearing of that order on March 31, 2003. The FERC denied SFPP's request for rehearing on July 9, 2003.

As part of its February 28, 2003 order denying SFPP's application for market-based ratemaking authority, the FERC remanded to the ongoing litigation in Docket No. OR96-2, *et al.* the question of whether SFPP's current rate for service on the Sepulveda pipeline is just and reasonable. Hearings in this proceeding were held in February and March 2005. SFPP asserted various defenses against the shippers' claims for reparations and refunds, including the existence of valid contracts with the shippers and grandfathering protection. In August 2005, the presiding administrative law judge issued an initial decision finding that for the period from 1993 to November 1997 (when the Sepulveda FERC tariff went into effect) the Sepulveda rate should have been lower. The administrative law judge recommended that SFPP pay reparations and refunds for alleged overcollections. SFPP filed in October 2005 a brief to the FERC taking exception to this and other portions of the initial decision.

On December 8, 2006, the FERC issued its order on the initial decision in the Sepulveda proceeding. The FERC affirmed the administrative law judge's decision that the Sepulveda rate should have been lower but disagreed with the administrative law judge's rulings on some aspects of the equity cost-of-capital, income tax allowances, and the recovery of SFPP's litigation costs. The December 8 order directed SFPP to file revised Sepulveda rates for 1995 and 1996 and to submit a compliance filing estimating reparations and refunds. The compliance filing, related tariff adjustments, and requests for rehearing were made on February 7, 2007.

OR96-2; OR97-2; OR98-1. et al. proceedings. In October 1996, Ultramar filed a complaint at the FERC (Docket No. OR97-2) challenging SFPP's West Line rates, claiming they were unjust and unreasonable and no longer subject to grandfathering. In October 1997, ARCO, Mobil and Texaco filed a complaint at the FERC (Docket No. OR98-1) challenging the justness and reasonableness of all of SFPP's interstate rates, raising claims against SFPP's East and West Line rates similar to those that have been at issue in Docket Nos. OR92-8, *et al*. discussed above, but expanding them to include challenges to SFPP's grandfathered interstate rates from the San Francisco Bay area to Reno, Nevada and from Portland to Eugene, Oregon - the North Line and Oregon Line. In November 1997, Ultramar filed a similar, expanded complaint (Docket No. OR98-2). Tosco filed a similar complaint in April 1998. The shippers seek both reparations and prospective rate reductions for movements on all of SFPP's lines. The FERC accepted the complaints and consolidated them into one proceeding (Docket No. OR96-2, *et al.*), but held them in abeyance pending a FERC decision on review of the initial decision in Docket Nos. OR92-8, *et al.*

In a companion order to Opinion No. 435, the FERC gave the complainants an opportunity to amend their complaints in light of Opinion No. 435, which the complainants did in January 2000. In August 2000, Navajo and Western Refining filed complaints against SFPP's East Line rates and Ultramar filed an additional complaint updating its pre-existing challenges to SFPP's interstate pipeline rates. These complaints were consolidated with the ongoing proceeding in Docket No. OR96-2, *et al*.

A hearing in this consolidated proceeding was held from October 2001 to March 2002. A FERC administrative law judge issued his initial decision in June 2003. The initial decision found that, for the years at issue, the complainants had shown substantially changed circumstances for rates on SFPP's West, North and Oregon Lines and for SFPP's fee for gathering enhancement service at Watson Station and thus found that those rates should not be "grandfathered" under the Energy Policy Act of 1992. The initial decision also found that most of SFPP's rates at issue were unjust and unreasonable.

On March 26, 2004, the FERC issued an order on the Phase I initial decision, referred to in this report as the March 2004 Order. The March 2004 Order reversed the initial decision by finding that SFPP's rates for its North and Oregon Lines should remain "grandfathered" and amended the initial decision by finding that SFPP's West Line rates (i) to Yuma, Tucson and CalNev, as of 1995, and (ii) to Phoenix, as of 1997, should no longer be "grandfathered" and are not just and reasonable. The FERC upheld these findings in its June 2005 Order, although it appears to have found substantially changed circumstances as to SFPP's West Line rates on a somewhat different basis than in the March 2004 Order. The March 2004 Order did not address prospective West Line rates and whether reparations were necessary. As discussed below, those issues have been addressed in the FERC's December 2005 Order on Phase II issues. The March 2004 Order also did not address the "grandfathered" status of the Watson Station fee, noting that it would address that issue once it was ruled on by the D.C. Circuit in its review of the FERC's Opinion No. 435 orders; as noted above, the FERC held in its June 2005 Order that the Watson Station fee is not grandfathered. Several of the participants in the proceeding requested rehearing of the March 2004 Order. The FERC denied those requests in its June 2005 Order. In addition, several participants, including SFPP, filed petitions with the D.C. Circuit for review of the March 2004 Order. In August 2005, the FERC and SFPP jointly moved that the D.C. Circuit hold the petitions for review of the March 2004 and June 2005 Orders in abeyance due to the pendency of further action before the FERC on income tax allowance issues. In December 2005, the D.C. Circuit denied this motion and placed the petitions seeking review of the two orders on the active docket. Initial briefs to the Court were filed May 30, 2006, and final briefs were filed October 19, 2006. Oral argument was held on December 12, 2006.

On July 24, 2006, the FERC filed with the D.C. Circuit a motion for voluntary partial remand, requesting that the portion of the March 2004 and June 2005 Orders in which the FERC removed grandfathering protection from SFPP's West Line rates and affirmed such protection for the North Line and Oregon Line rates be returned to the FERC for reconsideration in light of arguments presented by SFPP and other parties in their initial briefs. In response to the FERC's remand motion, SFPP filed on

August 1, 2006 to reinstate its West Line rates at the previous, grandfathered level effective August 2, 2006, and asked for FERC approval of such reinstatement on the ground that, pending the FERC's reconsideration of its grandfathering rulings, the prior grandfathered rate level is the lawful rate. On August 17, 2006, the D.C. Circuit denied without prejudice the FERC's motion for voluntary partial remand. In light of this denial, on August 31, 2006, the FERC issued an order rejecting SFPP's August 1, 2006 filing seeking reinstatement of SFPP's grandfathered West Line rates.

In the June 2005 Order, the FERC directed SFPP to file a brief addressing whether the records developed in the OR92-8 and OR96-2 cases were sufficient to determine SFPP's entitlement to include an income tax allowance in its rates under the FERC's new policy statement. On June 16, 2005, SFPP filed its brief reviewing the pertinent records in the pending cases and applicable law and demonstrating its entitlement to a full income tax allowance in its interstate rates. SFPP's opponents in the two cases filed reply briefs contesting SFPP's presentation. It is not possible to predict with certainty the ultimate resolution of this issue, particularly given that the FERC's policy statement and its decision in these cases have been appealed to the federal courts.

On September 9, 2004, the presiding administrative law judge in OR96-2 issued his initial decision in the Phase II portion of this proceeding, recommending establishment of prospective rates and the calculation of reparations for complaining shippers with respect to the West Line and East Line, relying upon cost of service determinations generally unfavorable to SFPP.

In the December 2005 Order, the FERC addressed issues remanded by the D.C. Circuit in the Docket No. OR92-8 proceeding (discussed above) and the Phase II cost of service issues arising from the initial decision in Phase II of OR96-2, including income tax allowance issues arising from the briefing directed by the FERC's June 2005 Order. The FERC directed SFPP to submit compliance filings and revised tariffs by February 28, 2006 (as extended to March 7, 2006) which were to address, in addition to the OR92-8 matters discussed above, the establishment of interim West Line rates based on a 1999 test year, indexed forward to a May 1, 2006 effective date and estimated reparations. The FERC also resolved favorably a number of methodological issues regarding the calculation of SFPP's income tax allowance under the May 2005 policy statement and, in its compliance filings, directed SFPP to submit further information establishing the amount of its income tax allowance for the years at issue in the OR92-8 and OR96-2 proceedings.

SFPP and Navajo have filed requests for rehearing of the December 2005 Order. ExxonMobil, BP WCP, Chevron, Ultramar, and ConocoPhillips have filed petitions for review of the December 2005 Order with the D.C. Circuit. On February 13, 2006, the FERC issued an order, referred to in this report as the February 2006 Order, addressing the pending rehearing requests, granting the majority of SFPP's requested changes regarding reparations and methodological issues. SFPP, Navajo, and other parties have filed petitions for review of the December 2005 and February 2006 Orders with the D.C. Circuit. On July 31, 2006, the D.C. Circuit held the appeals of these orders in abeyance pending further FERC action.

On March 7, 2006, SFPP filed its compliance filings and revised tariffs. Various shippers filed protests of the tariffs. On April 21, 2006, various parties submitted comments challenging aspects of the costs of service and rates reflected in the compliance filings and tariffs. On April 28, 2006, the FERC issued an order accepting SFPP's tariffs lowering its West Line and East Line rates in conformity with the FERC's December 2005 and February 2006 Orders. On May 1, 2006, these lower tariff rates became effective. The FERC indicated that a subsequent order would address the issues raised in the comments. On May 1, 2006, SFPP filed reply comments.

In accordance with the FERC's December 2005 Order, rate reductions were implemented on May 1, 2006. We assume that reparations and accrued interest thereon will be paid no earlier than the second quarter of 2007; however, the timing, and nature, of any rate reductions and reparations that may be ordered will likely be affected by the final disposition of the application of the FERC's new policy statement on income tax allowances to Kinder Morgan Energy Partners' Pacific operations in the FERC Docket Nos. OR92-8, OR96-2, and IS05-230 proceedings.

In 2005, Kinder Morgan Energy Partners recorded an accrual of $105.0 million for an expense attributable to an increase in its reserves related to its rate case liability. Kinder Morgan Energy Partners had previously estimated the combined annual impact of the rate reductions and the payment of reparations sought by shippers would be approximately 15 cents of distributable cash flow per unit. Based on our review of the December 2005 and the February 2006 Orders, and subject to the ultimate resolution of these issues in SFPP's compliance filings and subsequent judicial appeals, we now expect the total annual impact on Kinder Morgan Energy Partners will be less than 15 cents per unit. We estimate that the actual, partial year impact on Kinder Morgan Energy Partners' 2006 distributable cash flow was approximately $15.7 million and the partial year impact on our 2006 earnings per share was approximately $0.04 per share.

We are not able to predict with certainty the final outcome of the pending FERC proceedings involving SFPP, should they be carried through to their conclusion, or whether we can reach a settlement with some or all of the complainants. The final outcome will depend, in part, on the outcomes of the appeals of these proceedings and the OR92-8, *et al.* proceedings taken by SFPP, complaining shippers, and an intervenor.

<u>*Chevron complaint OR02-4 and OR03-5 proceedings*</u>. On February 11, 2002, Chevron, an intervenor in the Docket No. OR96-2, *et al*. proceeding, filed a complaint against SFPP in Docket No. OR02-4 along with a motion to consolidate the complaint with the Docket No. OR96-2, *et al*. proceeding. On May 21, 2002, the FERC dismissed Chevron's complaint and motion to consolidate. Chevron filed a request for rehearing, which the FERC dismissed on September 25, 2002. In October 2002, Chevron filed a request for rehearing of the FERC's September 25, 2002 Order, which the FERC denied on May 23, 2003. On July 1, 2003, Chevron filed a petition for review of this denial at the D.C. Circuit.

On July 2, 2003, Chevron filed another complaint against SFPP (OR03-5) - substantially similar to its previous complaint – and moved to consolidate the complaint with the Docket No. OR96-2, *et al*. proceeding. Chevron requested that this new complaint be treated as if it were an amendment to its complaint in Docket No. OR02-4, which was previously dismissed by the FERC. By this request, Chevron sought to, in effect, back-date its complaint, and claim for reparations, to February 2002. SFPP answered Chevron's complaint on July 22, 2003, opposing Chevron's requests. On October 28, 2003, the FERC accepted Chevron's complaint, but held it in abeyance pending the outcome of the Docket No. OR96-2, *et al.* proceeding. The FERC denied Chevron's request for consolidation and for back-dating. On November 21, 2003, Chevron filed a petition for review of the FERC's October 28, 2003 order at the D.C. Circuit.

On August 18, 2003, SFPP filed a motion to dismiss Chevron's petition for review in OR02-4 on the basis that Chevron lacks standing to bring its appeal and that the case is not ripe for review. Chevron answered on September 10, 2003. SFPP's motion was pending, when the D.C. Circuit, on December 8, 2003, granted Chevron's motion to hold the case in abeyance pending the outcome of the appeal of the Docket No. OR92-8, *et al.* proceeding. On January 8, 2004, the D.C. Circuit granted Chevron's motion to have its appeal of the FERC's decision in OR03-5 consolidated with Chevron's appeal of the FERC's decision in the OR02-4 proceeding. Following motions to dismiss by the FERC and SFPP, on December 10, 2004, the Court dismissed Chevron's petition for review in Docket No. OR03-5 and set Chevron's appeal of the FERC's orders in OR02-4 for briefing. On January 4, 2005, the Court granted Chevron's request to hold such briefing in abeyance until after final disposition of the OR96-2 proceeding. Chevron continues to participate in the Docket No. OR96-2 *et al*. proceeding as an intervenor.

<u>*Airlines OR04-3 proceeding*</u>. On September 21, 2004, America West Airlines, Inc., Southwest Airlines, Co., Northwest Airlines, Inc. and Continental Airlines, Inc. (collectively, the "Airlines") filed a complaint against SFPP at the FERC. The Airlines' complaint alleges that the rates on SFPP's West Line and SFPP's charge for its gathering enhancement service at Watson Station are not just and reasonable. The Airlines seek rate reductions and reparations for two years prior to the filing of their complaint. BP WCP and ExxonMobil, ConocoPhillips, Navajo and Chevron all filed timely motions to intervene in this proceeding. Valero Marketing and Supply Company, referred to in this Note as Valero Marketing, filed a motion to intervene one day after the deadline. SFPP answered the Airlines' complaint on October 12, 2004. On October 29, 2004, the Airlines filed a response to SFPP's answer and on November 12, 2004, SFPP replied to the Airlines' response. In March and June 2005, the Airlines filed motions seeking expedited action on their complaint, and in July 2005, the Airlines filed a motion seeking to sever issues related to the Watson Station gathering enhancement fee from the OR04-3 proceeding and consolidate them in the proceeding regarding the justness and reasonableness of that fee that the FERC docketed as part of the June 2005 Order. In August 2005, the FERC granted the Airlines' motion to sever and consolidate the Watson Station fee issues.

<u>*OR05-4 and OR05-5 proceedings*</u>. On December 22, 2004, BP WCP and ExxonMobil filed a complaint against SFPP at the FERC, which the FERC docketed as OR05-4. The complaint alleges that SFPP's interstate rates are not just and reasonable, that certain rates found grandfathered by the FERC are not entitled to such status, and, if so entitled, that "substantially changed circumstances" have occurred, removing such protection. The complainants seek rate reductions and reparations for two years prior to the filing of their complaint and ask that the complaint be consolidated with the Airlines' complaint in the OR04-3 proceeding. ConocoPhillips, Navajo and Western Refining all filed timely motions to intervene in this proceeding. SFPP answered the complaint on January 24, 2005.

On December 29, 2004, ConocoPhillips filed a complaint against SFPP at the FERC, which the FERC docketed as OR05-5. The complaint alleges that SFPP's interstate rates are not just and reasonable, that certain rates found grandfathered by the FERC are not entitled to such status, and, if so entitled, that "substantially changed circumstances" have occurred, removing such protection. ConocoPhillips seeks rate reductions and reparations for two years prior to the filing of their complaint. BP WCP and ExxonMobil, Navajo and Western Refining all filed timely motions to intervene in this proceeding. SFPP answered the complaint on January 28, 2005.

On February 25, 2005, the FERC consolidated the complaints in Docket Nos. OR05-4 and OR05-5 and held them in abeyance until after the conclusion of the various pending SFPP proceedings, deferring any ruling on the validity of the complaints. On March 28, 2005, BP WCP and ExxonMobil requested rehearing of one aspect of the February 25, 2005 order; they argued that any tax allowance matters in these proceedings could not be decided in, or as a result of, the FERC's inquiry into income tax allowance in Docket No. PL05-5. On June 8, 2005, the FERC denied the request for rehearing.

Consolidated Complaints. On February 13, 2006, the FERC consolidated the complaints in Docket Nos. OR03-5, OR05-4, and OR05-5 and set for hearing the portions of those complaints attacking SFPP's North Line and Oregon Line rates, which rates remain grandfathered under the Energy Policy Act. A procedural schedule was established in that consolidated proceeding. The FERC also indicated in its order that it would address the remaining portions of these complaints in the context of its disposition of SFPP's compliance filings in the OR92-8/OR96-2 proceedings. On September 5, 2006, the presiding administrative law judge suspended the procedural schedule in Docket No. OR03-5 pending a decision by the D.C. Circuit regarding various issues before the court that directly impact the Docket No. OR03-5 proceeding.

Docket No. OR07-1. On December 1, 2006, Tesoro Refining and Marketing Company, referred to in this Note as Tesoro, filed a complaint against SFPP challenging the rate that SFPP charges for interstate transportation on its North Line. Tesoro seeks rate reductions and reparations for two years prior to the filing of the complaint. SFPP filed an answer to the complaint on January 2, 2007. The FERC has not yet issued a ruling in Docket No. OR07-1.

Docket No. OR07-2. On December 12, 2006, Tesoro filed a complaint against SFPP alleging that SFPP's interstate West Line rates are unjust and unreasonable. Tesoro seeks rate reductions and reparations for two years prior to the filing of the complaint. SFPP filed an answer to the complaint on January 11, 2007. The FERC has not yet issued a ruling in Docket No. OR07-2.

Docket No. OR07-3. BP WCP, Chevron, ExxonMobil, Tesoro, and Valero Marketing filed a complaint and motion for summary disposition on December 20, 2006 in Docket No. OR07-3 that challenged the justness and reasonableness of SFPP's North Line index rate increase in Docket No. IS05-327. The complaint requests refunds and reparations for shipments made under the indexed rates from July 1, 2005. SFPP filed an answer to this complaint on January 9, 2007. The FERC has not yet issued a ruling in Docket No. OR07-3.

Docket No. OR07-4. On January 5, 2007, BP WCP, ExxonMobil, and Chevron filed a complaint against SFPP, Kinder Morgan G.P., Inc., and Kinder Morgan, Inc. alleging that none of SFPP's current rates or terms of service are just and reasonable under the Interstate Commerce Act. Complainants seek reparations with interest for the two years prior to the filing of this complaint. The answer to this complaint was due on February 5, 2007.

Docket No. OR07-6. ConocoPhillips filed a complaint on January 9, 2007 that challenged the justness and reasonableness of SFPP's North Line index rate increases in Docket Nos. IS05-327 and IS06-356. The complaint requests refunds and reparations for shipments made under the indexed rates from July 1, 2005. SFPP filed an answer to ConocoPhillips' complaint, and the FERC has not yet issued a ruling in Docket No. OR07-6.

North Line rate case, IS05-230 proceeding. In April 2005, SFPP filed to increase its North Line interstate rates to reflect increased costs, principally due to the installation of replacement pipe between Concord and Sacramento, California, referred to in this Note as the Concord to Sacramento Segment. Under FERC regulations, SFPP was required to demonstrate that there was a substantial divergence between the revenues generated by its existing North Line rates and its increased costs. SFPP's rate increase was protested by various shippers and accepted subject to refund by the FERC. A hearing was held in January and February 2006, and the presiding administrative law judge issued his initial decision on September 25, 2006.

The initial decision held that SFPP should be allowed to include in its rate base all costs associated with relocating the Concord to Sacramento Segment, but to include only 14/20ths of the cost of constructing the new line; it further held that the FERC's policy statement on income tax allowance is inconsistent with the D.C. Circuit's decision in *BP West Coast Products, LLC v. FERC* and that, therefore, SFPP should be allowed no income tax allowance. While the initial decision held that SFPP could recover its litigation costs, it otherwise made rulings generally adverse to SFPP on cost of service issues. These issues included the capital structure to be used in computing SFPP's "starting rate base," treatment of SFPP's accumulated deferred income tax account, costs of debt and equity, as well as allocation of overhead. Briefs on exceptions were filed on October 25, 2006, and briefs opposing exceptions were filed on November 14, 2006. The FERC has not yet reviewed the initial decision, and it is not possible to predict the outcome of FERC or appellate review.

East Line rate case, IS06-283 proceeding. In May 2006, SFPP filed to increase its East Line interstate rates to reflect increased costs, principally due to the installation of replacement pipe between El Paso, Texas and Tucson, Arizona, significantly increasing the East Line's capacity. Under FERC regulations, SFPP was required to demonstrate that there was a substantial divergence between the revenues generated by its existing East Line rates and its increased costs. SFPP's rate increase was protested by various shippers and accepted subject to refund by the FERC. The FERC established an investigation and hearing before an administrative law judge. On November 22, 2006, the chief judge suspended the procedural schedule in this docket pending resolution of certain issues pending before the D.C. Circuit.

Index Increases, IS06-356, IS05-327. On May 27, 2005, SFPP filed to increase certain rates pursuant to the FERC's indexing methodology. Various shippers protested, and the FERC accepted and suspended all but one of the filed tariffs, subject to SFPP's filing of a revised Page 700 of its FERC Form 6 and subject to the outcome of various proceedings involving SFPP at the FERC. BP WCP and ExxonMobil filed for rehearing and challenged the revised Page 700 filed by SFPP. On December

12, 2005, the FERC denied the request for rehearing; this decision is currently on appeal before the D.C. Circuit. Initial briefs and final briefs have been filed, and oral argument was held on February 15, 2007.

On May 30, 2006, SFPP also filed to increase certain interstate rates pursuant to the FERC's indexing methodology. This filing was protested, but the FERC determined that SFPP's tariff filing was consistent with the FERC's regulations. Certain shippers requested rehearing, which the FERC granted for further consideration on August 21, 2006. The FERC's order has been appealed to the D.C. Circuit. On August 31, 2006, the FERC filed a motion with the D.C. Circuit to hold the case in abeyance, and SFPP and BP WCP subsequently intervened. The Court has not yet issued a ruling on the motions filed by the FERC, SFPP, and BP WCP. On December 6, 2006, the FERC rescinded the July 1, 2006 index increase to SFPP's East Line rates and ordered SFPP to refund the East Line index increase to shippers back to the effective date of July 1, 2006. On January 5, 2007, SFPP filed a request for rehearing of the FERC's December 6, 2006 order, but the FERC has not yet ruled on the request for rehearing.

ULSD Surcharge, IS06-508. On August 11, 2006, SFPP filed tariffs to include a per barrel Ultra Low Sulfur Diesel (referred to in this Note as ULSD) recovery fee on all diesel products. Various shippers protested the filing, and, on September 8, 2006, the FERC accepted the tariffs, subject to refund, and established hearing procedures. SFPP has withdrawn the tariffs containing the ULSD surcharge, and the FERC vacated the procedural schedule in this docket on October 17, 2006.

Motions to Compel Payment of Interim Damages. On November 21, 2006, a number of SFPP shippers filed a motion with the FERC to compel SFPP and/or Kinder Morgan G.P., Inc. and/or Kinder Morgan, Inc. to pay interim damages to shippers or alternatively to put such damages in escrow pending FERC resolution of the various complaint and protest proceedings pending against SFPP. SFPP filed its response to this motion on December 6, 2006. Also on December 6, 2006, the complainants in Docket No. OR04-3 filed their own motion for interim damages and/or escrow, and SFPP filed a response to this second motion on December 21, 2006. The FERC has not yet taken any action with respect to these pending motions.

Calnev Pipe Line LLC

Docket No. IS06-296. On May 22, 2006, Calnev filed to increase its interstate rates pursuant to the FERC's indexing methodology applicable to oil pipelines. Calnev's filing was protested by ExxonMobil, claiming that Calnev was not entitled to an indexing increase in its rates based on its cost of service. Calnev answered the protest. On June 29, 2006, the FERC accepted and suspended the filing, subject to refund, permitting the increased rates to go into effect on July 1, 2006. The FERC found that Calnev's indexed rates exceeded its change in costs to a degree that warranted establishing an investigation and hearing. However, the FERC initially directed the parties to attempt to reach a settlement of the dispute before a FERC settlement judge. The settlement process is proceeding.

Docket No. OR07-5. On January 8, 2007, ExxonMobil filed a complaint against Calnev, Kinder Morgan G.P., Inc., and Kinder Morgan, Inc. In the Calnev complaint, ExxonMobil alleges that none of Calnev's current rates or terms of service are just and reasonable under the Interstate Commerce Act. ExxonMobil seeks reparations with interest for the two years prior to the filing of the Calnev complaint. Calnev filed an answer to the Calnev complaint on February 7, 2007.

California Public Utilities Commission Proceeding

ARCO, Mobil and Texaco filed a complaint against SFPP with the California Public Utilities Commission, referred to in this Note as the CPUC, on April 7, 1997. The complaint challenges rates charged by SFPP for intrastate transportation of refined petroleum products through its pipeline system in the State of California and requests prospective rate adjustments. On October 1, 1997, the complainants filed testimony seeking prospective rate reductions aggregating approximately $15 million per year.

On August 6, 1998, the CPUC issued its decision dismissing the complainants' challenge to SFPP's intrastate rates. On June 24, 1999, the CPUC granted limited rehearing of its August 1998 decision for the purpose of addressing the proper ratemaking treatment for partnership tax expenses, the calculation of environmental costs and the public utility status of SFPP's Sepulveda Line and its Watson Station gathering enhancement facilities. In pursuing these rehearing issues, complainants sought prospective rate reductions aggregating approximately $10 million per year.

On March 16, 2000, SFPP filed an application with the CPUC seeking authority to justify its rates for intrastate transportation of refined petroleum products on competitive, market-based conditions rather than on traditional, cost-of-service analysis.

On April 10, 2000, ARCO and Mobil filed a new complaint with the CPUC asserting that SFPP's California intrastate rates are not just and reasonable based on a 1998 test year and requesting the CPUC to reduce SFPP's rates prospectively. The amount of the reduction in SFPP rates sought by the complainants is not discernible from the complaint.

The rehearing complaint was heard by the CPUC in October 2000, and the April 2000 complaint and SFPP's market-based application were heard by the CPUC in February 2001. All three matters stand submitted as of April 13, 2001, and resolution of these submitted matters may occur at any time.

In October 2002, the CPUC issued a resolution, referred to in this report as the Power Surcharge Resolution, approving a 2001 request by SFPP to raise its California rates to reflect increased power costs. The resolution approving the requested rate increase also required SFPP to submit cost data for 2001, 2002, and 2003, and to assist the CPUC in determining whether SFPP's overall rates for California intrastate transportation services are reasonable. The resolution reserves the right to require refunds, from the date of issuance of the resolution, to the extent the CPUC's analysis of cost data to be submitted by SFPP demonstrates that SFPP's California jurisdictional rates are unreasonable in any fashion. On February 21, 2003, SFPP submitted the cost data required by the CPUC, which submittal was protested by Valero Marketing, Ultramar, BP WCP, ExxonMobil and Chevron. Issues raised by the protest, including the reasonableness of SFPP's existing intrastate transportation rates, were the subject of evidentiary hearings conducted in December 2003 and may be resolved by the CPUC at any time.

With regard to the CPUC complaints and the Power Surcharge Resolution, we currently believe the complainants/protestants seek approximately $31 million in prospective annual tariff reductions. Based upon CPUC practice and procedure, which precludes refunds or reparations in complaints in which the complainants challenge the reasonableness of rates previously found reasonable by the CPUC (as is the case with the two pending complaints contesting the reasonableness of SFPP's rates) except for matters which have been expressly reserved by the CPUC for further consideration (as is the case with respect to the reasonableness of the rate charged for use of the Watson Station gathering enhancement facilities), we currently believe that complainants/protestants are seeking approximately $15 million in refunds/reparations. We are not able to quantify the potential extent to which the CPUC could determine that SFPP's existing California rates are unreasonable.

SFPP also has various, pending ratemaking matters before the CPUC that are unrelated to the above-referenced complaints and the Power Surcharge Resolution. On November 22, 2004, SFPP filed an application with the CPUC requesting a $9 million annual increase in existing intrastate rates to reflect the in-service date of SFPP's replacement and expansion of its Concord-to-Sacramento pipeline. The requested rate increase, which automatically became effective as of December 22, 2004 pursuant to California Public Utilities Code Section 455.3, is being collected subject to refund, pending resolution of protests to the application by Valero Marketing, Ultramar, BP WCP, ExxonMobil and Chevron. Because no schedule has been established by the CPUC for addressing the issues raised by the contested rate increase application nor does any record exist upon which the CPUC could base a decision, SFPP has no basis for estimating either the prospective rate reductions or the potential refunds at issue or for establishing a date by which the CPUC is likely to render a decision regarding the application.

On January 26, 2006, SFPP filed a request for a rate increase of approximately $5.4 million annually with the CPUC, to be effective as of March 2, 2006. Protests to SFPP's rate increase application have been filed by Tesoro, BP WCP, ExxonMobil, Southwest Airlines Company, Valero Marketing, Ultramar and Chevron, asserting that the requested rate increase is unreasonable. As a consequence of the protests, the related rate increases are being collected subject to refund. Because no schedule has been established by the CPUC for addressing the issues raised by the contested rate increase application nor does any record exist upon which the CPUC could base a decision, SFPP has no basis for estimating either the prospective rate reductions or the potential refunds at issue or for establishing a date by which the CPUC is likely to render a decision regarding the application.

On August 25, 2006, SFPP filed an application to increase rates by approximately $0.5 million annually to recover costs incurred to comply with revised Ultra Low Sulfur Diesel regulations and to offset the revenue loss associated with reduction of the Watson Station Volume Deficiency Charge (intrastate) by increasing rates on a system-wide basis by approximately $3.1 million annually to be effective as of October 5, 2006. Protests to SFPP's rate increase application have been filed by Tesoro, BP WCP, ExxonMobil, Southwest Airlines Company, Valero Marketing, Ultramar and Chevron, asserting that the requested rate increase is unreasonable. As a consequence of the protests, the related rate increases are being collected subject to refund. Because no schedule has been established by the CPUC for addressing the issues raised by the contested rate increase application, nor does any record exist upon which the CPUC could base a decision, SFPP has no basis for estimating either the prospective rate reductions, or the potential refunds at issue, or for establishing a date by which the CPUC is likely to render a decision regarding the application.

All of the referenced pending matters before the CPUC have been consolidated and assigned to a single Administrative Law Judge. The Administrative Law Judge has referred the matters to mediation, and the mediation process is pending.

With regard to the Power Surcharge Resolution, the November 2004 rate increase application, the January 2006 rate increase application and the August 2006 rate increase application, SFPP believes the submission of the required, representative cost data required by the CPUC indicates that SFPP's existing rates for California intrastate services remain reasonable and that no rate reductions or refunds are justified.

We believe that the resolution of such matters will not have a material adverse effect on our business, financial position, results of operations or cash flows.

Other Regulatory Matters

In addition to the matters described above, we may face additional challenges to our rates in the future. Shippers on our pipelines do have rights to challenge the rates we charge under certain circumstances prescribed by applicable regulations. There can be no assurance that we will not face challenges to the rates we receive for services on our pipeline systems in the future or that such challenges will not have a material adverse effect on our business, financial position, results of operations or cash flows. In addition, since many of our assets are subject to regulation, we are subject to potential future changes in applicable rules and regulations that may have a material adverse effect on our business, financial position, results of operations or cash flows.

Carbon Dioxide Litigation

Shores and First State Bank of Denton Lawsuits

Kinder Morgan CO_2 Company, L.P., Kinder Morgan G.P., Inc., and Cortez Pipeline Company were among the named defendants in Shores, et al. v. Mobil Oil Corp., et al., No. GC-99-01184 (Statutory Probate Court, Denton County, Texas filed December 22, 1999) and First State Bank of Denton, et al. v. Mobil Oil Corp., et al., No. 8552-01 (Statutory Probate Court, Denton County, Texas filed March 29, 2001). These cases were originally filed as class actions on behalf of classes of overriding royalty interest owners (Shores) and royalty interest owners (Bank of Denton) for damages relating to alleged underpayment of royalties on carbon dioxide produced from the McElmo Dome Unit. Although classes were initially certified at the trial court level, appeals resulted in the decertification and/or abandonment of the class claims. On February 22, 2005, the trial judge dismissed both cases for lack of jurisdiction. Some of the individual plaintiffs in these cases re-filed their claims in new lawsuits (discussed below).

Armor/Reddy Lawsuit

On May 13, 2004, William Armor, one of the former plaintiffs in the Shores matter whose claims were dismissed by the Court of Appeals for improper venue, filed a new case alleging the same claims for underpayment of royalties against the same defendants previously sued in the Shores case, including Kinder Morgan CO_2 Company, L.P. and Kinder Morgan Energy Partners, L.P. Armor v. Shell Oil Company, et al., No. 04-03559 (14th Judicial District Court, Dallas County, Texas filed May 13, 2004). Defendants filed their answers and special exceptions on June 4, 2004. The case is currently set for trial on June 11, 2007.

On May 20, 2005, Josephine Orr Reddy and Eastwood Capital, Ltd., two of the former plaintiffs in the Bank of Denton matter, filed a new case in Dallas state district court alleging the same claims for underpayment of royalties. Reddy and Eastwood Capital, Ltd. v. Shell Oil Company, et al., No. 05-5021 (193rd Judicial District Court, Dallas County, Texas filed May 20, 2005). The defendants include Kinder Morgan CO_2 Company, L.P. and Kinder Morgan Energy Partners, L.P. On June 23, 2005, the plaintiff in the Armor lawsuit filed a motion to transfer and consolidate the Reddy lawsuit with the Armor lawsuit. On June 28, 2005, the court in the Armor lawsuit granted the motion to transfer and consolidate and ordered that the Reddy lawsuit be transferred and consolidated into the Armor lawsuit. The defendants filed their answer and special exceptions on August 10, 2005. The consolidated Armor/Reddy case is currently set for trial on June 11, 2007.

Bailey and Bridwell Oil Company Harris County/Southern District of Texas Lawsuit

Shell CO_2 Company, Ltd., predecessor to Kinder Morgan CO_2 Company, L.P., is among the named counter-claim defendants in the case originally filed as Shell Western E&P Inc. v. Gerald O. Bailey and Bridwell Oil Company; No. 98-28630 (215th Judicial District Court, Harris County, Texas filed June 17, 1998) (the "Bailey State Court Action"). The counter-claim plaintiffs are overriding royalty interest owners in the McElmo Dome Unit and have sued seeking damages for underpayment of royalties on carbon dioxide produced from the McElmo Dome Unit. In the Bailey State Court Action, the counter-claim plaintiffs asserted claims for fraud/fraudulent inducement, real estate fraud, negligent misrepresentation, breach of fiduciary duty, breach of contract, negligence, negligence per se, unjust enrichment, violation of the Texas Securities Act, and open account. The trial court in the Bailey State Court Action granted a series of summary judgment motions filed by the counter-claim defendants on all of the counter-plaintiffs' counter-claims except for the fraud-based claims. In 2004, one of the counter-plaintiffs (Gerald Bailey) amended his counter-suit to allege purported claims as a private relator under the False Claims Act and antitrust claims. The federal government elected to not intervene in the False Claims Act counter-suit. On March 24, 2005, Bailey filed a notice of removal, and the case was transferred to federal court. Shell Western E&P Inc. v. Gerald O. Bailey and Bridwell Oil Company, No. H-05-1029 (S.D. Tex., Houston Division removed March 24, 2005) (the "Bailey Houston Federal Court Action"). Also on March 24, 2005, Bailey filed an instrument under seal in the Bailey Houston Federal Court Action that was later determined to be a motion to transfer venue of that case to the federal district court of Colorado, in which Bailey and two other plaintiffs filed another suit against Kinder Morgan CO_2 Company, L.P.

asserting claims under the False Claims Act. The Houston federal district judge ordered that Bailey take steps to have the False Claims Act case pending in Colorado transferred to the Bailey Houston Federal Court Action, and also suggested that the claims of other plaintiffs in other carbon dioxide litigation pending in Texas should be transferred to the Bailey Houston Federal Court Action. In response to the court's suggestion, the case of Gary Shores et al. v. ExxonMobil Corp. et al., No. 05-1825 (S.D. Tex., Houston Division) was consolidated with the Bailey Houston Federal Court Action on July 18, 2005. That case, in which the plaintiffs assert claims for McElmo Dome royalty underpayment, includes Kinder Morgan CO_2 Company, L.P., Kinder Morgan Energy Partners, L.P., and Cortez Pipeline Company as defendants. Bailey requested the Houston federal district court to transfer the Bailey Houston Federal Court Action to the federal district court of Colorado. Bailey also filed a petition for writ of mandamus in the Fifth Circuit Court of Appeals, asking that the Houston federal district court be required to transfer the case to the federal district court of Colorado. On June 3, 2005, the Fifth Circuit Court of Appeals denied Bailey's petition for writ of mandamus. On June 22, 2005, the Fifth Circuit denied Bailey's petition for rehearing *en banc.* On September 14, 2005, Bailey filed a petition for writ of certiorari in the United States Supreme Court, which the U.S. Supreme Court denied on November 28, 2005. On November 21, 2005, the federal district court in Colorado transferred Bailey's False Claims Act case pending in Colorado to the Houston federal district court. On November 30, 2005, Bailey filed a petition for mandamus seeking to vacate the transfer. The Tenth Circuit Court of Appeals denied the petition on December 19, 2005. The U.S. Supreme Court denied Bailey's petition for writ of certiorari. The Houston federal district court subsequently realigned the parties in the Bailey Houston Federal Court Action and the case is now styled Gerald O. Bailey et al. v. Shell Oil Company et al. Pursuant to the Houston federal district court's order, Bailey and the other realigned plaintiffs have filed amended complaints in which they assert claims for fraud/fraudulent inducement, real estate fraud, negligent misrepresentation, breach of fiduciary and agency duties, breach of contract and covenants, violation of the Colorado Unfair Practices Act, civil theft under Colorado law, conspiracy, unjust enrichment, and open account. Bailey also asserted claims as a private relator under the False Claims Act and for violation of federal and Colorado antitrust laws. The realigned plaintiffs seek actual damages, treble damages, punitive damages, a constructive trust and accounting, and declaratory relief. The Shell and Kinder Morgan defendants, along with Cortez Pipeline Company and ExxonMobil defendants, have filed motions for summary judgment on all claims. No current trial date is set.

Bridwell Oil Company Wichita County Lawsuit

On March 1, 2004, Bridwell Oil Company, one of the named defendants/realigned plaintiffs in the Bailey actions, filed a new matter in which it asserts claims that are virtually identical to the claims it asserts against Shell CO_2 Company, Ltd. in the Bailey lawsuit. Bridwell Oil Co. v. Shell Oil Co. et al., No. 160,199-B (78^{th} Judicial District Court, Wichita County, Texas filed March 1, 2004). The defendants in this action include Kinder Morgan CO_2 Company, L.P., Kinder Morgan Energy Partners, L.P., various Shell entities, ExxonMobil entities, and Cortez Pipeline Company. On June 25, 2004, defendants filed answers, special exceptions, pleas in abatement, and motions to transfer venue back to the Harris County District Court. On January 31, 2005, the Wichita County judge abated the case pending resolution of the Bailey State Court Action. The case remains abated.

Ptasynski Colorado Federal District Court Lawsuit

On April 7, 2006, Harry Ptasynski, one of the plaintiffs in the Colorado federal action filed by Bailey under the False Claims Act (which was transferred to the Bailey Houston Federal Court Action as described above), filed suit against Kinder Morgan G.P., Inc. in Colorado federal district court. Harry Ptasynski v. Kinder Morgan G.P., Inc., No. 06-CV-00651 (LTB) (U.S. District Court for the District of Colorado). Ptasynski, who holds an overriding royalty interest at McElmo Dome, asserted claims for civil conspiracy, violation of the Colorado Organized Crime Control Act, violation of Colorado antitrust laws, violation of the Colorado Unfair Practices Act, breach of fiduciary duty and confidential relationship, violation of the Colorado Payment of Proceeds Act, fraudulent concealment, breach of contract and implied duties to market and good faith and fair dealing, and civil theft and conversion. Ptasynski sought actual damages, treble damages, forfeiture, disgorgement, and declaratory and injunctive relief. The Colorado court transferred the case to Houston federal district court, and Ptasynski subsequently sought to non-suit (voluntarily dismiss) the case. The Houston federal district court granted Ptasynski's request to non-suit. Ptasynski also filed an appeal in the Tenth Circuit seeking to overturn the Colorado court's order transferring the case to Houston federal district court. Harry Ptasynski v. Kinder Morgan G.P., Inc. No. 06-1231 (10^{th} Cir.). Briefing in the appeal was completed on November 27, 2005. No oral argument has been set.

Grynberg Lawsuit

Kinder Morgan CO_2 Company, L.P. and Cortez Pipeline Company were among the named defendants in Celeste C. Grynberg, et al. v. Shell Oil Company, et al., No. 98-CV-43 (Colo. Dist. Ct., Montezuma County filed March 2, 1998). This case involved claims by overriding royalty interest owners in the McElmo Dome and Doe Canyon Units seeking damages for underpayment of royalties on carbon dioxide produced from the McElmo Dome Unit, failure to develop carbon dioxide reserves at the Doe Canyon Unit, and failure to develop hydrocarbons at both McElmo Dome and Doe Canyon. The plaintiffs also possess a small working interest at Doe Canyon. Plaintiffs claimed breaches of contractual and potential fiduciary duties owed by the defendants and also alleged other theories of liability including breach of covenants, civil theft, conversion, fraud/fraudulent concealment, violation of the Colorado Organized Crime Control Act, deceptive trade practices, and violation of the Colorado Antitrust Act. In addition to actual or compensatory damages, plaintiffs sought treble damages, punitive damages, and declaratory relief relating to the Cortez Pipeline tariff and the method of calculating and paying royalties on McElmo Dome carbon dioxide. The Court denied plaintiffs' motion for summary judgment concerning alleged underpayment of McElmo Dome overriding royalties on March 2, 2005. In August 2006, plaintiffs and defendants reached a settlement of all claims. Pursuant to the settlement, the case was dismissed with prejudice on September 27, 2006.

CO_2 Claims Arbitration

Cortez Pipeline Company and Kinder Morgan CO_2 Company, L.P., successor to Shell CO_2 Company, Ltd., were among the named defendants in CO_2 Committee, Inc. v. Shell Oil Co., et al., an arbitration initiated on November 28, 2005. The arbitration arose from a dispute over a class action settlement agreement which became final on July 7, 2003 and disposed of five lawsuits formerly pending in the U.S. District Court, District of Colorado. The plaintiffs in such lawsuits primarily included overriding royalty interest owners, royalty interest owners, and small share working interest owners who alleged underpayment of royalties and other payments on carbon dioxide produced from the McElmo Dome Unit in southwest Colorado. The settlement imposed certain future obligations on the defendants in the underlying litigation. The plaintiff in the arbitration is an entity that was formed as part of the settlement for the purpose of monitoring compliance with the obligations imposed by the settlement agreement. The plaintiff alleged that, in calculating royalty and other payments, defendants used a transportation expense in excess of what is allowed by the settlement agreement, thereby causing alleged underpayments of approximately $12 million. The plaintiff also alleged that Cortez Pipeline Company should have used certain funds to further reduce its debt, which, in turn, would have allegedly increased the value of royalty and other payments by approximately $0.5 million. Defendants denied that there was any breach of the settlement agreement. The arbitration hearing took place in Albuquerque, New Mexico on June 26-30, 2006. On August 7, 2006, the arbitration panel issued its opinion finding that defendants did not breach the settlement agreement. On October 25, 2006, defendants in the arbitration filed an application to confirm the arbitration decision in New Mexico federal district court. On November 6, 2006, the plaintiff in the arbitration filed a motion to vacate the arbitration award in Colorado federal district court. On that same day, the plaintiff in the arbitration filed a motion to dismiss the New Mexico federal district court application for lack of jurisdiction or, alternatively, asked the New Mexico court to stay consideration of the application in favor of its motion to vacate filed in the Colorado federal district court. On January 24, 2007, the Colorado federal district court denied the plaintiff's motion to vacate the arbitration award as moot in light of the pending application to confirm filed by defendants in New Mexico federal district court. On January 29, 2007, the New Mexico federal district court denied the plaintiff's motion to dismiss the New Mexico application to confirm or to stay the New Mexico application.

MMS Notice of Noncompliance and Civil Penalty

On December 20, 2006, Kinder Morgan CO_2 Company, L.P. received a "Notice of Noncompliance and Civil Penalty: Knowing or Willful Submission of False, Inaccurate, or Misleading Information—Kinder Morgan CO_2 Company, L.P., Case No. CP07-001" from the U.S. Department of the Interior, Minerals Management Service, referred to in this report as the MMS. This Notice, and the MMS' position that Kinder Morgan CO_2 Company, L.P. has violated certain reporting obligations, relates to a disagreement between the MMS and Kinder Morgan CO_2 Company, L.P. concerning the approved transportation allowance to be used in valuing McElmo Dome carbon dioxide for purposes of calculating federal royalties. In the Notice of Noncompliance and Civil Penalty, the MMS assesses civil penalties under section 109(d) of the Federal Oil and Gas Royalty Management Act of 1982, which provides that "[a]ny person who – (1) knowingly or willfully prepares, maintains, or submits false, inaccurate, or misleading reports, notices, affidavits, records, data or other written information…shall be liable for a penalty of up to $25,000.00 per violation for each day such violation continues." The Notice of Noncompliance and Civil Penalty assesses a civil penalty of approximately $2.2 million as of December 15, 2006 (based on a penalty of $500.00 per day for each of seventeen alleged violations) for Kinder Morgan CO_2 Company, L.P.'s alleged submission of false, inaccurate, or misleading information relating to the transportation allowance, and federal royalties for CO_2 produced at McElmo Dome, during the period from June 2005 through October 2006. The MMS contends that false, inaccurate, or misleading information was submitted in the seventeen monthly Form 2014s containing remittance advice reflecting the royalty payments for the referenced period. The MMS contends that the 2014s were false, inaccurate or misleading because they reflected Kinder Morgan CO_2 Company, L.P.'s use of the Cortez Pipeline tariff as the transportation allowance. The MMS claims that the Cortez Pipeline tariff is not the proper transportation allowance and that Kinder Morgan CO_2 Company, L.P. should have used its "reasonable actual costs" calculated in accordance with certain federal product valuation regulations as amended effective June 1, 2005. The MMS has not, however, identified any royalty underpayment amount due or otherwise issued an appealable order directing that Kinder Morgan CO_2 Company, L.P. pay additional royalties or calculate the federal government's royalties in a different manner. The MMS also stated that although it considers each line of each 2014 to constitute a separate "violation," it is limiting the violation count to the seventeen monthly 2014s submitted during the June 2005 through October 2006 period. The MMS stated that civil penalties will continue to accrue at the same rate until the alleged violations are corrected. The MMS set a due date of January 20, 2007 for Kinder Morgan CO_2 Company, L.P.'s payment of the $2,234,500.00 in civil penalties, with interest to accrue daily on that amount in the event payment is not made by such date. Kinder Morgan CO_2 Company, L.P. has not paid the penalty. On January 2, 2007, Kinder Morgan CO_2 Company, L.P.

submitted a response to the Notice of Noncompliance and Civil Penalty challenging the assessment in the Office of Hearings and Appeals of the Department of the Interior. On February 1, 2007, Kinder Morgan CO_2 Company, L.P. filed a petition to stay the accrual of penalties until the dispute is resolved. On February 22, 2007, an administrative law judge of the U.S. Department of the Interior issued an order denying Kinder Morgan CO_2 Company, L.P.'s petition to stay the accrual of penalties. Kinder Morgan CO_2 Company, L.P. is reviewing the order of the administrative law judge and evaluating potential appellate options.

Kinder Morgan CO_2 Company, L.P. disputes the Notice of Noncompliance and Civil Penalty for a number of reasons. Kinder Morgan CO_2 Company, L.P. contends that use of the Cortez Pipeline tariff as the transportation allowance for purposes of calculating federal royalties was approved by the MMS in 1984. This approval was later affirmed as open-ended by the Interior Board of Land Appeals in the 1990s. Accordingly, Kinder Morgan CO_2 Company, L.P. has stated to the MMS that its use of the Cortez Pipeline tariff as the approved federal transportation allowance is authorized and proper. Kinder Morgan CO_2 Company, L.P. also disputes the allegation that it has knowingly or willfully submitted false, inaccurate, or misleading information to the MMS. Kinder Morgan CO_2 Company, L.P.'s use of the Cortez Pipeline tariff as the approved federal transportation allowance has been the subject of extensive discussion between the parties. The MMS was, and is, fully apprised of that fact and of the royalty valuation and payment process followed by Kinder Morgan CO_2 Company, L.P. generally.

As noted, the Notice of Noncompliance and Civil Penalty does not purport to identify a royalty underpayment. If, however, the MMS were to assert such a claim, the difference between the federal royalties actually paid in the June 2005 through October 2006 period and those it is thought that the government would urge as due is estimated at approximately $2.7 million. No pre-hearing hearing date or pre-hearing schedule has been set in this matter.

J. Casper Heimann, Pecos Slope Royalty Trust and Rio Petro LTD, individually and on behalf of all other private royalty and overriding royalty owners in the Bravo Dome Carbon Dioxide Unit, New Mexico similarly situated v. Kinder Morgan CO_2 Company, L.P., No. 04-26-CL (8th Judicial District Court, Union County New Mexico)

This case involves a purported class action against Kinder Morgan CO_2 Company, L.P. alleging that it has failed to pay the full royalty and overriding royalty ("royalty interests") on the true and proper settlement value of compressed carbon dioxide produced from the Bravo Dome Unit in the period beginning January 1, 2000. The complaint purports to assert claims for violation of the New Mexico Unfair Practices Act, constructive fraud, breach of contract and of the covenant of good faith and fair dealing, breach of the implied covenant to market, and claims for an accounting, unjust enrichment, and injunctive relief. The purported class is comprised of current and former owners, during the period January 2000 to the present, who have private property royalty interests burdening the oil and gas leases held by the defendant, excluding the Commissioner of Public Lands, the United States of America, and those private royalty interests that are not unitized as part of the Bravo Dome Unit. The plaintiffs allege that they were members of a class previously certified as a class action by the United States District Court for the District of New Mexico in the matter Doris Feerer, et al. v. Amoco Production Company, et al., USDC N.M. Civ. No. 95-0012 (the "Feerer Class Action"). Plaintiffs allege that Kinder Morgan CO_2 Company, L.P.'s method of paying royalty interests is contrary to the settlement of the Feerer Class Action. Kinder Morgan CO_2 Company, L.P. filed a motion to compel arbitration of this matter pursuant to the arbitration provisions contained in the Feerer Class Action settlement agreement, which motion was denied by the trial court. Kinder Morgan CO_2 Company, L.P. appealed that ruling to the New Mexico Court of Appeals. Oral arguments took place before the New Mexico Court of Appeals on March 23, 2006, and the New Mexico Court of Appeals affirmed the district court's order on August 8, 2006. Kinder Morgan CO_2 Company, L.P. filed a petition for writ of certiorari in the New Mexico Supreme Court. The New Mexico Supreme Court granted the petition on October 11, 2006. Kinder Morgan CO_2 Company, L.P. filed its Brief in Chief in the New Mexico Supreme Court on December 12, 2006. No oral argument has been set.

In addition to the matters listed above, audits and administrative inquiries concerning Kinder Morgan CO_2 Company, L.P.'s payments on carbon dioxide produced from the McElmo Dome Unit are currently ongoing. These audits and inquiries involve federal agencies and the State of Colorado.

Commercial Litigation Matters

Union Pacific Railroad Company Easements

SFPP and Union Pacific Railroad Company (the successor to Southern Pacific Transportation Company and referred to in this report as UPRR) are engaged in two proceedings to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for each of the ten-year periods beginning January 1, 1994 and January 1, 2004 (*Southern Pacific Transportation Company vs. Santa Fe Pacific Corporation, SFP Properties, Inc., Santa Fe Pacific Pipelines, Inc., SFPP, L.P., et al.*, Superior Court of the State of California for the County of San Francisco, filed August 31, 1994; and *Union Pacific Railroad Company vs. Santa Fe*

Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. "D", Kinder Morgan G.P., Inc., et al., Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004).

With regard to the first proceeding, covering the ten-year period beginning January 1, 1994, the trial court, on July 16, 2003, set the rent for years 1994 – 2003 at approximately $5.0 million per year as of January 1, 1994, subject to annual inflation increases throughout the ten-year period. On February 23, 2005, the California Court of Appeals affirmed the trial court's ruling, except that it reversed a small portion of the decision and remanded it back to the trial court for determination. On remand, the trial court held that there was no adjustment to the rent relating to the portion of the decision that was reversed, but awarded Southern Pacific Transportation Company interest on rental amounts owing as of May 7, 1997.

In April 2006, SFPP paid UPRR $15.3 million in satisfaction of its rental obligations through December 31, 2003. However, SFPP does not believe that the assessment of interest awarded to Southern Pacific Transportation Company on rental amounts owing as of May 7, 1997 was proper, and SFPP sought appellate review of the interest award. In July 2006, the Court of Appeals disallowed the award of interest.

In addition, SFPP and UPRR are engaged in a second proceeding to determine the extent, if any, to which the rent payable by SFPP for the use of pipeline easements on rights-of-way held by UPRR should be adjusted pursuant to existing contractual arrangements for the ten-year period beginning January 1, 2004 (*Union Pacific Railroad Company vs. Santa Fe Pacific Pipelines, Inc., SFPP, L.P., Kinder Morgan Operating L.P. "D", Kinder Morgan G.P., Inc., et al.,* Superior Court of the State of California for the County of Los Angeles, filed July 28, 2004). SFPP was served with this lawsuit on August 17, 2004. The trial in this matter has commenced and is ongoing.

SFPP and UPRR are also engaged in multiple disputes over the circumstances under which SFPP must pay for a relocation of its pipeline within the UPRR right of way and the safety standards that govern relocations. SFPP believes that it must pay for relocation of the pipeline only when so required by the railroad's common carrier operations, and in doing so, it need only comply with standards set forth in the federal Pipeline Safety Act in conducting relocations. In July 2006, a trial before a judge regarding the circumstances under which SFPP must pay for relocations concluded, and the judge determined in a preliminary statement of decision that SFPP must pay for any relocations resulting from any legitimate business purpose of the UPRR. SFPP expects to appeal any final statement of decision to this effect. In addition, UPRR contends that it has complete discretion to cause the pipeline to be relocated at SFPP's expense at any time and for any reason, and that SFPP must comply with the more expensive American Railway Engineering and Maintenance-of-Way standards. Each party is seeking declaratory relief with respect to its positions regarding relocations.

It is difficult to quantify the effects of the outcome of these cases on SFPP because SFPP does not know UPRR's plans for projects or other activities that would cause pipeline relocations. Even if SFPP is successful in advancing its positions, significant relocations for which SFPP must nonetheless bear the expense (i.e. for railroad purposes, with the standards in the federal Pipeline Safety Act applying) would have an adverse effect on our financial position and results of operations. These effects would be even greater in the event SFPP is unsuccessful in one or more of these litigations.

RSM Production Company, et al. v. Kinder Morgan Energy Partners, L.P., et al. (Cause No. 4519, in the District Court, Zapata County Texas, 49th Judicial District).

On October 15, 2001, Kinder Morgan Energy Partners was served with the First Supplemental Petition filed by RSM Production Corporation on behalf of the County of Zapata, State of Texas and Zapata County Independent School District as plaintiffs. Kinder Morgan Energy Partners was sued in addition to 15 other defendants, including two other Kinder Morgan affiliates. Certain entities Kinder Morgan Energy Partners acquired in the Kinder Morgan Tejas acquisition are also defendants in this matter. The petition alleges that these taxing units relied on the reported volume and analyzed heating content of natural gas produced from the wells located within the appropriate taxing jurisdiction in order to properly assess the value of mineral interests in place. The suit further alleges that the defendants undermeasured the volume and heating content of that natural gas produced from privately owned wells in Zapata County, Texas. The petition further alleges that the County and School District were deprived of ad valorem tax revenues as a result of the alleged undermeasurement of the natural gas by the defendants. On December 15, 2001, the defendants filed motions to transfer venue on jurisdictional grounds. On June 12, 2003, plaintiff served discovery requests on certain defendants. On July 11, 2003, defendants moved to stay any responses to such discovery. On December 18, 2006, plaintiff filed a Notice of Non-Suit with the Zapata County District Court Clerk. With the filing of the non-suit, this matter is concluded.

United States of America, ex rel., Jack J. Grynberg v. K N Energy (Civil Action No. 97-D-1233, filed in the U.S. District Court, District of Colorado).

This action was filed on June 9, 1997 pursuant to the federal False Claims Act and involves allegations of mismeasurement of natural gas produced from federal and Indian lands. The Department of Justice has decided not to intervene in support of the action. The complaint is part of a larger series of similar complaints filed by Mr. Grynberg against 77 natural gas pipelines (approximately 330 other defendants). Certain entities Kinder Morgan Energy Partners acquired in the Kinder Morgan Tejas acquisition are also defendants in this matter. An earlier single action making substantially similar allegations against the pipeline industry was dismissed by Judge Hogan of the U.S. District Court for the District of Columbia on grounds of improper joinder and lack of jurisdiction. As a result, Mr. Grynberg filed individual complaints in various courts throughout the country. In 1999, these cases were consolidated by the Judicial Panel for Multidistrict Litigation, and transferred to the District of Wyoming. The multidistrict litigation matter is called *In Re Natural Gas Royalties Qui Tam Litigation*, Docket No. 1293. Motions to dismiss were filed and an oral argument on the motion to dismiss occurred on March 17, 2000. On July 20, 2000, the United States of America filed a motion to dismiss those claims by Grynberg that deal with the manner in which defendants valued gas produced from federal leases, referred to as valuation claims. Judge Downes denied the defendant's motion to dismiss on May 18, 2001. The United States' motion to dismiss most of plaintiff's valuation claims has been granted by the court. Grynberg has appealed that dismissal to the 10th Circuit, which has requested briefing regarding its jurisdiction over that appeal. Subsequently, Grynberg's appeal was dismissed for lack of appellate jurisdiction. Discovery to determine issues related to the Court's subject matter jurisdiction arising out of the False Claims Act is complete. Briefing has been completed and oral arguments on jurisdiction were held before the Special Master on March 17 and 18, 2005. On May 7, 2003, Grynberg sought leave to file a Third Amended Complaint, which adds allegations of undermeasurement related to carbon dioxide production. Defendants have filed briefs opposing leave to amend. Neither the Court nor the Special Master has ruled on Grynberg's Motion to Amend.

On May 13, 2005, the Special Master issued his Report and Recommendations to Judge Downes in the *In Re Natural Gas Royalties Qui Tam Litigation*, Docket No. 1293. The Special Master found that there was a prior public disclosure of the mismeasurement fraud Grynberg alleged, and that Grynberg was not an original source of the allegations. As a result, the Special Master recommended dismissal of the Kinder Morgan defendants on jurisdictional grounds. On June 27, 2005, Grynberg filed a motion to modify and partially reverse the Special Master's recommendations and the Defendants filed a motion to adopt the Special Master's recommendations with modifications. An oral argument was held on December 9, 2005 on the motions concerning the Special Master's recommendations.

On May 9, 2006, the Kinder Morgan defendants filed a Motion to Dismiss and a Motion for Sanctions. On October 20, 2006, the United States District Court, for the District of Wyoming, issued its Order on Report and Recommendations of Special Master. In its Order, the Court upheld the dismissal of the claims against the Kinder Morgan defendants on jurisdictional grounds, finding that Grynberg's claims are based upon public disclosures and that Grynberg does not qualify as an original source. Grynberg has appealed this Order to the Tenth Circuit Court of Appeals. The mediation office for the Tenth Circuit Court of Appeals is involved and is consulting with the parties regarding possible settlement negotiations and will not issue a procedural schedule until these negotiations are complete. The Coordinated Defendants, which include the Kinder Morgan defendants, filed a Motion for Authorization of Taxation of Costs on December 18, 2006, and a Motion for Fees and Expenses on January 8, 2007. Grynberg filed his response brief to the Kinder Morgan Defendants' Motion to Dismiss and Motion for Sanctions on January 5, 2007. A hearing regarding the Motion for Authorization of Taxation of Costs, Motion for Fees and Expenses, and the Kinder Morgan Defendants' Motion to Dismiss and Motion for Sanctions is scheduled for April 24, 2007.

Weldon Johnson and Guy Sparks, individually and as Representative of Others Similarly Situated v. Centerpoint Energy, Inc. et al., No. 04-327-2 (Circuit Court, Miller County Arkansas).

On October 8, 2004, plaintiffs filed the above-captioned matter against numerous defendants including Kinder Morgan Texas Pipeline L.P.; Kinder Morgan Energy Partners, L.P.; Kinder Morgan G.P., Inc.; KM Texas Pipeline, L.P.; Kinder Morgan Texas Pipeline G.P., Inc.; Kinder Morgan Tejas Pipeline G.P., Inc.; Kinder Morgan Tejas Pipeline, L.P.; Gulf Energy Marketing, LLC; Tejas Gas, LLC; and MidCon Corp. The complaint purports to bring a class action on behalf of those who purchased natural gas from CenterPoint and certain of its affiliates from October 1, 1994 to the date of class certification.

The complaint alleges that CenterPoint Energy, Inc., by and through its affiliates, has artificially inflated the price charged to residential consumers for natural gas that it allegedly purchased from the non-CenterPoint defendants, including the above-listed Kinder Morgan entities. The complaint further alleges that in exchange for CenterPoint's purchase of such natural gas at above market prices, the non-CenterPoint defendants, including the above-listed Kinder Morgan entities, sell natural gas to CenterPoint's non-regulated affiliates at prices substantially below market, which in turn sells such natural gas to commercial and industrial consumers and gas marketers at market price. The complaint purports to assert claims for fraud, unlawful enrichment and civil conspiracy against all of the defendants, and seeks relief in the form of actual, exemplary and punitive damages, interest, and attorneys' fees. The parties have recently concluded jurisdictional discovery and various defendants have filed motions arguing that the Arkansas courts lack personal jurisdiction over them. The Court denied these motions. Based on the information available to date and our preliminary investigation, the Kinder Morgan defendants believe that the claims against them are without merit and intend to defend against them vigorously.

Cannon Interests-Houston v. Kinder Morgan Texas Pipeline, L.P., No. 2005-36174 (333rd Judicial District, Harris County, Texas).

On June 6, 2005, after unsuccessful mediation, Cannon Interests sued Kinder Morgan Texas Pipeline, L.P., referred to in this report as KMTP, and alleged breach of contract for the purchase of natural gas storage capacity and for failure to pay under a profit-sharing arrangement. KMTP counterclaimed that Cannon Interests failed to provide it with five billion cubic feet of winter storage capacity in breach of the contract. The plaintiff was claiming approximately $13 million in damages. In May 2006, the parties entered into a confidential settlement that resolved all claims in this matter. The case has been dismissed.

Federal Investigation at Cora and Grand Rivers Coal Facilities

On June 22, 2005, Kinder Morgan Energy Partners announced that the Federal Bureau of Investigation is conducting an investigation related to coal terminal facilities of its subsidiaries located in Rockwood, Illinois and Grand Rivers, Kentucky. The investigation involves certain coal sales from their Cora, Illinois and Grand Rivers, Kentucky coal terminals that occurred from 1997 through 2001. During this time period, the subsidiaries sold excess coal from these two terminals for their own account, generating less than $15 million in total net sales. Excess coal is the weight gain that results from moisture absorption into existing coal during transit or storage and from scale inaccuracies, which are typical in the industry. During the years 1997 through 1999, the subsidiaries collected, and, from 1997 through 2001, the subsidiaries subsequently sold, excess coal for their own account, as they believed they were entitled to do under then-existing customer contracts.

Kinder Morgan Energy Partners has conducted an internal investigation of the allegations and discovered no evidence of wrongdoing or improper activities at these two terminals. Furthermore, it has contacted customers of these terminals during the applicable time period and has offered to share information with them regarding the excess coal sales. Over the five-year period from 1997 to 2001, the subsidiaries moved almost 75 million tons of coal through these terminals, of which less than 1.4 million tons were sold for their own account (including both excess coal and coal purchased on the open market). They have not added to their inventory of excess coal since 1999 and they have not sold coal for their own account since 2001, except for minor amounts of scrap coal. In September 2005 and subsequent thereto, it responded to a subpoena in this matter by producing a large volume of documents, which, we understand, are being reviewed by the FBI and auditors from the Tennessee Valley Authority, which is a customer of the Cora and Grand Rivers terminals. We believe that the federal authorities are also investigating coal inventory practices at one or more of our other terminals. While we have no indication of the direction of this additional investigation, our records do not reflect any sales of excess coal from our other terminals, and we are not aware of any wrongdoing or improper activities at our terminals. Kinder Morgan Energy Partners is cooperating fully with federal law enforcement authorities in this investigation, and expects several of its officers and employees to be interviewed formally by federal authorities. We do not believe there is any basis for criminal charges, and we are engaged in discussions to resolve any possible criminal charges. We do not expect that the resolution of the investigation will have a material adverse impact on our business, financial position, results of operations or cash flows.

Queen City Railcar Litigation

Claims asserted by residents and businesses. On August 28, 2005, a railcar containing the chemical styrene began leaking styrene gas in Cincinnati, Ohio while en route to Kinder Morgan Energy Partners' Queen City Terminal. The railcar was sent by the Westlake Chemical Corporation from Louisiana, transported by Indiana & Ohio Railway, and consigned to Westlake at its dedicated storage tank at Queen City Terminals, Inc., a subsidiary of Kinder Morgan Bulk Terminals, Inc. The railcar leak resulted in the evacuation of many residents and the alleged temporary closure of several businesses in the Cincinnati area. Within three weeks of the incident, seven separate class action complaints were filed in the Hamilton County Court of Common Pleas, including case numbers: A0507115, A0507120, A0507121, A0507149, A0507322, A0507332, and A0507913.

On September 28, 2005, the court consolidated the complaints under consolidated case number A0507913. Concurrently, thirteen designated class representatives filed a Master Class Action Complaint against Westlake Chemical Corporation, Indiana and Ohio Railway Corporation, Queen City Terminals, Inc., Kinder Morgan Liquids Terminals, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan Energy Partners, L.P. (collectively, referred to in this report as the defendants), in the Hamilton County Court of Common Pleas, case number A0507105. The complaint alleges negligence, absolute nuisance, nuisance, trespass, negligence per se, and strict liability against all defendants stemming from the styrene leak. The complaint seeks compensatory damages in excess of $25,000, punitive damages, pre and post-judgment interest, and attorney fees. The claims against the Indiana and Ohio Railway and Westlake are based generally on an alleged failure to deliver the railcar in a timely manner, which allegedly caused the styrene to become unstable and leak from the railcar. The plaintiffs allege that the Kinder Morgan entities named as defendants in the case had a legal duty to monitor the movement of the railcar en route to the Queen City Terminal and guarantee its timely arrival in a safe and stable condition.

On October 28, 2005, the Kinder Morgan entities named as defendants in the case filed an answer denying the material allegations of the complaint. On December 1, 2005, the plaintiffs filed a motion for class certification. On December 12, 2005, the Kinder Morgan entities named as defendants in the case filed a motion for an extension of time to respond to plaintiffs' motion for class certification in order to conduct discovery regarding class certification. On February 10, 2006, the court granted the defendants' motion for additional time to conduct class discovery.

In June 2006, the parties reached an agreement to partially settle the class action suit. On June 29, 2006, the plaintiffs filed an unopposed motion for conditional certification of a settlement class. The settlement provides for a fund of $2.0 million to distribute to residents within the evacuation zone ("Zone 1") and residents immediately adjacent to the evacuation zone ("Zone 2"). Persons in Zones 1 and 2 reside within approximately one mile from the site of the incident. Kinder Morgan Energy Partners agreed to participate in and fund a minor percentage of the settlement. A fairness hearing occurred on August 18, 2006 for the purpose of establishing final approval of the partial settlement. The court approved the settlement, entered final judgment and certified a settlement class for Zones 1 and 2.

One member of the Zone 1 and 2 settlement class, the Estate of George W. Dameron, opted out of the settlement, and the Administratrix of the Dameron Estate filed a wrongful death lawsuit on November 15, 2006 in the Hamilton County Court of Common Pleas, Case No. A0609990. The complaint alleges that styrene exposure caused the death of Mr. Dameron. Kinder Morgan Energy Partners is not a named defendant in such lawsuit, but it is likely that Kinder Morgan Energy Partners will be joined as a defendant, in which case Kinder Morgan Energy Partners intends on vigorously defending against the estate's claim.

Certain claims by other residents and businesses remain pending. Specifically, the Zone 1 and 2 settlement and final judgment does not apply to purported class action claims by residents in outlying geographic zones more than one mile from the site of the incident. Settlement discussions are proceeding with such residents in outlying geographic zones. In addition, the non-Kinder Morgan defendants have agreed to settle remaining claims asserted by businesses and will obtain a release of such claims favoring all defendants, including Kinder Morgan Energy Partners and its affiliates, subject to the retention by all defendants of their claims against each other for contribution and indemnity. Kinder Morgan Energy Partners expects that a claim will be asserted by other defendants against Kinder Morgan Energy Partners seeking contribution or indemnity for any settlements funded exclusively by other defendants, and Kinder Morgan Energy Partners expects to vigorously defend against any such claims.

Claims asserted by the city of Cincinnati. On September 6, 2005 and before the procedural developments in the case discussed above, the city of Cincinnati filed a complaint on behalf of itself and in *parens patriae* against Westlake, Indiana and Ohio Railway, Kinder Morgan Liquids Terminals, LLC, Queen City Terminals, Inc. and Kinder Morgan G.P., Inc. in the Court of Common Pleas, Hamilton County, Ohio, case number A0507323. Plaintiff's complaint arose out of the same railcar incident discussed immediately above. The plaintiff's complaint alleges public nuisance, negligence, strict liability, and trespass. The complaint seeks compensatory damages in excess of $25,000, punitive damages, pre and post-judgment interest, and attorney fees. On September 28, 2005, the Kinder Morgan defendants filed a motion to dismiss the *parens patriae* claim. On December 15, 2005, the Kinder Morgan defendants filed a motion for summary judgment seeking dismissal of the remaining aspects of the city's complaint. Oral argument on the Kinder Morgan defendants' motions was scheduled for December 8, 2006. At the hearing, the court referred the parties to mediation. The parties agreed to stay discovery until after the mediation, if necessary. No trial date has been established.

Leukemia Cluster Litigation

Kinder Morgan Energy Partners is a party to two wrongful death lawsuits in Nevada that allege that the plaintiffs have developed leukemia as a result of exposure to harmful substances. Based on the information available to date, Kinder Morgan Energy Partners' own preliminary investigation, and the positive results of investigations conducted by State and Federal agencies, Kinder Morgan Energy Partners believes that the claims against it in these matters are without merit and intends to defend against them vigorously. The following is a summary of these cases.

Richard Jernee, et al. v. Kinder Morgan Energy Partners, et al., No. CV03-03482 (Second Judicial District Court, State of Nevada, County of Washoe) ("Jernee").

On May 30, 2003, plaintiffs, individually and on behalf of Adam Jernee, filed a civil action in the Nevada State trial court against Kinder Morgan Energy Partners and several Kinder Morgan related entities and individuals and additional unrelated defendants. Plaintiffs in the Jernee matter claim that defendants negligently and intentionally failed to inspect, repair and replace unidentified segments of their pipeline and facilities, allowing "harmful substances and emissions and gases" to damage "the environment and health of human beings." Plaintiffs claim that "Adam Jernee's death was caused by leukemia that, in turn, is believed to be due to exposure to industrial chemicals and toxins." Plaintiffs purport to assert claims for wrongful death, premises liability, negligence, negligence per se, intentional infliction of emotional distress, negligent infliction of emotional distress, assault and battery, nuisance, fraud, strict liability (ultra hazardous acts), and aiding and abetting, and seek unspecified special, general and punitive damages. The Jernee case has been consolidated for pretrial purposes with the Sands case (see below). Plaintiffs have filed a third amended complaint and all defendants filed motions to dismiss all causes of action excluding plaintiffs' cause of action for negligence. Defendants also filed motions to strike portions of the complaint. By order dated May 5, 2006, the court granted defendants' motions to dismiss as to the counts purporting to assert claims for fraud, but denied defendants' motions to dismiss as to the remaining counts, as well as defendants' motions to strike. Defendant Kennametal, Inc. has filed a third-party complaint naming the United States and the United States Navy (the "United States") as additional defendants. In response, the United States removed the case to the United States District Court for the District of Nevada and filed a motion to dismiss the third-party complaint, which motion is currently pending. Plaintiff has also filed a motion to dismiss the United States and/or to remand the case back to state court. Briefing on these motions has been completed and the motions remain pending.

Floyd Sands, et al. v. Kinder Morgan Energy Partners, et al., No. CV03-05326 (Second Judicial District Court, State of Nevada, County of Washoe) ("Sands").

On August 28, 2003, a separate group of plaintiffs, represented by the counsel for the plaintiffs in the Jernee matter, individually and on behalf of Stephanie Suzanne Sands, filed a civil action in the Nevada State trial court against Kinder Morgan Energy Partners and several Kinder Morgan related entities and individuals and additional unrelated defendants. The Kinder Morgan defendants were served with the complaint on January 10, 2004. Plaintiffs in the Sands matter claim that defendants negligently and intentionally failed to inspect, repair and replace unidentified segments of their pipeline and facilities, allowing "harmful substances and emissions and gases" to damage "the environment and health of human beings." Plaintiffs claim that Stephanie Suzanne Sands' death was caused by leukemia that, in turn, is believed to be due to exposure to industrial chemicals and toxins. Plaintiffs purport to assert claims for wrongful death, premises liability, negligence, negligence per se, intentional infliction of emotional distress, negligent infliction of emotional distress, assault and battery, nuisance, fraud, strict liability (ultra hazardous acts), and aiding and abetting, and seek unspecified special, general and punitive damages. The Sands case has been consolidated for pretrial purposes with the Jernee case (see above). Plaintiffs have filed a third amended complaint and all defendants filed motions to dismiss all causes of action excluding plaintiffs' cause of action for negligence. Defendants also filed motions to strike portions of the complaint. By order dated May 5, 2006, the court granted defendants' motions to dismiss as to the counts purporting to assert claims for fraud, but denied defendants' motions to dismiss as to the remaining counts, as well as defendants' motions to strike. Defendant Kennametal, Inc. has filed a third-party complaint naming the United States and the United States Navy (the "United States") as additional defendants. In response, the United States removed the case to the United States District Court for the District of Nevada and filed a motion to dismiss the third-party complaint, which motion is currently pending. Plaintiff has also filed a motion to dismiss the United States and/or to remand the case back to state court. Briefing on these motions has been completed and the motions remain pending.

Pipeline Integrity and Releases

Harrison County Texas Pipeline Rupture

On May 13, 2005, NGPL experienced a rupture on its 36-inch diameter Gulf Coast #3 natural gas pipeline in Harrison County, Texas. The pipeline rupture resulted in an explosion and fire that severely damaged the Harrison County Power Project plant ("HCCP"), an adjacent power plant. In addition, local residents within an approximate one-mile radius were evacuated by local authorities until the site was secured. On October 24, 2006, suit was filed under Cause No. 06-1030 in the 71st Judicial District Court of Harrison County, Texas against NGPL and us by Plaintiffs, Entergy Power Ventures, L.P., Northeast Texas Electric Cooperative, Inc., East Texas Electric Cooperative, Inc. and Arkansas Electric Cooperative Corporation, owners and interest holders in the HCCP. The Plaintiffs allege claims of breach of contract, negligence, gross negligence, and trespass, and are seeking to recover for property damage and for losses due to business interruption. We are working with outside legal counsel and our insurance adjusters to evaluate and adjust this claim as necessary.

Walnut Creek, California Pipeline Rupture

On November 9, 2004, excavation equipment operated by Mountain Cascade, Inc., a third-party contractor on a water main installation project hired by East Bay Municipal Utility District ("EBMUD"), struck and ruptured an underground petroleum pipeline owned and operated by SFPP in Walnut Creek, California. An explosion occurred immediately following the rupture that resulted in five fatalities and several injuries to employees or contractors of Mountain Cascade. The explosion and fire also caused property damage.

On May 5, 2005, the California Division of Occupational Safety and Health ("CalOSHA") issued two civil citations against Kinder Morgan Energy Partners relating to this incident assessing civil fines of $140,000 based upon its alleged failure to mark the location of the pipeline properly prior to the excavation of the site by the contractor. On June 27, 2005, the Office of the California State Fire Marshal, Pipeline Safety Division, referred to in this report as the CSFM, issued a notice of violation against Kinder Morgan Energy Partners which also alleged that it did not properly mark the location of the pipeline in violation of state and federal regulations. The CSFM assessed a proposed civil penalty of $0.5 million. The location of the incident was not SFPP's work site, nor did SFPP have any direct involvement in the water main replacement project. We believe that SFPP acted in accordance with applicable law and regulations, and further that according to California law, excavators, such as the contractor on the project, must take the necessary steps (including excavating with hand tools) to confirm the exact location of a pipeline before using any power operated or power driven excavation equipment. Accordingly, we disagree with certain of the findings of CalOSHA and the CSFM, and SFPP has appealed the civil penalties while, at the same time, continuing to work cooperatively with CalOSHA and the CSFM to resolve these matters.

CalOSHA, with the assistance of the Contra Costa County District Attorney's office, is continuing to investigate the facts and circumstances surrounding the incident for possible criminal violations. Kinder Morgan Energy Partners has been notified by the Contra Costa County District Attorney's office that it intends to pursue criminal charges against it in connection with the Walnut Creek pipeline rupture. We have responded by reiterating our belief that the facts and circumstances do not warrant criminal charges. We are currently engaged in discussions with the Contra Costa County District Attorney's office in an effort to resolve any possible criminal charges. In the event that we are not able to reach a resolution, we anticipate that the Contra Costa County District Attorney will pursue criminal charges, and we intend to defend such charges vigorously.

As a result of the accident, nine separate lawsuits have been filed. Each of these lawsuits is currently coordinated in Contra Costa County Superior Court. There are also several cross- complaints for indemnity between the co-defendants in the coordinated lawsuits. The majority of the cases are personal injury and wrongful death actions. These are: *Knox, et al. v. Mountain Cascade, et al.* (Contra Costa Sup. Ct. Case No. C 05-00281); *Farley v. Mountain Cascade, et al.* (Contra Costa Sup. Ct. Case No. C 05-01573); *Reyes, et al. v. East Bay Municipal Utility District, et al.* (Alameda Sup. Ct. Case No. RG-05-207720); *Arias, et al. v. Kinder Morgan, et al.* (Alameda Sup. Ct. Case No. RG-05-195567); *Angeles, et al. v. Kinder Morgan, et al.* (Alameda Sup. Ct. Case No. RG-05-195680); *Ramos, et al. v. East Bay Municipal Utility District, et al.* (Contra Costa County Superior Court Case No. C05-01840); *Taylor, et al. v. East Bay Municipal Utility District, et al.* (Contra Costa County Superior Court Case No. C05-02306); *Becerra v. Kinder Morgan Energy Partners, L.P., et al.*, (Contra Costa County Superior Court Case No. C05-02451); *Im, et al. v. Kinder Morgan, Inc. et al.* (Contra Costa County Superior Court Case No. C05-02077); *Paasch, et al. v. East Bay Municipal Utility District, et al.* (Contra Costa County Superior Court Case No. C05-01844); *Fuentes et al. v. Kinder Morgan, et al.* (Contra Costa County Superior Court Case No. C05-02286); *Berry et al. v. Kinder Morgan, et al.* (Contra Costa County Superior Court Case No. C06-010524); *Pena et al. v. Kinder Morgan, et al.* (Contra Costa County Superior Court Case No. C06-01051); *Bower et al. v. Kinder Morgan, et al.* (Contra Costa County Superior Court Case No. MSC06-02129 (unserved)); and *Ross et al. v. Kinder Morgan, et al.* (Contra Costa County Superior Court Case No. MSC06-02299 (unserved)). These complaints all allege, among other things, that the Kinder Morgan defendants failed to properly field mark the area where the accident occurred. All of these plaintiffs sought compensatory and punitive damages. These complaints also alleged that the general contractor who struck the pipeline, Mountain Cascade, Inc. ("MCI"), and EBMUD were at fault for negligently failing to locate the pipeline. Some of these complaints also named various engineers on the project for negligently failing to draw up adequate plans indicating the bend in the pipeline. A number of these actions also named Comforce Technical Services as a defendant. Comforce supplied SFPP with temporary employees/independent contractors who performed line marking and inspections of the pipeline on behalf of SFPP. Some of these complaints also named various governmental entities—such as the City of Walnut Creek, Contra Costa County, and the Contra Costa Flood Control and Water Conservation District—as defendants.

Two of the suits are related to alleged damage to a residence near the accident site. These are: *USAA v. East Bay Municipal Utility District, et al.*, (Contra Costa County Superior Court Case No. C05-02128); and *Chabot v. East Bay Municipal Utilities District, et al.*, (Contra Costa Superior Court Case No. C05-02312). The remaining two suits are by MCI and the welding subcontractor, Matamoros. These are: *Matamoros v. Kinder Morgan Energy Partners, L.P., et al.*, (Contra Costa County Superior Court Case No. C05-02349); and *Mountain Cascade, Inc. v. Kinder Morgan Energy Partners, L.P., et al.*, (Contra Costa County Superior Court Case No. C-05-02576). Like the personal injury and wrongful death suits, these lawsuits allege, among other things, that the Kinder Morgan defendants failed to properly mark their pipeline, causing damage to these plaintiffs. The *Chabot* and *USAA* plaintiffs allege property damage, while MCI and Matamoros Welding allege damage to their business as a result of the Kinder Morgan defendants' alleged failures, as well as indemnity and other common law and statutory tort theories of recovery.

Following court ordered mediation, the Kinder Morgan defendants have settled with plaintiffs in all of the wrongful death cases and many of the personal injury and property damages cases. These settlements have either become final by order of the court or are awaiting court approval. The cases which remain unsettled at present are the *Bower, Ross, Chabot, Matamoros, and Mountain Cascade* cases, as well as certain cross-claims for contribution and indemnity by and between various defendants. The parties are currently continuing discovery and court ordered mediation on the remaining cases.

Cordelia, California

On April 28, 2004, SFPP discovered a spill of diesel fuel into a marsh near Cordelia, California from a section of SFPP's 14-inch Concord to Sacramento, California pipeline. Estimates indicated that the size of the spill was approximately 2,450 barrels. Upon discovery of the spill and notification to regulatory agencies, a unified response was implemented with the United States Coast Guard, the California Department of Fish and Game, the Office of Spill Prevention and Response and

SFPP. The damaged section of the pipeline was removed and replaced, and the pipeline resumed operations on May 2, 2004. SFPP has completed recovery of diesel from the marsh and has completed an enhanced biodegradation program for removal of the remaining constituents bound up in soils. The property has been turned back to the owners for its stated purpose. There will be ongoing monitoring under the oversight of the Califor nia Regional Water Quality Control Board until the site conditions demonstrate there are no further actions required.

SFPP is currently in negotiations with the United States Environmental Protection Agency, referred to in this report as the EPA, the United States Fish & Wildlife Service, the California Department of Fish & Game and the San Francisco Regional Water Quality Control Board regarding potential civil penalties and natural resource damages assessments. Since the April 2004 release in the Suisun Marsh area near Cordelia, California, SFPP has cooperated fully with federal and state agencies and has worked diligently to remediate the affected areas. As of December 31, 2005, the remediation was substantially complete.

Oakland, California

In February 2005, Kinder Morgan Energy Partners was contacted by the U.S. Coast Guard regarding a potential release of jet fuel in the Oakland, California area. Its northern California team responded and discovered that one of Kinder Morgan Energy Partners' product pipelines had been damaged by a third party, which resulted in a release of jet fuel which migrated to the storm drain system and the Oakland estuary. Kinder Morgan Energy Partners has coordinated the remediation of the impacts from this release, and is investigating the identity of the third party who damaged the pipeline in order to obtain contribution, indemnity, and to recover any damages associated with the rupture. The EPA, the San Francisco Bay Regional Water Quality Control Board, the California Department of Fish and Game, and possibly the County of Alameda are asserting civil penalty claims with respect to this release. Kinder Morgan Energy Partners is currently in settlement negotiations with these agencies. Kinder Morgan Energy Partners will vigorously contest any unsupported, duplicative or excessive civil penalty claims, but hopes to be able to resolve the demands by each governmental entity through out-of-court settlements.

Donner Summit, California

In April 2005, the SFPP pipeline in Northern California, which transports refined petroleum products to Reno, Nevada, experienced a failure in the line from external damage, resulting in a release of product that affected a limited area adjacent to the pipeline near the summit of Donner Pass. The release was located on land administered by the Forest Service, an agency within the U.S. Department of Agriculture. Initial remediation has been conducted in the immediate vicinity of the pipeline. All agency requirements have been met and the site will be closed upon completion of the remediation. Civil penalty claims on behalf of the EPA, the California Department of Fish and Game, and the Lahontan Regional Water Quality Control Board have been made. SFPP is currently in settlement negotiations with these agencies. SFPP will vigorously contest any unsupported, duplicative or excessive civil penalty claims, but hopes to be able to resolve the demands by each governmental entity through out-of-court settlements.

Baker, California

In November 2004, near Baker, California, the CALNEV Pipeline experienced a failure in its pipeline from external damage, resulting in a release of gasoline that affected approximately two acres of land in the high desert administered by The Bureau of Land Management, an agency within the U.S. Department of the Interior. Remediation has been conducted and continues for product in the soils. All agency requirements have been met and the site will be closed upon completion of the soil remediation. The State of California Department of Fish & Game has alleged a small natural resource damage claim that is currently under review. CALNEV expects to work cooperatively with the Department of Fish & Game to resolve this claim.

Henrico County, Virginia

On April 17, 2006, Plantation Pipe Line Company, which transports refined petroleum products across the southeastern United States and which is 51.17% owned and operated by Kinder Morgan Energy Partners, experienced a pipeline release of turbine fuel from its 12-inch pipeline. The release occurred in a residential ar ea and impacted adjacent homes, yards and common areas, as well as a nearby stream. The released product did not ignite and there were no deaths or injuries. Plantation estimates the amount of product released to be approximately 553 barrels. Immediately following the release, the pipeline was shut down and emergency remediation activities were initiated. Remediation and monitoring activities are ongoing under the supervision of the EPA and the Virginia Department of Environmental Quality, referred to in this report as the VDEQ. In February 2007, the VDEQ proposed a civil penalty of approximately $0.8 million in this matter, and is also seeking reimbursement for oversight costs in amounts less than $0.1 million. Plantation is evaluating the VDEQ's penalty proposal and will engage the VDEQ in settlement discussions.

Repairs to the pipeline were completed on April 19, 2006 with the approval of the United States Department of Transportation, Pipeline and Hazardous Mate rials Safety Administration, referred to in this report as the PHMSA, and pipeline service resumed on April 20, 2006. On April 20, 2006, the PHMSA issued a corrective action order which, among other things, requires that Plantation maintain a 20% reduction in the operating pressure along the pipeline between the Richmond and Newington, Virginia pump stations while the cause is investigated and a remediation plan is proposed and approved by PHMSA. The cause of the release is related to an original pipe manufacturing seam defect.

Dublin, California

In June 2006, near Dublin, California, the SFPP pipeline, which transports refined petroleum products to San Jose, California, experienced a leak, resulting in a release of product that affected a limited area along a recreation path known as the Iron Horse Trail. Product impacts were primarily limited to backfill of utilities crossing the pipeline. The release was located on land administered by Alameda County, California. Remediation and monitoring activities are ongoing under the supervision of The State of California Department of Fish & Game. The cause of the release was outside force damage. SFPP is currently investigating potential recovery against third parties.

Soda Springs, California

In August 2006, the SFPP pipeline, which transports refined petroleum products to Reno, Nevada, experienced a failure near Soda Springs, California, resulting in a release of product that affected a limited area along Interstate Highway 80. Product impacts were primarily limited to soil in an area between the pipeline and Interstate Highway 80. The release was located on land administered by Nevada County, California. Remediation and monitoring activities are ongoing under the supervision of The State of California Department of Fish & Game and Nevada County. The cause of the release is currently under investigation.

Rockies Express Pipeline LLC Wyoming Construction Incident

On November 11, 2006, a bulldozer operated by an employee of Associated Pipeline Contractors, Inc, (a third-party contractor to Rockies Express Pipeline LLC, referred to in this report as REX, for construction of this segment of the new REX pipeline), struck an existing subsurface natural gas pipeline owned by Wyoming Interstate Company and operated by Colorado Interstate Gas Company, both subsidiaries of El Paso Pipeline Group. The Wyoming Interstate Company pipeline was ruptured, resulting in an explosion and fire. The incident occurred in a rural area approximately nine miles southwest of Cheyenne, Wyoming. The incident resulted in one fatality (the operator of the bulldozer) and there were no other reported injuries.

The cause of the incident is under investigation by the PHMSA, as well as the Wyoming Occupational Safety and Health Administration. Kinder Morgan Energy Partners is cooperating with both agencies. Immediately following the incident, REX and El Paso Pipeline Group reached an agreement on a set of additional enhanced safety protocols designed to prevent the reoccurrence of such an incident. Kinder Morgan Energy Partners has been contacted by attorneys representing the estate and the family of the deceased bulldozer operator regarding potential claims related to the incident. Although the internal and external investigations are currently ongoing, based upon presently available information, we believe that REX acted appropriately and in compliance with all applicable laws and regulations.

Charlotte, North Carolina'

On November 27, 2006, the Plantation Pipeline experienced a release of approximately four thousand gallons of gasoline from a Plantation Pipe Line Company block valve on a delivery line into a terminal owned by a third party company. Upon discovery of the release, Plantation immediately locked out the delivery of gasoline through that pipe to prevent further releases. Product had flowed onto the surface and into a nearby stream, which is a tributary of Paw Creek, and resulted in loss of fish and other biota. Product recovery and remediation efforts were implemented immediately, including removal of product from the stream. Remediation efforts are continuing under the direction of the North Carolina Department of Environment and Natural Resources, referred to in this report as the NCDENR, which issued a Notice of Violation and Recommendation of Enforcement against Plantation on January 8, 2007. Plantation continues to cooperate fully with the NCDENR, but does not believe that a penalty is warranted given the quality of Plantation's response efforts. The line was repaired and put back into service within a few days.

Proposed Office of Pipeline Safety Civil Penalty and Compliance Order

On July 15, 2004, the PHMSA issued a proposed civil penalty and proposed compliance order concerning alleged violations of certain federal regulations concerning Kinder Morgan Energy Partners' products pipeline integrity management program. The violations alleged in the proposed order are based upon the results of inspections of Kinder Morgan Energy Partners' integrity management program at its products pipelines facilities in Orange, California and Doraville, Georgia conducted in April and June of 2003, respectively. PHMSA sought to have Kinder Morgan Energy Partners implement a number of changes to its integrity management program and also sought to impose a proposed civil penalty of approximately \$0.3 million. An administrative hearing was held on April 11 and 12, 2005, and a final order was issued on June 26, 2006. Kinder Morgan Energy Partners has already addressed most of the concerns identified by PHMSA and continues to work with them to ensure that its integrity management program satisfies all applicable regulations. However, Kinder Morgan Energy Partners is seeking clarification for portions of this order and has received an extension of time to allow for discussions. Along with the extension, Kinder Morgan Energy Partners reserved its right to seek reconsideration if needed. We have established a reserve for the $0.3 million proposed civil penalty. Subsequent to the 2004 inspection and order, most if not all findings have been addressed. We are currently waiting for the final report from PHMSA's 2006 reinspection of our Integrity Management Plan and we expect positive findings. This matter is not expected to have a material impact on our business, financial position, results of operations or cash flows.

Pipeline and Hazardous Materials Safety Administration Corrective Action Order

On August 26, 2005, Kinder Morgan Energy Partners announced that it had received a corrective action order issued by the PHMSA. The corrective order instructs Kinder Morgan Energy Partners to comprehensively address potential integrity threats along the pipelines that comprise its Pacific operations. The corrective order focused primarily on eight pipeline incidents, seven of which occurred in the State of California. The PHMSA attributed five of the eight incidents to "outside force damage," such as third-party damage caused by an excavator or damage caused during pipeline construction.

Following the issuance of the corrective order, Kinder Morgan Energy Partners engaged in cooperative discussions with the PHMSA and reached an agreement in principle on the terms of a consent agreement with the PHMSA, subject to the PHMSA's obligation to provide notice and an opportunity to comment on the consent agreement to appropriate state officials pursuant to 49 USC Section 60112(c). This comment period closed on March 26, 2006.

On April 10, 2006, Kinder Morgan Energy Partners announced the final consent agreement, which will, among other things, require Kinder Morgan Energy Partners to perform a thorough analysis of recent pipeline incidents, provide for a third-party independent review of its operations and procedural practices, and restructure its internal inspections program. Furthermore, Kinder Morgan Energy Partners has reviewed all of its policies and procedures and is currently implementing various measures to strengthen its integrity management program, including a comprehensive evaluation of internal inspection technologies and other methods to protect its pipelines. Kinder Morgan Energy Partners expects to spend approximately $90 million on pipeline integrity activities for its Pacific operations' pipelines over the next five years. Of that amount, approximately $26 million is related to this consent agreement. Currently, Kinder Morgan Energy Partners has made all submittals required by the agreement schedule and all submittals have been found to be acceptable. We do not expect that Kinder Morgan Energy Partners' compliance with the consent agreement will have a material adverse effect on our business, financial position, results of operations or cash flows.

Maricopa County, Arizona Order of Abatement by Consent

On December 29, 2006, Kinder Morgan Energy Partners received and executed an order of abatement by consent and settlement in the amount of $0.2 million with Maricopa County Air Quality Department relating to several notices of violations associated with its Pacific operations' pipeline terminal in Phoenix, Arizona.

General

Although no assurances can be given, we believe that we have meritorious defenses to all of these actions. Furthermore, to the extent an assessment of the matter is possible, if it is probable that a liability has been incurred and the amount of loss can be reasonably estimated, we believe that we have established an adequate reserve to cover potential liability. We also believe that these matters will not have a material adverse effect on our business, financial position, results of operations or cash flows.

Environmental Matters

Exxon Mobil Corporation v. GATX Corporation, Kinder Morgan Liquids Terminals, Inc. and ST Services, Inc.

On April 23, 2003, Exxon Mobil Corporation filed a complaint in the Superior Court of New Jersey, Gloucester County. Kinder Morgan Energy Partners filed its answer to the complaint on June 27, 2003, in which it denied ExxonMobil's claims and allegations as well as included counterclaims against ExxonMobil. The lawsuit relates to environmental remediation obligations at a Paulsboro, New Jersey liquids terminal owned by ExxonMobil from the mid-1950s through November 1989, by GATX Terminals Corp. from 1989 through September 2000, and owned currently by ST Services, Inc. Prior to selling the terminal to GATX Terminals, ExxonMobil performed the environmental site assessment of the terminal required prior to sale pursuant to state law. During the site assessment, ExxonMobil discovered items that required remediation and the New Jersey Department of Environmental Protection issued an order that required ExxonMobil to perform various remediation activities to remove hydrocarbon contamination at the terminal. ExxonMobil, we understand, is still remediating the site and has not been removed as a responsible party from the state's cleanup order; however, ExxonMobil claims that the remediation continues because of GATX Terminals' storage of a fuel additive, MTBE, at the terminal during GATX Terminals' ownership of the terminal. When GATX Terminals sold the terminal to ST Services, the parties indemnified one another for certain environmental matters. When GATX Terminals was sold to Kinder Morgan Energy Partners, GATX Terminals' indemnification obligations, if any, to ST Services may have passed to Kinder Morgan Energy Partners. Consequently, at issue is any indemnification obligation Kinder Morgan Energy Partners may owe to ST Services for environmental remediation of MTBE at the terminal. The complaint seeks any and all damages related to remediating MTBE at the terminal, and, according to the New Jersey Spill Compensation and Control Act, treble damages may be available for actual dollars incorrectly spent by the successful party in the lawsuit for remediating MTBE at the terminal. The parties have completed limited discovery. In October 2004, the judge assigned to the case dismissed himself from the case based on a conflict, and the new judge has ordered the parties to participate in mandatory mediation. The parties participated in a mediation on November 2, 2005, but no resolution was reached regarding the claims set out in the lawsuit. At this time, the mediation judge is working with a technical consultant and reviewing reports of scientific studies conducted at the site. We anticipate that there will be another mediation session during the second quarter of 2007.

The City of Los Angeles v. Kinder Morgan Energy Partners, L.P.; Kinder Morgan Liquids Terminals LLC; Kinder Morgan Tank Storage Terminals LLC; Continental Oil Company; Chevron Corporation, California Superior Court, County of Los Angeles, Case No. NC041463.

Kinder Morgan Energy Partners and some of its subsidiaries are defendants in a lawsuit filed in 2005 captioned *The City of Los Angeles v. Kinder Morgan Energy Partners, L.P.; Kinder Morgan Liquids Terminals LLC; Kinder Morgan Tank Storage Terminals LLC; Continental Oil Company; Chevron Corporation*, California Superior Court, County of Los Angeles, Case No. NC041463. This suit involves claims for environmental cleanup costs and rent at the former Los Angeles Marine Terminal in the Port of Los Angeles. Plaintiff alleges that terminal cleanup costs could approach $18 million; however, we believe that the cleanup costs should be substantially less, and that cleanup costs must be apportioned among all the parties to the litigation. Plaintiff also alleges that it is owed approximately $2.8 million in past rent and an unspecified amount for future rent; however, we believe that previously paid rents will offset some of the plaintiff's rent claim and that we have certain defenses to the payment of rent allegedly owed. The lawsuit is set for trial in October 2007.

Currently, this lawsuit is still in a preliminary stage of discovery, and the parties to the lawsuit have engaged environmental consultants to investigate environmental conditions at the terminal and to consider remedial options for those conditions. The California Regional Water Quality Control Board is the regulatory agency overseeing the environmental investigation and expected remedial work at the terminal, having issued formal directives to Kinder Morgan Energy Partners, Plaintiff and the other defendants in the lawsuit to investigate terminal contamination and to propose a remedial action plan to address that contamination. We are supporting a lower cost cleanup that will meet state and federal regulatory requirements. We will vigorously defend these matters and believe that the outcome will not have a material adverse effect on us.

Other Environmental

Kinder Morgan Transmix Company has been in discussions with the EPA regarding allegations by the EPA that it violated certain provisions of the Clean Air Act and the Resource Conservation & Recovery Act. Specifically, the EPA claims that Transmix failed to comply with certain sampling protocols at its Indianola, Pennsylvania transmix facility in violation of the Clean Air Act's provisions governing fuel. The EPA further claims that Transmix improperly accepted hazardous waste at its transmix facility in Indianola. Finally, the EPA claims that Transmix failed to obtain batch samples of gasoline produced at its Hartford (Wood River), Illinois facility in 2004. In addition to injunctive relief that would require Transmix to maintain additional oversight of its quality assurance program at all of its transmix facilities, the EPA is seeking monetary penalties of $0.6 million.

We are subject to environmental cleanup and enforcement actions from time to time. In particular, the federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) generally imposes joint and several liability for cleanup and enforcement costs on current or predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct. Our operations are also subject to federal, state and local laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental law and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and carbon dioxide field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities to us.

We are currently involved in several governmental proceedings involving air, water and waste violations issued by various governmental authorities related to compliance with environmental regulations. As we receive notices of non-compliance, we negotiate and settle these matters. We do not believe that these violations will have a material adverse affect on our business.

We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under administrative orders or related state remediation programs issued by various regulatory authorities related to compliance with environmental regulations associated with our assets. We have established a reserve to address the costs associated with the cleanup.

In addition, we are involved with and have been identified as a potentially responsible party in several federal and state superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, natural gas liquids, natural gas and carbon dioxide.

See "—Pipeline Integrity and Ruptures" above for information with respect to the environmental impact of recent ruptures of some of our pipelines.

Although no assurance can be given, we believe that the ultimate resolution of the environmental matters set forth in this note will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, we are not able to reasonably estimate when the eventual settlements of these claims will occur. Many factors may change in the future affecting our reserve estimates, such as regulatory changes, groundwater and land use near our sites, and changes in cleanup technology. At December 31, 2006 and 2005, we accrued environmental reserves of $77.8 million and $16.8 million, respectively.

Assessment of Additional Sales Tax

Terasen Gas received a Notice of Assessment dated July 31, 2006 from the British Columbia Social Service Tax authority for C$37.1 million of additional provincial sales tax and interest on the Southern Crossing Pipeline, which was completed in 2000. We are appealing this assessment and we believe this assessment is without merit and will not have a material adverse impact on our business, financial position, results of operations or cash flows.

Retroactive Quebec Tax Amendments

In June 2006, two Terasen entities received notices of reassessment from Revenue Quebec for a total of C$10.9 million for the 2004 taxation year. These reassessments were made pursuant to new, retroactive legislation passed in Quebec in June 2006 for the express purpose of challenging certain inter-provincial Canadian tax structures. In October, we received assessments totaling C$8.4 million for the 2005 tax year. Terasen has filed Notices of Objection for the 2004 and 2005 reassessments to preserve its legal rights to challenge any assessments/reassessments arising from this retroactive legislation and to vigorously defend against all such assessments/reassessments. The reassessment plus any accrued interest to November 30, 2005 has been accounted for as a purchase price adjustment for the Terasen acquisition and any interest subsequent to the date of the acquisition has been included in interest expense in the accompanying Consolidated Statements of Operations.

Litigation Relating to Proposed Kinder Morgan, Inc. "Going Private" Transaction

On May 28, 2006, Richard D. Kinder, our Chairman and Chief Executive Officer, together with other members of Kinder Morgan, Inc.'s management, co-founder Bill Morgan, current board members Fayez Sarofim and Mike Morgan, and investment partners Goldman Sachs Capital Partners, American International Group, Inc., The Carlyle Group and Riverstone Holdings LLC, submitted a proposal to our Board of Directors to acquire all of our outstanding common stock at a price of $100 per share in cash. On August 28, 2006, Kinder Morgan, Inc. entered into a definitive merger agreement with Knight Holdco LLC and Knight Acquisition Co. to effectuate the transaction at a price of $107.50 per share in cash.

Beginning on May 29, 2006, and in the days following, eight putative Class Action lawsuits were filed in Harris County (Houston), Texas and seven putative Class Action lawsuits were filed in Shawnee County (Topeka), Kansas against, among others, Kinder Morgan, Inc., its Board of Directors, and several corporate officers.

These cases are as follows:

Harris County, Texas

Cause No. 2006-33011; *Mary Crescente v. Kinder Morgan, Inc., Richard D. Kinder, Edward H. Austin, Charles W. Battey, Stewart A. Bliss, Ted A. Gardner, William J. Hybl, Michael C. Morgan, Edward Randall III, Fayez S. Sarofim, H.A. True III, Douglas W.G. Whitehead, and James M. Stanford*; in the 164th Judicial District Court, Harris County, Texas

Cause No. 2006-39364; *CWA/ITU Negotiated Pension Plan, individually and on behalf of others similarly situated v. Kinder Morgan, Inc., Richard D. Kinder, Edward H. Austin, Jr., William J. Hybl, Ted A. Gardner, Charles W. Battery, H.A. True, III, Fayez Sarofim, James M. Stanford, Michael C. Morgan, Stewart A. Bliss, Edward Randall, III, and Douglas W.G. Whitehead*; in the 129th Judicial District Court, Harris County, Texas

Cause No. 2006-33015; *Robert Kemp, on behalf of himself and all other similarly situated v. Richard D. Kinder, Edward H. Austin, Jr., William J. Hybl, Ted A. Gardner, Charles W. Battey, H.A. True, III, Fayez Sarofim, James Stanford, Michael C. Morgan, Stewart A. Bliss, Edward Randall III, Douglas W. G. Whitehead, Kinder Morgan, Inc., GS Capital Partners V Fund, L.P., AIG Global Asset Management Holdings Corp., Carlyle Partners IV, L.P., and Carlyle/Riverstone Energy Partners III, L.P.*; in the 113th Judicial District Court, Harris County, Texas

Cause No. 2006-34594; *Dean Drulias v. Kinder Morgan, Inc., Richard D. Kinder, Edward H. Austin, Jr., William J. Hybl, Ted A. Gardner, Charles W. Battey, H.A. True III, Fayez S. Sarofim, James Stanford, Michael C. Morgan, Stewart A. Bliss, Edward Randall III, Douglas W.G. Whitehead, Goldman Sachs, American International Group, Inc., the Carlyle Group, and Riverstone Holdings, LLC*; in the 333rd Judicial District Court, Harris County, Texas

Cause No. 2006-40027; *J. Robert Wilson, On Behalf of Himself and All Others Similarly Situated v. Kinder Morgan, Inc., Richard D. Kinder, Michael C. Morgan, Fayez Sarofim, Edward H. Austin, Jr., William J. Hybl, Ted A. Gardner, Charles W. Battey, H.A. True, III, James M. Stanford, Stewart A. Bliss, Edward Randall, III, Douglas W.G. Whitehead, Bill Morgan, Goldman Sachs Capital Partners, American International Group, Inc., The Carlyle Group, Riverstone Holdings, L.L.C., C. Park Shaper, Steven J. Kean, Scott E. Parker, and Tim Bradley*; in the 270th Judicial District Court, Harris County, Texas

Cause No. 2006-33042; *Sandra Donnelly, On Behalf of Herself and All Others Similarly Situated v. Kinder Morgan, Inc., Richard D. Kinder, Michael C. Morgan, Fayez S. Sarofim, Edward H. Austin, Jr., William J. Hybl, Ted A. Gardner, Charles W. Battey, H.A. True III, James M. Stanford, Stewart A. Bliss, Edward Randall III, and Douglas W.G. Whitehead*; in the 61st Judicial District Court, Harris County, Texas

Cause No. 2006-34520; *David Zeitz, On Behalf of Himself and All Others Similarly Situated v. Richard D. Kinder*; in the 234th Judicial District Court, Harris County, Texas

Cause No. 2006-36184; *Robert L. Dunn, Trustee for the Dunn Marital Trust, and the Police & Fire Retirement System of the City of Detroit v. Richard D. Kinder, Edward H. Austin, Jr., William J. Hybl, Ted A. Gardner, Charles W. Battey, H.A. True, III, Fayez Sarofim, James M. Stanford, Michael C. Morgan, Stewart A. Bliss, Edward Randall III, and Douglas W.G. Whitehead*; in the 127th Judicial District Court, Harris County, Texas

By order of the Court dated June 26, 2006, each of the above-listed cases have been consolidated into the *Crescente v. Kinder Morgan, Inc. et al* case; in the 164th Judicial District Court, Harris County, Texas, which challenges the proposed transaction as inadequate and unfair to Kinder Morgan's public stockholders. Seven of the eight original petitions consolidated into this lawsuit raised virtually identical allegations. One of the eight original petitions (*Zeitz*) challenges the proposal as unfair to holders of the common units of Kinder Morgan Energy Partners and/or listed shares of Kinder Morgan Management. On September 8, 2006, interim class counsel filed their Consolidated Petition for Breach of Fiduciary Duty and Aiding and Abetting in which they alleged that Kinder Morgan's board of directors and certain members of senior management breached their fiduciary duties and the Sponsor Investors aided and abetted the alleged breaches of fiduciary duty in entering into the merger agreement. They seek, among other things, to enjoin the merger, rescission of the merger agreement, disgorgement of any improper profits received by the defendants, and attorneys' fees. Defendants filed Answers to the Consolidated Petition on October 9, 2006, denying the plaintiffs' substantive allegations and denying that the plaintiffs are entitled to relief.

Shawnee County, Kansas Cases

Cause No. 06C 801; *Michael Morter v. Richard D. Kinder, Edward H. Austin, Jr., Charles W. Battey, Stewart A. Bliss, Ted A. Gardner, William J. Hybl, Michael C. Morgan, Edward Randall, III, Fayez S. Sarofim, H.A. True, III, and Kinder Morgan, Inc.*; in the District Court of Shawnee County, Kansas, Division 12

Cause No. 06C 841; *Teamsters Joint Counsel No. 53 Pension Fund v. Richard D. Kinder, Edward H. Austin, Charles W. Battey, Stewart A. Bliss, Ted A. Gardner, William J. Hybl, Michael C. Morgan, Edward Randall, III, Fayez S. Sarofim, H.A. True, III, and Kinder Morgan, Inc.*; in the District Court of Shawnee County, Kansas, Division 12

Cause No. 06C 813; *Ronald Hodge, Individually And On Behalf Of All Others Similarly Situated v. Kinder Morgan, Inc., Richard D. Kinder, Edward H. Austin, Jr., William J. Hybl, Ted A. Gardner, Charles W. Battery, H.A. True III, Fayez S. Sarofim, James M. Stanford, Michael C. Morgan, Stewart A. Bliss, Edward Randall, III, and Douglas W.G. Whitehead*; in the District Court of Shawnee County, Kansas, Division 6

Cause No. 06C-864; *Robert Cohen, Individually And On Behalf Of All Others Similarly Situated v. Kinder Morgan, Inc., Richard D. Kinder, Edward H. Austin, Jr., William J. Hybl, Ted A. Gardner, Charles W. Battery, H.A. True, III, Fayez Sarofim, James M. Stanford, Michael C. Morgan, Stewart A. Bliss, Edward Randall, III, and Douglas W.G. Whitehead*; in the District Court of Shawnee County, Kansas, Division 6

Cause No. 06C-853; *Robert P. Land, individually, and on behalf of all others similarly situated v. Edward H. Austin, Jr., Charles W. Battey, Stewart A. Bliss, Ted A. Gardner, William J. Hybl, Edward Randall, III, James M. Stanford, Fayez Sarofim, H.A. True, III, Douglas W.G. Whitehead, Richard D. Kinder, Michael C. Morgan, AIG Global Asset Management Holdings Corp., GS Capital Partners V Fund, LP, The Carlyle Group LP, Riverstone Holdings LLC, Bill Morgan and Kinder Morgan, Inc*.; in the District Court of Shawnee County, Kansas, Division 6

Cause No. 06C-854; *Dr. Douglas Geiger, individually, and on behalf of all others similarly situated v. Edward H. Austin, Jr., Charles W. Battey, Stewart A. Bliss, Ted A. Gardner, William J. Hybl, Edward Randall, III, James M. Stanford, Fayez Sarofim, H.A. True, III, Douglas W.G. Whitehead, Richard D. Kinder, Michael C. Morgan, AIG Global Asset Management Holding Corp., GS Capital Partners V Fund, LP, The Carlyle Group LP, Riverstone Holdings LLC, Bill Morgan and Kinder Morgan, Inc*.; in the District Court of Shawnee County, Kansas, Division 6

Cause No. 06C-837; *John Bolton, On Behalf of Himself and All Others Similarly Situated v. Kinder Morgan, Inc., Richard D. Kinder, Michael C. Morgan, Fayez Sarofim, Edward H. Austin, Jr., William J. Hybl, Ted A. Gardner, Charles W. Battey, H.A. True, III, James M. Stanford, Stewart A. Bliss, Edward Randall, III, Douglas W.G. Whitehead, William V. Morgan, Goldman Sachs Capital Partners, American International Group, Inc., The Carlyle Group, Riverstone Holdings LLC, C. Park Shaper, Steven J. Kean, Scott E. Parker and Tim Bradley*; in the District Court of Shawnee County, Kansas, Division 6

By order of the Court dated June 26, 2006, each of the above-listed Kansas cases have been consolidated into the Consol. Case No. 06 C 801; *In Re Kinder Morgan, Inc. Shareholder Litigation*; in the District Court of Shawnee County, Kansas, Division 12. On August 1, 2006, the Court selected lead plaintiffs' counsel in the Kansas State Court proceedings. On August 28, 2006, the plaintiffs filed their Consolidated and Amended Class Action Petition in which they alleged that Kinder Morgan's board of directors and certain members of senior management breached their fiduciary duties and the Sponsor Investors aided and abetted the alleged breaches of fiduciary duty in entering into the merger agreement. They seek, among other things, to enjoin the stockholder vote on the merger agreement and any action taken to effect the acquisition of Kinder Morgan and its assets by the buyout group, damages, disgorgement of any improper profits received by the defendants, and attorney's fees.

On October 12, 2006, the District Court of Shawnee County, Kansas entered a Memorandum Decision and Order in which it ordered the parties in both the *Crescente v. Kinder Morgan, Inc. et al* case pending in Harris County Texas and the *In Re Kinder Morgan, Inc. Shareholder Litigation* case pending in Shawnee County Kansas to confer and to submit to the court recommendations for the "appointment of a Special Master or a Panel of Special Masters to control all of the pretrial proceedings in both the Kansas and Texas Class Actions arising out of the proposed private offer to purchase the stock of the public shareholders of Kinder Morgan, Inc."

By Order dated November 21, 2006, the Kansas District Court appointed the Honorable Joseph T. Walsh to serve as Special Master for *In Re Kinder Morgan, Inc. Shareholder Litigation* case pending in Kansas. By Order dated December 6, 2006, the Texas District Court also appointed the Honorable Joseph T. Walsh to serve as Special Master in the *Crescente v. Kinder Morgan, Inc. et al.* case pending in Texas for the purposes of considering any applications for pretrial temporary injunctive relief. On November 21, 2006, the plaintiffs in *In Re Kinder Morgan, Inc. Shareholder Litigation* filed a Third Amended Class Action Petition with Special Master Walsh. This Petition was later filed under seal with the Kansas District Court on December 27, 2006. Defendants' answer to the Third Amended Class Action Petition is due on March 19, 2007.

Following extensive expedited discovery, the Plaintiffs in both consolidated actions filed an application for a preliminary injunction to prevent the holding of a special meeting of shareholders for the purposes of voting on the proposed merger, which was scheduled for December 19, 2006. The application was briefed by the parties between December 4 – December 13, 2006, and oral argument was heard by Special Master Walsh on December 14, 2006.

On December 18, 2006, Special Master Walsh issued a Report and Recommendation concluding, among other things, that "plaintiffs have failed to demonstrate the probability of ultimate success on the merits of their claims in this joint litigation." Accordingly, the Special Master concluded that the plaintiffs were "not entitled to injunctive relief to prevent the holding of the special meeting of KMI shareholders scheduled for December 19, 2006."

In addition to the above-described consolidated putative Class Action cases, Kinder Morgan, Inc. is aware of two additional lawsuits that challenge either the proposal or the merger agreement.

On July 25, 2006 a civil action entitled *David Dicrease, individually and on behalf of all others similarly situated v. Joseph Listengart, Edward H. Austin, Jr., Charles W. Battey, Stewart A. Bliss, Ted A. Gardner, William J. Hybl, Michael C. Morgan, Edward Randall, III, Fayez Sarofim, James M. Stanford, H.A. True, III, Douglas W.G. Whitehead, Richard D. Kinder, Kinder Morgan, Inc., Kinder Morgan Fiduciary Committee, John Does 1-30*; Case 4:06-cv-02447, was filed in the United States District Court for the Southern District of Texas. This suit purports to be brought on behalf of the Kinder Morgan, Inc. Savings Plan (the "Plan") and a class comprised of all participants and beneficiaries of the Plan, for alleged breaches of fiduciary duties allegedly owed to the Plan and its participants by the defendants, in violation of the Employee Retirement

Income Security Act ("ERISA"). More specifically, the suit asserts that defendants failed to prudently manage the Plan's assets (Count I); failed to appropriately monitor the Fiduciary Committee and provide it with accurate information (Count II); failed to provide complete and accurate information to the Plan's participants and beneficiaries (Count III); failed to avoid conflicts of interest (Count IV) and violated ERISA by engaging in a prohibited transaction (Count V). The relief requested seeks to enjoin the proposed transaction, damages allegedly incurred by the Plan and the participants, recovery of any "unjust enrichment" obtained by the defendants, and attorneys' fees and costs.

On January 8, 2007, the United States District Court granted plaintiffs' motion to dismiss the Dicrease case without prejudice, and the case was terminated on January 8, 2007.

On August 24, 2006, a civil action entitled *City of Inkster Policeman and Fireman Retirement System, Derivatively on Behalf of Kinder Morgan, Inc., Plaintiffs v. Richard D. Kinder, Michael C. Morgan, William v. Morgan, Fayez Sarofim, Edward H. Austin, Jr., William J. Hybl, Ted A. Gardner, Charles W. Battey, H.A. True, III, James M. Stanford, Stewart A. Bliss, Edward Randall, III, Douglas W.G. Whitehead, Goldman Sachs Capital Partners, American International Group, Inc., The Carlyle Group, Riverstone Holdings LLC, C. Park Shaper, Steven J. Kean, Scott E. Parker and R. Tim Bradley, Defendants and Kinder Morgan, Inc., Nominal Defendant;* Case 2006-52653, was filed in the 270th Judicial District Court, Harris County, Texas. This putative derivative lawsuit was brought against certain of Kinder Morgan's senior officers and directors, alleging that the proposal constituted a breach of fiduciary duties owed to Kinder Morgan, Inc. Plaintiff also contends that the Sponsor Investors aided and abetted the alleged breaches of fiduciary duty. Plaintiff seeks, among other things, to enjoin the defendants from consummating the proposal, a declaration that the proposal is unlawful and unenforceable, the imposition of a constructive trust upon any benefits improperly received by the defendants, and attorney's fees. Defendants filed Special Exceptions to the Complaint which sought to have the Complaint dismissed. By agreement dated November 16, 2006 the parties agreed, among other things, to postpone the hearing on Defendants' Special Exceptions, to stay discovery in the Inkster matter, and to provide plaintiff with access to the discovery produced in the *Crescente v. Kinder Morgan, Inc. et al.* case.

Defendants believe that the claims asserted in the lawsuits are legally and factually without merit and intend to vigorously defend against them.

We are a defendant in various lawsuits arising from the day-to-day operations of our businesses. Although no assurance can be given, we believe, based on our experiences to date, that the ultimate resolution of such items will not have a material adverse impact on our business, financial position, results of operations or cash flows.

20. Recent Accounting Pronouncements

On September 15, 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This Statement defines fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. It addresses how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under generally accepted accounting principles and, as a result, there is now a common definition of fair value to be used throughout generally accepted accounting principles.

This Statement applies under other accounting pronouncements that require or permit fair value measurements, the Board having previously concluded in those accounting pronouncements that fair value is the relevant measurement attribute. Accordingly, this Statement does not require any new fair value measurements; however, for some entities the application of this Statement will change current practice. The changes to current practice resulting from the application of this Statement relate to the definition of fair value, the methods used to measure fair value, and the expanded disclosures about fair value measurements.

This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007 (January 1, 2008 for us), and interim periods within those fiscal years. This Statement is to be applied prospectively as of the beginning of the fiscal year in which this Statement is initially applied, with certain exceptions. The disclosure requirements of this Statement are to be applied in the first interim period of the fiscal year in which this Statement is initially applied. We are currently reviewing the effects of this Statement.

On September 29, 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statement Nos. 87, 88, 106 and 132(R).* This Statement requires an employer to:

- recognize the overfunded or underfunded status of a defined benefit pension plan or postretirement benefit plan (other than a multiemployer plan) as an asset or liability in its statement of financial position;
- measure a plan's assets and its obligations that determine its funded status as of the end of the employer's fiscal year (with limited exceptions), and to disclose in the notes to financial statements additional information about certain

effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition assets or obligations; and

- recognize changes in the funded status of a plan in the year in which the changes occur through comprehensive income.

Past accounting standards only required an employer to disclose the complete funded status of its plans in the notes to the financial statements. Recognizing the funded status of a company's benefit plans as a net liability or asset on its balance sheet will require an offsetting adjustment to "Accumulated other comprehensive income/loss" in shareholders' equity. SFAS No. 158 does not change how pensions and other postretirement benefits are accounted for and reported in the income statement—companies will continue to follow the existing guidance in previous accounting standards. Accordingly, the amounts to be recognized in "Accumulated other comprehensive income/loss" representing unrecognized gains/losses, prior service costs/credits, and transition assets/obligations will continue to be amortized under the existing guidance. Those amortized amounts will continue to be reported as net periodic benefit cost in the income statement. Prior to SFAS No. 158, those unrecognized amounts were only disclosed in the notes to the financial statements.

According to the provisions of this Statement, an employer with publicly traded equity securities is required to initially recognize the funded status of a defined benefit pension plan or postretirement benefit plan and to provide the required disclosures as of the end of the fiscal year ending after December 15, 2006 (December 31, 2006 for us). In the year that the recognition provisions of this Statement are initially applied, an employer is required to disclose, in the notes to the annual financial statements, the incremental effect of applying this Statement on individual line items in the year-end statement of financial position. The requirement to measure plan assets and benefit obligations as of the date of the employer's fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008 (December 31, 2008 for us). In the year that the measurement date provisions of this Statement are initially applied, a business entity is required to disclose the separate adjustments of retained earnings and "Accumulated other comprehensive income/loss" from applying this Statement. While earlier application of the recognition of measurement date provisions is allowed, we have opted not to adopt this part of the Statement early.

We will apply the guidance of SFAS No. 158 prospectively; retrospective application of this Statement is not permitted. We are currently reviewing the effects of this Statement, but we do not expect the adoption of this Statement to have a material effect on our statement of financial position as of December 31, 2006.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") No. 108. This Bulletin requires a "dual approach" for quantifications of errors using both a method that focuses on the income statement impact, including the cumulative effect of prior years' misstatements, and a method that focuses on the period-end balance sheet. For us, SAB No. 108 was effective January 1, 2007. The adoption of this Bulletin did not have a material impact on our consolidated financial statements, and we will apply this guidance prospectively.

In June 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109*. This Interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes*. This Interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. It also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. This Interpretation was effective for fiscal years beginning after December 15, 2006 (January 1, 2007 for us). We do not expect the adoption of this Interpretation to have a material impact on our consolidated financial statements.

In June 2006, the FASB ratified the consensuses reached by the Emerging Issues Task Force on EITF 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That is, Gross versus Net Presentation)*. According to the provisions of EITF 06-3:

- taxes assessed by a governmental authority that are directly imposed on a revenue-producing transaction between a seller and a customer may include, but are not limited to, sales, use, value added, and some excise taxes; and

- that the presentation of such taxes on either a gross (included in revenues and costs) or a net (excluded from revenues) basis is an accounting policy decision that should be disclosed pursuant to Accounting Principles Board Opinion No. 22 (as amended), *Disclosure of Accounting Policies*. In addition, for any such taxes that are reported on a gross basis, a company should disclose the amounts of those taxes in interim and annual financial statements for each period for which an income statement is presented if those amounts are significant. The disclosure of those taxes can be done on an aggregate basis.

EITF 06-3 should be applied to financial reports for interim and annual reporting periods beginning after December 15, 2006 (January 1, 2007 for us). Because the provisions of EITF 06-3 require only the presentation of additional disclosures, we do not expect the adoption of EITF 06-3 to have an effect on our consolidated financial statements.

On February 15, 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This Statement provides companies with an option to report selected financial assets and liabilities at fair value. The Statement's objective is to reduce both complexity in accounting for financial instruments and the volatility in earnings caused by measuring related assets and liabilities differently. The Statement also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities.

SFAS No. 159 requires companies to provide additional information that will help investors and other users of financial statements to more easily understand the effect of the company's choice to use fair value on its earnings. It also requires entities to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. The Statement does not eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements included in SFAS No. 157, discussed above, and SFAS No. 107 *Disclosures about Fair Value of Financial Instruments*.

This Statement is effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007 (January 1, 2008 for us). Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity makes that choice in the first 120 days of that fiscal year and also elects to apply the provisions of SFAS No. 157. We are currently reviewing the effects of this Statement.

21. Subsequent Events

On February 26, 2007, we entered into a definitive agreement to sell Terasen Inc. to Fortis Inc. (TSX: FTS), a Canada-based company with investments in regulated distribution utilities, for approximately $3.2 billion (C$3.7 billion) including cash and assumed debt. Terasen Inc.'s principal assets include Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. The transaction is subject to certain closing conditions and regulatory approvals and is expected to close in mid 2007. This sale does not include assets of Kinder Morgan Canada.

On February 21, 2007, we terminated $250 million of our interest rate swap agreements associated with our 7.25% debentures due 2028 and received $19.1 million in cash. This amount will be amortized to interest expense over the period the 7.25% debentures are outstanding.

On January 30, 2007, Kinder Morgan Energy Partners completed a public offering of senior notes. Kinder Morgan Energy Partners issued a total of $1.0 billion in principal amount of senior notes, consisting of $600 million of 6.00% notes due February 1, 2017 and $400 million of 6.50% notes due February 1, 2037. Kinder Morgan Energy Partners received proceeds from the issuance of the notes, after underwriting discounts and commissions, of approximately $992.8 million, and used the proceeds to reduce the borrowings under its commercial paper program.

On January 23, 2007, Terasen Pipelines (Corridor) Inc. increased its credit facility from C$225 million to C$375 million and extended this facility and the associated C$20 million demand facility, as permitted under these facilities, for an additional 364 days.

SELECTED QUARTERLY FINANCIAL DATA
KINDER MORGAN, INC. AND SUBSIDIARIES
Quarterly Operating Results for 2006

	Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(In millions except per share amounts) (Unaudited)			
Operating Revenues	$ 3,293.3	$ 2,776.6	$ 2,828.7	$ 2,947.8
Gas Purchases and Other Costs of Sales	2,163.7	1,678.5	1,709.1	1,766.8
Other Operating Expenses	595.4	620.6	658.2	1,267.9[1]
Operating Income	534.2	477.5	461.4	(86.9)
Other Income and (Expenses)	(262.5)	(261.8)	(258.3)	(280.8)
Income from Continuing Operations Before Income Taxes	271.7	215.7	203.1	(367.7)
Income Taxes	90.4	53.0	60.0	70.7
Income from Continuing Operations	181.3	162.7	143.1	(438.4)
Income (Loss) on Disposal of Discontinued Operations, Net of Tax	12.4	(5.5)	1.1	15.2
Net Income	$ 193.7	$ 157.2	$ 144.2	$ (423.2)
Basic Earnings (Loss) Per Common Share:				
Income from Continuing Operations	$ 1.36	$ 1.23	$ 1.07	$ (3.29)
Income (Loss) on Disposal of Discontinued Operations	0.09	(0.05)	0.01	0.12
Total Basic Earnings Per Common Share	$ 1.45	$ 1.18	$ 1.08	$ (3.17)
Number of Shares Used in Computing Basic Earnings Per Common Share	133.7	132.8	133.1	133.3
Diluted Earnings (Loss) Per Common Share:				
Income from Continuing Operations	$ 1.34	$ 1.21	$ 1.06	$ (3.24)
Income (Loss) on Disposal of Discontinued Operations	0.09	(0.04)	0.01	0.11
Total Diluted Earnings Per Common Share	$ 1.43	$ 1.17	$ 1.07	$ (3.13)
Number of Shares Used in Computing Diluted Earnings Per Common Share	135.0	134.9	135.1	135.2

[1] Includes a charge of $651.7 million to record an impairment of assets; see Note 6.

SELECTED QUARTERLY FINANCIAL DATA
KINDER MORGAN, INC. AND SUBSIDIARIES
Quarterly Operating Results for 2005

	Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(In millions except per share amounts) (Unaudited)			
Operating Revenues	$ 215.8	$ 234.0	$ 246.7	$ 558.0
Gas Purchases and Other Costs of Sales	41.9	63.6	82.3	271.0
Other Operating Expenses	74.9	82.8	81.6	132.5[1]
Operating Income	99.0	87.6	82.8	154.5
Other Income and (Expenses)	113.1	122.6	107.2	108.6
Income from Continuing Operations Before Income Taxes	212.1	210.2	190.0	263.1
Income Taxes	83.6	88.5	77.2	96.2
Income from Continuing Operations	128.5	121.7	112.8	166.9
Income (Loss) from Discontinued Operations, Net of Tax	14.8	0.3	(3.7)	13.3
Net Income	$ 143.3	$ 122.0	$ 109.1	$ 180.2
Basic Earnings (Loss) Per Common Share:				
Income from Continuing Operations	$ 1.04	$ 1.00	$ 0.92	$ 1.32
Income (Loss) from Discontinued Operations	0.12	-	(0.03)	0.11
Total Basic Earnings Per Common Share	$ 1.16	$ 1.00	$ 0.89	$ 1.43
Number of Shares Used in Computing Basic Earnings Per Common Share	123.2	122.0	122.5	126.1
Diluted Earnings (Loss) Per Common Share:				
Income from Continuing Operations	$ 1.03	$ 0.99	$ 0.91	$ 1.31
Income (Loss) from Discontinued Operations	0.12	-	(0.03)	0.11
Total Diluted Earnings Per Common Share	$ 1.15	$ 0.99	$ 0.88	$ 1.42
Number of Shares Used in Computing Diluted Earnings Per Common Share	124.4	123.1	123.7	127.2

[1] Includes a charge of $6.5 million to record an impairment of certain of our Power assets; see Note 6.

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The Supplementary Information on Oil and Gas Producing Activities is presented as required by SFAS No. 69, *Disclosures about Oil and Gas Producing Activities*. The supplemental information includes capitalized costs related to oil and gas producing activities; costs incurred for the acquisition of oil and gas producing activities, exploration and development activities; and the results of operations from oil and gas producing activities.

Kinder Morgan CO_2 Company, L.P. and its consolidated subsidiaries (subsidiaries of Kinder Morgan Energy Partners) represent our only oil and gas producing activities. As discussed in Note 1(B) of the accompanying Notes to Consolidated Financial Statements, due to our adoption of EITF No. 04-5, beginning January 1, 2006, the accounts, balances and results of operations of Kinder Morgan Energy Partners are included in our consolidated financial statements and we no longer apply the equity method of accounting to our investment in Kinder Morgan Energy Partners. Therefore, the following supplemental information on oil and gas producing activities reflects our proportionate share of Kinder Morgan Energy Partners' capitalized costs, costs incurred and results of operations from oil and gas producing activities for the years 2005, 2004 and 2003, when we accounted for Kinder Morgan Energy Partners under the equity method.

Supplemental information is also provided for per unit production costs; oil and gas production and average sales prices; the estimated quantities of proved oil and gas reserves; the standardized measure of discounted future net cash flows associated with proved oil and gas reserves; and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved oil and gas reserves.

Our capitalized costs consisted of the following (in millions):

Capitalized Costs Related to Oil and Gas Producing Activities

	December 31,		
Consolidated Companies	**2006**[a]	**2005**[b]	**2004**[b]
Wells and equipment, facilities and other	$ 1,369.5	$ 166.8	$ 150.7
Leasehold	347.4	48.7	58.2
Total proved oil and gas properties	1,716.9	215.5	208.9
Accumulated depreciation and depletion	(470.2)	(46.1)	(32.3)
Net capitalized costs	$ 1,246.7	$ 169.4	$ 176.6

[a] Amounts relate to Kinder Morgan CO_2 Company, L.P. and its consolidated subsidiaries.

[b] For the period presented, we accounted for Kinder Morgan Energy Partners under the equity method, therefore, amounts reflect our proportionate share of Kinder Morgan Energy Partners' capitalized costs related to oil and gas producing activities.

Includes capitalized asset retirement costs and associated accumulated depreciation. There are no capitalized costs associated with unproved oil and gas properties for the periods reported.

Our costs incurred for property acquisition, exploration and development were as follows (in millions):

Costs Incurred in Exploration, Property Acquisitions and Development

	Year Ended December 31,		
Consolidated Companies	**2006**[a]	**2005**[b]	**2004**[b]
Property Acquisition			
Proved oil and gas properties	$ 36.6	$ 1.0	$ -
Development	261.8	42.8	54.3

[a] Amounts relate to Kinder Morgan CO2 Company, L.P. and its consolidated subsidiaries.

[b] During the period presented, we accounted for Kinder Morgan Energy Partners under the equity method, therefore, amounts reflect our proportionate share of Kinder Morgan Energy Partners' costs incurred in exploration, property acquisitions and development.

There are no capitalized costs associated with unproved oil and gas properties for the periods reported. All capital expenditures were made to develop our proved oil and gas properties and no exploration costs were incurred for the periods reported.

Our results of operations from oil and gas producing activities for each of the years 2006, 2005 and 2004 are shown in the following table (in millions):

Results of Operations for Oil and Gas Producing Activities

	Year Ended December 31,		
Consolidated Companies	**2006**[a]	**2005**[b]	**2004**[b]
Revenues(c)	$ 524.7		
Expenses:			
Production costs	208.9		
Other operating expenses(d)	66.4		
Depreciation, depletion and amortization expenses	169.4		
Total expenses	444.7		
Results of operations for oil and gas producing activities	$ 80.0	$ 18.2	$ 15.2

[a] Amounts relate to Kinder Morgan CO2 Company, L.P. and its consolidated subsidiaries.

[b] During the period presented, we accounted for Kinder Morgan Energy Partners under the equity method, therefore, amounts reflect our proportionate share of Kinder Morgan Energy Partners' results of operations for oil and gas producing activities.

[c] Revenues include losses attributable to our hedging contracts of $441.7 million for the year ended December 31, 2006.

[d] Consists primarily of carbon dioxide expense.

The table below represents estimates, as of December 31, 2006, of proved crude oil, natural gas liquids and natural gas reserves prepared by Netherland, Sewell and Associates, Inc. (independent oil and gas consultants) of Kinder Morgan CO_2 Company, L.P. and its consolidated subsidiaries' interests in oil and gas properties, all of which are located in the state of Texas. This data has been prepared using constant prices and costs, as discussed in subsequent paragraphs of this document. The estimates of reserves and future revenue in this document conforms to the guidelines of the United States Securities and Exchange Commission.

We believe the geologic and engineering data examined provides reasonable assurance that the proved reserves are recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are subject to change, either positively or negatively, as additional information becomes available and contractual and economic conditions change.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations or declines based upon future conditions. Proved developed reserves are the quantities of crude oil, natural gas liquids and natural gas expected to be recovered through existing investments in wells and field infrastructure under current operating conditions. Proved undeveloped reserves require additional investments in wells and related infrastructure in order to recover the production.

During 2006, Kinder Morgan Energy Partners filed estimates of our oil and gas reserves for the year 2005 with the Energy Information Administration of the U. S. Department of Energy on Form EIA-23. The data on Form EIA-23 was presented on a different basis, and included 100% of the oil and gas volumes from our operated properties only, regardless of our net interest. The difference between the oil reserves reported on Form EIA-23 and those reported in this report exceeds 5%.

Reserve Quantity Information

	Consolidated Companies		
	Crude Oil (MBbls)	**NGLs (MBbls)**	**Nat. Gas (MMcf)(a)**
Proved developed and undeveloped reserves:			
As of December 31, 2003[b]	22,160	3,091	626
As of December 31, 2004[b]	22,862	3,741	294
As of December 31, 2005[b]	21,567	2,884	327
As of January 1, 2006[c]	141,951	18,983	2,153
Revisions of Previous Estimates[c]	(4,615)	(6,858)	(1,408)
Production[c]	(13,811)	(1,817)	(461)
Purchases of Reserves in Place[c]	453	25	7
As of December 31, 2006[c]	123,978	10,333	291
Proved developed reserves:			
As of December 31, 2003[b]	12,330	1,551	485
As of December 31, 2004[b]	13,176	1,640	251
As of December 31, 2005[b]	11,965	1,507	251
As of December 31, 2006[c]	69,073	5,877	291

[a] Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

[b] For the period presented, we accounted for Kinder Morgan Energy Partners under the equity method, therefore, amounts reflect our proportionate share of Kinder Morgan Energy Partners' proved reserves.

[c] Amounts relate to Kinder Morgan CO_2 Company, L.P. and its consolidated subsidaries.

The standardized measure of discounted cash flows and summary of the changes in the standardized measure computation from year-to-year are prepared in accordance with SFAS No. 69. The assumptions that underly the computation of the standardized measure of discounted cash flows may be summarized as follows:

- the standardized measure includes our estimate of proved crude oil, natural gas liquids and natural gas reserves and projected future production volumes based upon year-end economic conditions;
- pricing is applied based upon year-end market prices adjusted for fixed or determinable contracts that are in existence at year-end;
- future development and production costs are determined based upon actual cost at year-end;
- the standardized measure includes projections of future abandonment costs based upon actual costs at year-end; and
- a discount factor of 10% per year is applied annually to the future net cash flows.

Our standardized measure of discounted future net cash flows from proved reserves were as follows (in millions):

Standardized Measure of Discounted Future Net Cash Flows From Proved Oil and Gas Reserves

	As of December 31,		
Consolidated Companies	**2006**[a]	**2005**[b]	**2004**[b]
Future Cash Inflows from Production	$ 7,534.6	$ 1,390.3	$ 1,071.6
Future Production Costs	(2,617.9)	(418.8)	(357.6)
Future Development Costs[c]	(1,256.7)	(132.1)	(92.8)
Undiscounted Future Net Cash Flows	3,660.0	839.4	621.2
10% Annual Discount	(1,452.2)	(372.2)	(243.4)
Standardized Measure of Discounted Future Net Cash Flows	$ 2,207.8	$ 467.2	$ 377.8

[a] Amounts relate to Kinder Morgan CO2 Company, L.P. and its consolidated subsidiaries.

[b] During the period presented, we accounted for Kinder Morgan Energy Partners under the equity method, therefore, amounts reflect our proportionate share of Kinder Morgan Energy Partners' standardized measure of discounted future net cash flows.

[c] Includes abandonment costs.

The following table represents our estimate of changes in the standardized measure of discounted future net cash flows from proved reserves (in millions):

Changes in the Standardized Measure of Discounted Future Net Cash Flows From Proved Oil and Gas Reserves

Consolidated Companies	**2006**[a]	**2005**[b]	**2004**[b]
Present Value as of January 1	$ 3,075.0		
Changes During the Year:			
Revenues Less Production and Other Costs[c]	(690.0)		
Net Changes in Prices, Production and Other Costs[c]	(123.0)		
Development Costs Incurred	261.8		
Net Changes in Future Development Costs	(446.0)		
Purchases of Reserves in Place	3.2		
Revisions of Previous Quantity Estimates	(179.5)		
Improved Recovery	-		
Accretion of Discount	307.4		
Timing Differences and Other	(1.1)		
Net Change For the Year	(867.2)		
Present Value as of December 31	$ 2,207.8	$ 467.2	$ 377.8

[a] Amounts relate to Kinder Morgan CO2 Company, L.P. and its consolidated subsidiaries.

[b] During the period presented, we accounted for Kinder Morgan Energy Partners under the equity method, therefore, amounts reflect our proportionate share of Kinder Morgan Energy Partners' standardized measure of discounted future net cash flows.

[c] Excludes the effect of losses attributable to our hedging contracts of $441.7 million for the year ended December 31, 2006.

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

None.

Item 9A. ***Controls and Procedures.***

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2006, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in *Internal Control – Integrated Framework*, our management concluded that our internal control over financial reporting was effective as of December 31, 2006.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their attestation report which is included herein.

Certain businesses we acquired during 2006 were excluded from the scope of our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006. The excluded businesses consisted of the following:

- the various oil and gas properties acquired from Journey Acquisition – I, L.P. and Journey 2000, L.P. on April 5, 2006. The acquisition was made effective March 1, 2006;
- three terminal operations acquired separately in April 2006: terminal equipment and infrastructure located on the Houston Ship Channel, a rail terminal located at the Port of Houston, and all of the membership interests in Lomita Rail Terminal LLC;
- all of the membership interests of Transload Services, LLC, acquired November 20, 2006;
- all of the membership interests of Devco USA L.L.C., acquired December 1, 2006; and
- the refined petroleum products terminal located in Roanoke, Virginia, acquired from Motiva Enterprises, LLC effective December 15, 2006.

These businesses, in the aggregate, constituted 0.29% of our total operating revenues for 2006 and 0.53% of our total assets as of December 31, 2006.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information.***

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

Directors and Executive Officers

Set forth below is certain information concerning our directors and executive officers. All of our officers serve at the discretion of the board of directors. Our Board of Directors is currently divided into three classes, with the classes having three-year terms that expire in successive years.

Name	Age	Position
Richard D. Kinder	62	Director, Chairman and Chief Executive Officer
Edward H. Austin	65	Director
Charles W. Battey	75	Director
Stewart A. Bliss	73	Director
Ted A. Gardner	49	Director
William J. Hybl	64	Director
Michael C. Morgan	38	Director
Edward Randall, III	80	Director
James M. Stanford	69	Director
Fayez Sarofim	78	Director
H. A. True, III	64	Director
Douglas W.G. Whitehead	60	Director
C. Park Shaper	38	President
Steven J. Kean	45	Executive Vice President and Chief Operating Officer
Kimberly A. Dang	37	Vice President, Investor Relations and Chief Financial Officer
Ian D. Anderson	49	President, Kinder Morgan Canada
R. L. (Randy) Jespersen	52	President, Terasen Gas
David D. Kinder	32	Vice President, Corporate Development and Treasurer
Joseph Listengart	38	Vice President, General Counsel and Secretary
Scott E. Parker	46	Vice President (President, Natural Gas Pipelines)
James E. Street	50	Vice President, Human Resources and Administration
Daniel E. Watson	48	Vice President (President, Retail)

Richard D. Kinder is Director, Chairman and Chief Executive Officer of Kinder Morgan, Inc., Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc. Mr. Kinder has served as Director, Chairman and Chief Executive Officer of Kinder Morgan Management, LLC since its formation in February 2001. He was elected Director, Chairman and Chief Executive Officer of Kinder Morgan, Inc. in October 1999. He was elected Director, Chairman and Chief Executive Officer of Kinder Morgan G.P., Inc. in February 1997. Mr. Kinder was elected President of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. in July 2004 and served as President until May 2005. Mr. Kinder is the uncle of David Kinder, Vice President, Corporate Development and Treasurer of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc.

Edward H. Austin, Jr. has been one of our directors since 1994. Mr. Austin has served as a Director and Executive Vice President of Austin, Calvert & Flavin, Inc., an investment advisory firm based in San Antonio, Texas since August 1999. Austin, Calvert & Flavin, Inc., is a wholly owned subsidiary of Waddell & Reed Financial, Inc.

Charles W. Battey has been one of our directors since 1971. Mr. Battey has been an independent consultant and an active community volunteer based in Kansas City for the past five years. Mr. Battey was Chairman of our Board from 1989 to 1996, and our Chief Executive Officer from 1989 to 1994.

Stewart A. Bliss has been one of our directors since 1993. Mr. Bliss has been an Independent Financial Consultant and Senior Business Advisor in Denver, Colorado for the past thirteen years. Mr. Bliss served on the Governing Board for the Colorado State University System from 1994 to February 2001 and was President of the Board from 1999 to 2001. Mr. Bliss served as our Interim Chairman and Chief Executive Officer from July to October of 1999.

Ted A. Gardner has been one of our directors since 1999. Mr. Gardner has been Managing Partner of Silverhawk Capital Partners since June 2005 and has been a private investor since July 2003. Mr. Gardner served as Managing Partner of Wachovia Capital Partners and a Senior Vice President of Wachovia Corporation from 1990 to June 30, 2003. Mr. Gardner is also a director of Encore Acquisition Company and COMSYS IT Partners, Inc.

William J. Hybl has been one of our directors since 1988. Mr. Hybl has been the Chairman, Chief Executive Officer and a Trustee of El Pomar Foundation, a charitable foundation based in Colorado Springs, Colorado for the past 25 years.

Michael C. Morgan has been one of our directors since 2003. Mr. Morgan has been President of Portcullis Partners, L.P., a private investment partnership, since October 2004. Mr. Morgan was President of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and us from July 2001 to July 2004. Mr. Morgan served as Vice President-Strategy and Investor Relations of Kinder Morgan Management, LLC from February 2001 to July 2001. He served as Vice President-Strategy and Investor Relations of us and Kinder Morgan G.P., Inc. from January 2000 to July 2001. He served as Vice President, Corporate Development of Kinder Morgan G.P., Inc. from February 1997 to January 2000. Mr. Morgan was our Vice President, Corporate Development from October 1999 to January 2000.

Edward Randall, III has been one of our directors since 1994. Mr. Randall has been a private investor for the past five years.

Fayez Sarofim has been one of our directors since 1999. Mr. Sarofim has been President and Chairman of the Board of Fayez Sarofim & Co., an investment advisory firm based in Houston, Texas, since he founded it in 1958. Mr. Sarofim is a director of Unitrin, Inc. and Argonaut Group, Inc.

James M. Stanford has been one of our directors since 2006. Mr. Stanford has been the President of Stanford Resource Management Inc., a natural resources consulting firm based in Calgary, Alberta, for the past five years. Mr. Stanford is a director of Encana Corporation, Nova Chemicals Corporation and OPTI Canada Inc. Mr. Stanford was, in accordance with our By-Laws, elected as a Class II Director at our January 2006 Board of Directors meeting and was appointed to the Board's Compensation Committee. Mr. Stanford was elected for a term ending in 2007.

H. A. True, III has been one of our directors since 1991. Mr. True has been an owner, officer and director of the True Companies, which are involved in energy, agriculture and financing, and based in Casper, Wyoming for the past five years.

Douglas W. G. Whitehead has been one of our directors since 2006. Mr. Whitehead has for the past five years served as President and Chief Executive Officer of Finning International Inc., which sells, rents and services Caterpillar and complementary equipment in Western Canada, the United Kingdom and South America, and which is based in Vancouver, British Columbia. Mr. Whitehead is a director of Finning International Inc. and Ballard Power Systems, Inc. Mr. Whitehead was, in accordance with our By-Laws, elected as a Class III Director at our January 2006 Board of Directors meeting and was appointed to the Board's Audit Committee. Mr. Whitehead was elected for a term ending in 2008.

C. Park Shaper is Director and President of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc. and President of Kinder Morgan, Inc. Mr. Shaper was elected President of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. in May 2005. He served as Executive Vice President of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. from July 2004 until May 2005. Mr. Shaper was elected Director of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc. in January 2003. He was elected Vice President, Treasurer and Chief Financial Officer of Kinder Morgan Management, LLC upon its formation in February 2001, and served as its Treasurer until January 2004, and its Chief Financial Officer until May 2005. He was elected Vice President, Treasurer and Chief Financial Officer of Kinder Morgan, Inc. and Kinder Morgan G.P., Inc. in January 2000, and served as their Treasurer until January 2004, and their Chief Financial Officer until May 2005. He received a Masters of Business Administration degree from the J.L. Kellogg Graduate School of Management at Northwestern University. Mr. Shaper also has a Bachelor of Science degree in Industrial Engineering and a Bachelor of Arts degree in Quantitative Economics from Stanford University.

Steven J. Kean is Executive Vice President and Chief Operating Officer of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. Mr. Kean was elected Executive Vice President and Chief Operating Officer of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. in January 2006. He served as Executive Vice President, Operations of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. from May 2005 to January 2006. He served as President, Texas Intrastate Pipeline Group from June 2002 until May 2005. He served as Vice President of Strategic Planning for the Kinder Morgan Gas Pipeline Group from January 2002 until June 2002. Until December 2001, Mr. Kean was Executive Vice President and Chief of Staff of Enron Corp. Mr. Kean received his Juris Doctor from the University of Iowa in May 1985 and received a Bachelor of Arts degree from Iowa State University in May 1982.

Kimberly A. Dang, formerly Kimberly J. Allen, is Vice President, Investor Relations and Chief Financial Officer of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. Mrs. Dang was elected Chief Financial Officer of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. in May 2005. She served as Treasurer of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. from January 2004 to May 2005. She was elected Vice President, Investor Relations of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. in July 2002. From November 2001 to July 2002, she served as Director, Investor Relations. From May 2001 until November 2001, Mrs. Dang was an independent financial consultant. From September 2000 until May 2001, she served as an associate and later a principal at Murphee Venture Partners, a venture capital firm. Mrs. Dang has received a Masters in Business Administration degree from the J.L. Kellogg Graduate School of Management at Northwestern University and a Bachelor of Business Administration degree in accounting from Texas A&M University.

Ian D. Anderson is President of Kinder Morgan Canada. Mr. Anderson was elected President, Kinder Morgan Canada in November 2005. He served as Vice President, Finance and Corporate Services, Terasen Pipelines Inc. from July 2004 to November 2005. Mr. Anderson was Vice President, Finance and Corporate Controller, Terasen Inc. from August 2002 to July 2004 and he was Vice President, Finance and Regulatory Affairs at Centra Gas British Columbia (which became Terasen Gas (Vancouver Island) Inc. in 2003) from December 1999 to August 2002. Mr. Anderson is a Certified Management Accountant, and is a 1997 graduate of the University of Michigan Executive Program.

R.L. (Randy) Jespersen is President of Terasen Gas Inc. (formerly BC Gas Utility Ltd.) and Terasen Gas (Vancouver Island) Inc. Mr. Jespersen was appointed President of Terasen Gas (Vancouver Island) Inc. in January 2004, and appointed President of Terasen Gas Inc. in January 2002. He served as Senior Vice President, Energy Delivery Services from April 1998 through December 2001, and Senior Vice President, Gas Supply from March 1996 to April 1998. Mr. Jespersen received his Masters in Business Administration from the University of Saskatchewan in 1976, his B.Sc. (Business) degree from Oregon State University in 1975, and has a Business Diploma from Lethbridge Community College.

David D. Kinder is Vice President, Corporate Development and Treasurer of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. Mr. Kinder was elected Treasurer of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. in May 2005. He was elected Vice President, Corporate Development of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. in October 2002. He served as manager of corporate development for Kinder Morgan, Inc. and Kinder Morgan G.P., Inc. from January 2000 to October 2002. Mr. Kinder graduated cum laude with a Bachelors degree in Finance from Texas Christian University in 1996. Mr. Kinder is the nephew of Richard D. Kinder.

Joseph Listengart is Vice President, General Counsel and Secretary of Kinder Morgan, Inc., Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc. Mr. Listengart was elected Vice President, General Counsel and Secretary of Kinder Morgan Management, LLC upon its formation in February 2001. He was elected Vice President and General Counsel of Kinder Morgan G.P., Inc. and Vice President, General Counsel and Secretary of Kinder Morgan, Inc. in October 1999. Mr. Listengart was elected Secretary of Kinder Morgan G.P., Inc. in November 1998 and has been an employee of Kinder Morgan G.P., Inc. since March 1998. Mr. Listengart received his Masters in Business Administration from Boston University in January 1995, his Juris Doctor, magna cum laude, from Boston University in May 1994, and his Bachelor of Arts degree in Economics from Stanford University in June 1990.

Scott E. Parker is Vice President (President, Natural Gas Pipelines) of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. He was elected Vice President (President, Natural Gas Pipelines) of Kinder Morgan Management, LLC, Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. in May 2005. Mr. Parker served as President of NGPL from March 2003 to May 2005. Mr. Parker served as Vice President, Business Development of NGPL from January 2001 to March 2003. He held various positions at NGPL from January 1984 to January 2001. Mr. Parker holds a Bachelor's degree in accounting from Governors State University.

James E. Street is Vice President, Human Resources and Administration of Kinder Morgan, Inc., Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc. Mr. Street was elected Vice President, Human Resources and Administration of Kinder Morgan Management, LLC upon its formation in February 2001. He was elected Vice President, Human Resources and Administration of Kinder Morgan G.P., Inc. and Kinder Morgan, Inc. in August 1999. Mr. Street received a Masters of Business Administration degree from the University of Nebraska at Omaha and a Bachelor of Science degree from the University of Nebraska at Kearney.

Daniel E. Watson is Vice President (President, Retail) for Kinder Morgan, Inc. Mr. Watson was elected Vice President (President, Retail) in October 1999. Mr. Watson also holds the title of President of Rocky Mountain Natural Gas Company, a Kinder Morgan, Inc. subsidiary. He has served as President, Rocky Mountain Natural Gas Company since October 1999. Mr. Watson received a Bachelor of Science degree in Geological Engineering in December 1979, and a Bachelor of Science degree in Mining Engineering in May 1980, from the South Dakota School of Mines and Technology.

Corporate Governance

We have a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934 comprised of Messrs. Austin, Battey, Bliss and Whitehead. Mr. Bliss is the chairman of the audit committee. Our Board has determined that Mr. Battey is an "audit committee financial expert." The Board has determined that all of the members of the audit committee are independent as described under the relevant standards.

We have not made, within the preceding three years, contributions to any tax-exempt organization in which any of our independent directors serves as an executive officer that in any single fiscal year exceeded the greater of $1.0 million or 2% of such tax-exempt organization's consolidated gross revenues.

On April 11, 2006, our chief executive officer certified to the New York Stock Exchange, as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual, that as of April 11, 2006, he was not aware of any violation by us of the New York Stock Exchange's Corporate Governance listing standards. We have also filed as an exhibit to this report the Sarbanes-Oxley Act Section 302 certifications regarding the quality of our public disclosure.

We make available free of charge within the "Investors" section of our Internet website, at www.kindermorgan.com, and in print to any stockholder who requests, the governance guidelines, the charters of the audit committee, compensation committee and nominating and governance committee, and our code of business conduct and ethics (which applies to our senior financial and accounting officers and our chief executive officer, among others). Requests for copies may be directed to Investor Relations, Kinder Morgan, Inc., 500 Dallas, Suite 1000, Houston, Texas 77002, or by telephone at (713) 369-9490. We intend to disclose any amendments to our code of business conduct and ethics, and any waiver from a provision of that code granted to our executive officers or directors, that otherwise would be required to be disclosed on a Form 8-K, on our website within four business days following such amendment or waiver. The information contained on or connected to our Internet website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the Securities and Exchange Commission.

Interested parties may contact our lead director, the chairpersons of any of the board's committees, the independent directors as a group or the full board by mail to Kinder Morgan, Inc., 500 Dallas Street, Suite 1000, Houston, Texas 77002, Attention: General Counsel, or by e-mail within the "Contact Us" section of our Internet website, at www.kindermorgan.com. Any communication should specify the intended recipient.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Securities Exchange Act of 1934, as amended, requires our directors and officers, and persons who own more than 10% of a registered class of our equity securities to file initial reports of ownership and reports of changes in ownership with the Securities and Exchange Commission. Such persons are required by Commission regulation to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and directors, we believe that all Section 16(a) filing requirements were met during 2006.

(B) Involvement in Certain Legal Proceedings

None.

Item 11. ***Executive Compensation.***

Certain of our executive officers, including all but one of the named executive officers identified below, also serve in the same capacities as executive officers of Kinder Morgan G.P., Inc., the general partner of Kinder Morgan Energy Partners, and Kinder Morgan Management, the delegate of Kinder Morgan G.P., Inc. All information in this Item 11 with respect to compensation of executive officers describes the total compensation received by those persons in all capacities for us, Kinder Morgan G.P., Inc., Kinder Morgan Management, and their respective affiliates.

Compensation Discussion and Analysis

Most of our executive officers are based in the United States, but some of our executive officers, including one of the named executive officers identified below (Mr. R. L. (Randy) Jespersen), are based in Canada. The following Compensation Discussion and Analysis focuses on the components of our compensation program applicable to our United States-based executive officers and describes the components of our compensation program applicable to our Canada-based executive officers where it differs.

Program Objectives

We seek to attract and retain executives who will help us achieve our primary business strategy objective of growing the value of our portfolio of businesses for the benefit of our stockholders. To help accomplish this goal, we have designed an executive compensation program that rewards individuals with competitive compensation that consists of a mix of cash, benefit plans and long-term compensation, with a majority of executive compensation tied to the "at risk" portions of the annual cash bonus and long-term equity compensation.

The key objectives of our executive compensation program are to attract, motivate and retain executives who will advance our overall business strategies and objectives to create and return value to our stockholders. We believe that an effective executive compensation program should link total compensation to financial performance and to the attainment of short and long term strategic, operational, and financial objectives. We also believe it should provide competitive total compensation opportunities at a reasonable cost. In designing our executive compensation program, we have recognized that our executives have a much greater portion of their overall compensation at-risk than do our other employees; consequently, we have tried to establish the at-risk portions of our executive total compensation at levels that recognize their much increased level of responsibility and their ability to influence business results.

Our executive compensation program is principally comprised of the following three elements:

- base cash salary;
- possible annual cash bonus (reflected in the Summary Compensation Table below as Non-Equity Incentive Plan Compensation); and
- possible long-term equity awards, namely grants of restricted stock and, in previous years, grants of options to acquire shares of common stock.

It is our current philosophy to pay our executive officers a base salary not to exceed $200,000 (C$250,000 for our Canada-based executives) per year, which is below base salaries for comparable positions in the marketplace. In addition, we believe that the compensation of our Chief Executive Officer, Chief Financial Officer and the executives named below, collectively referred to in this Item 11. as our named executive officers, should be directly and materially tied to our financial performance, and should be aligned with the interests of our stockholders. Therefore, the majority of our named executive officers' compensation is allocated to the "at risk" portions of our compensation program—the annual cash bonus and the long-term equity compensation. For 2006, our executive compensation was weighted toward the cash bonus, payable on the basis of achieving (i) an earnings per share target by us; and (ii) a cash distribution per common unit target by Kinder Morgan Energy Partners. Prior to 2003, we used both stock options and restricted stock as the principal components of long-term executive compensation, and beginning in 2003, we used grants of restricted stock exclusively as the principal component of long-term executive compensation.

Grants of restricted stock are made to encourage our executive officers to manage from the perspective of owners with an equity stake, and our approach to equity compensation is designed to balance the business objective of fair and reasonable executive pay with the business objectives of equityholder interests. We are very sensitive to making large awards of restricted stock or stock options to our executive officers because such large awards dilute the ownership of our stockholders. Therefore, we seek to balance the dilutive effect of such stock awards to our existing stockholders with our need to attract and retain key employees.

Additionally, we periodically compare our executive compensation components with market information. The purpose of this comparison is to ensure that our total compensation package operates effectively, remains both reasonable and competitive with the energy industry, and is generally comparable to the compensation offered by companies of similar size and scope as us. We also keep abreast of current trends, developments, and emerging issues in executive compensation, and if appropriate, will obtain advice and assistance from outside legal, compensation or other advisors.

We have endeavored to design our executive compensation program and practices with appropriate consideration of all tax, accounting, legal and regulatory requirements. Section 162(m) of the Internal Revenue Code limits the deductibility of certain compensation for our executive officers to $1,000,000 of compensation per year; however, if specified conditions are met, certain compensation may be excluded from consideration of the $1,000,000 limit. Since the bonuses we pay to our executive officers are paid under our stockholder-approved 2005 Annual Incentive Plan as a result of reaching designated financial targets established by our compensation committee, we expect that all compensation paid to our executives will be deductible by us.

Our compensation philosophy with respect to our Canada-based executives is the same as for our U.S.-based executives, but different laws and regulations affect the manner in which we structure the compensation program for our Canada-based executives. We generally enter into written employment agreements with our Canada-based executives, whereas we do not have written employment agreements with our executives in the United States (except for Mr. Richard D. Kinder). In addition, due to differing employment and tax laws and regulations, we make available to our Canada-based employees a pension plan that differs from our U.S. pension plan and grant our Canada-based executives restricted stock units, rather than restricted stock, under our Amended and Restated 1999 Stock Plan. Also, to account for the Canadian dollar-U.S. dollar exchange rate, we pay our Canada-based executives a base salary not to exceed C$250,000 per year. None of our Canada-based executive officers serve as executive officers of Kinder Morgan G.P., Inc. or Kinder Morgan Management.

Behaviors Designed to Reward

Our executive compensation program is designed to reward individuals for advancing our business strategies and the interests of our stakeholders, and we prohibit engaging in any detrimental activities, such as performing services for a competitor, disclosing confidential information or violating appropriate business conduct standards. Each executive is held accountable to uphold and comply with company guidelines, which require the individual to maintain a discrimination-free workplace, to comply with orders of regulatory bodies, and to maintain high standards of operating safety and environmental protection.

Unlike many companies, we have no executive perquisites and, with respect to our United States-based executives, we have no supplemental executive retirement, non-qualified supplemental defined benefit/contribution, deferred compensation or split dollar life insurance programs. Due to different laws and regulations in Canada, we do have a supplemental defined benefit plan for our Canada-based executives. We have no executive company cars or executive car allowances nor do we offer or pay for financial planning services. Additionally, we do not own any corporate aircraft and we do not pay for executives to fly first class. We are currently below competitive levels for comparable companies in this area of our compensation package; however, we have no current plans to change our policy of not offering such executive benefits or perquisite programs.

At his request, Mr. Kinder, our Chairman and Chief Executive Officer, receives $1 of base salary per year. Additionally, Mr. Kinder has requested that he receive no annual bonus, stock or unit grants, or other compensation. Mr. Kinder does not have any deferred compensation, supplemental retirement or any other special benefit, compensation or perquisite arrangement. He wishes to be rewarded strictly on the basis of stock performance which impacts the value of his holdings of Kinder Morgan, Inc. common stock, Kinder Morgan Energy Partners common units and Kinder Morgan Management shares. Each year Mr. Kinder reimburses us for his portion of health care premiums and parking expenses.

Elements of Compensation

As outlined above, our executive compensation program is principally comprised of the following three elements: a base cash salary; a possible annual cash bonus; and a possible long-term equity award. With regard to our executive officers other than our Chief Executive Officer, our and Kinder Morgan Management's compensation committees review and approve annually the financial goals and objectives of both Kinder Morgan Energy Partners and us that are relevant to the compensation of our executive officers. Generally following the regularly scheduled fourth quarter Board meetings in each year, the committees solicit information from other directors, the Chief Executive Officer and other relevant members of senior management regarding the performance of our executive officers other than our Chief Executive Officer during that year. Our Chief Executive Officer makes compensation recommendations to the committees with respect to our executive officers, other than himself. The committees obtain the information and the recommendations prior to the regularly scheduled first quarter Board meetings.

Annually, at our and Kinder Morgan Management's regularly scheduled first quarter Board meetings, the committees evaluate the performance of our executive officers other than our Chief Executive Officer and make determinations regarding the terms of their continued employment and compensation for that year. If the committees deem it advisable, they may, rather than determine the terms of continued employment and compensation for executive officers (other than the Chief Executive Officer), make a recommendation with respect thereto to the independent members of the Board, who make the determination at the first quarter Board meetings. The committees also determine bonuses for the prior year based on the performance targets set therefor, and set performance targets for the present year for bonus and other relevant purposes.

If any executive officer of Kinder Morgan, Inc. is also an executive officer of Kinder Morgan Management or Kinder Morgan G.P., Inc., the committees' compensation determination or recommendation (i) may be with respect to the aggregate compensation to be received by such officer from us, Kinder Morgan Management, and Kinder Morgan G.P., Inc. that is to be allocated among them in accordance with procedures approved by the committees, if such aggregate compensation set by our compensation committee or our Board and that set by the compensation committee or the Board of Kinder Morgan Management are the same, or alternatively (ii) may be with respect to the compensation to be received by such executive officers from us, Kinder Morgan Management or Kinder Morgan G.P., Inc., as the case may be, in which case such compensation will not be allocated among us, on the one hand, and Kinder Morgan Management, Kinder Morgan G.P., Inc. and Kinder Morgan Energy Partners, on the other. Further, if any executive officer of Kinder Morgan, Inc. is also an executive officer of Kinder Morgan Management, the committees may, to the extent they believe necessary or desirable, exchange information with respect to evaluation and compensation recommendations with each other. Thereafter, the committees or the Chief Executive Officer will discuss the committees' evaluation and the determination as to compensation with the executive officers.

In addition, the compensation committees have the sole authority to retain (and terminate as necessary) and compensate any compensation consultants, counsel and other firms of experts to advise them as they determine necessary or appropriate. The committees have the sole authority to approve any such firm's fees and other retention terms, and we will make adequate provision for the payment of all fees and other compensation, approved by the committees, to any such firm employed by the committees. The committees also have sole authority to determine if any compensation consultant is to be used to assist in the evaluation of director, Chief Executive Officer or senior executive compensation and will have sole authority to retain and terminate any such compensation consultant and to approve the consultant's fees and other retention terms.

Base Salary

This includes base salary, which is paid in cash. All of our executive officers, with the exception of our Chairman and Chief Executive Officer, who receives $1 of base salary per year as described above, earn a base salary not to exceed $200,000 per year (C$250,000 per year for our Canada-based executive officers). Generally, we believe that our executive officers' base salaries are below base salaries for executives in similar positions and with similar responsibilities at comparable companies of corresponding size and scope.

Possible Annual Cash Bonus (Non-Equity Cash Incentive)

Our possible annual cash bonuses are provided for under our 2005 Annual Incentive Plan, which became effective January 18, 2005 and which is referred to in this report as the Annual Incentive Plan. The overall purpose of the Annual Incentive Plan is to increase our executive officers' and our employees' personal stake in our continued success by providing them additional incentives through the possible payment of annual cash bonuses. Under the plan, annual cash bonuses may be paid to our executive officers and other employees depending on a variety of factors, including their individual performance, our financial performance, the financial performance of our subsidiaries, and safety and environmental goals.

The plan is administered by the compensation committee of our Board of Directors, which consists of three or more directors, each of whom qualifies as an "outside director" for purposes of the Internal Revenue Code. The compensation committee is authorized to grant awards under the plan, interpret the plan, adopt rules and regulations for carrying out the plan, and make all determinations necessary or advisable for the administration of the plan.

All of our employees and those of our subsidiaries, including KMGP Services Company, Inc., are eligible to participate in the plan, except employees who are included in a unit of employees covered by a collective bargaining agreement unless such agreement expressly provides for eligibility under the plan. However, only eligible employees who are selected by our compensation committee will actually participate in the plan and receive bonuses.

The plan consists of two components: the executive plan component and the non-executive plan component. Our Chairman and Chief Executive Officer and all employees who report directly to the Chairman are eligible for the executive plan component; however, as stated elsewhere in this report, Mr. Richard D. Kinder, our Chairman and Chief Executive Officer, does not participate under the plan. As of January 31, 2007, excluding Mr. Richard D. Kinder, 13 of our current executive officers were eligible to participate in the executive plan component. All other U.S. eligible employees were eligible for the non-executive plan component.

Our compensation committee determines which of the eligible employees will be eligible to participate under the executive plan component of the Annual Incentive Plan for any given year. At or before the start of each calendar year (or later, to the extent allowed under Internal Revenue Code regulations), performance objectives for that year are identified. The performance objectives are based on one or more of the criteria set forth in the plan. Our compensation committee establishes a bonus opportunity for each executive officer, which is the amount of the bonus the executive officer will earn if the performance objectives are fully satisfied. The compensation committee may specify a minimum acceptable level of achievement of each performance objective below which no bonus is payable with respect to that objective. The compensation

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committee may set additional levels above the minimum (which may also be above the targeted performance objective), with a formula to determine the percentage of the bonus opportunity to be earned at each level of achievement above the minimum. Performance at a level above the targeted performance objective may entitle the executive officer to earn a bonus in excess of 100% of the bonus opportunity. However, the maximum payout to any individual under the Annual Incentive Plan for any year is $2.0 million, and our compensation committee has the discretion to reduce the bonus amount in any performance period.

Performance objectives may be based on one or more of the following criteria:

- Our earnings per share;
- Our cash dividends to our stockholders;
- Our earnings before interest and taxes or earnings before interest, taxes and corporate charges, or the earnings before interest and taxes or earnings before interest, taxes and corporate charges of one of our subsidiaries or business units;
- Our net income or the net income of one of our subsidiaries or business units;
- Our revenues or the revenues of one of our subsidiaries or business units;
- Our unit revenues minus unit variable costs or the unit revenues minus unit variable costs of one of our subsidiaries or business units;
- Our return on capital, return on equity, return on assets, or return on invested capital, or the return on capital, return on equity, return on assets, or return on invested capital of one of our subsidiaries or business units;
- Our cash flow return on assets or cash flows from operating activities, or the cash flow return on assets or cash flows from operating activities of one of our subsidiaries or business units;
- Our capital expenditures or the capital expenditures of one of our subsidiaries or business units;
- Our operations and maintenance expense or general and administrative expense, or the operations and maintenance expense or general and administrative expense of one of our subsidiaries or business units;
- Our debt-equity ratios and key profitability ratios, or the debt-equity ratios and key profitability ratios of one of our subsidiaries or business units; or
- Our stock price.

Our compensation committee set two performance objectives for 2006 under both the executive plan component and the non-executive plan component. The 2006 performance objectives were $3.28 in cash distributions per common unit at Kinder Morgan Energy Partners, and $5.00 in earnings per share at Kinder Morgan, Inc. These targets were the same as our previously disclosed 2006 budget expectations. At the end of 2006, our compensation committee determined and certified in writing the extent to which the performance objectives had been attained and the extent to which the bonus opportunity had been earned under the formula previously established by our compensation committee. Because payments under the plan for our executive officers are determined by comparing actual performance to the performance objectives established by the compensation committee each year for eligible executive officers chosen to participate for that year, it is not possible to accurately predict any amounts that will actually be paid under the executive plan portion of the plan over the life of the plan.

The below table sets forth the bonus opportunities that would have been payable to the named executive officers if the performance objectives established by our compensation committee for 2006 had been 100% achieved. Our compensation committee may, at its sole discretion, reduce the amount of the bonus actually paid to any executive officer under the plan from the amount of any bonus opportunity open to such executive officer.

Annual Incentive Plan
Bonus Opportunities for 2006[1]

Name and Principal Position	Dollar Value
Richard D. Kinder, Chairman and Chief Executive Officer	$ –[2]
Kimberly A. Dang, Vice President and Chief Financial Officer	1,000,000[3]
David D. Kinder, Vice President, Corporate Development and Treasurer	1,000,000[3]
Steven J. Kean, Executive Vice President and Chief Operating Officer	1,500,000[4]
Joseph Listengart, Vice President, General Counsel and Secretary	1,000,000[3]
Scott E. Parker, Vice President (President, Natural Gas Pipelines)	1,000,000[3]
C. Park Shaper, President	1,500,000[4]
R. L. (Randy) Jespersen, President, Terasen Gas	1,000,000[3]

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1 No stock, stock options, stock appreciation rights, restricted stock or similar awards are payable under the plan.

2 Declined to participate.

3 Under the plan, for 2006, if neither of the targets was met, no bonus opportunities would have been provided; if one of the targets was met, $500,000 in bonus opportunities would have been open; if both of the targets had been exceeded by 10%, $1,500,000 in bonus opportunities would have been open. Our compensation committee may, in its sole discretion, reduce the award payable to any participant for any reason.

4 Under the plan, for 2006, if neither of the targets was met, no bonus opportunities would have been provided; if one of the targets was met, $750,000 in bonus opportunities would have been open; if both of the targets had been exceeded by 10%, $2,000,000 in bonus opportunities would have been open. Our compensation committee may, in its sole discretion, reduce the award payable to any participant for any reason.

In 2006, excluding the impairment charge resulting from our entering into a definitive agreement to sell our Terasen Gas business segment, Kinder Morgan, Inc. exceeded its established target, but Kinder Morgan Energy Partners did not achieve its established target. Excluding Mr. Richard D. Kinder, who does not participate in the plan, our top three executive officers (Messrs. Shaper, Kean and Listengart) voluntarily elected to take zero bonuses for work done in 2006. Our compensation committee agreed to the executives' request for zero bonuses, but wanted to make note that it was no reflection on any of the executives' personal performance for the year. It was also noted and reflected that each of our other executive officers' bonus was reduced in accordance with past practice and in light of making just one target. Mr. Parker's bonus was paid $500,000 from the plan according to the plan terms, and $350,000 from outside the plan as a discretionary bonus.

The plan was established, in part, to enable the portion of an officer's or other employee's annual bonus based on objective performance criteria to qualify as "qualified performance–based compensation" under the Internal Revenue Code. "Qualified performance–based compensation" is deductible by us for tax purposes. The tax deduction available with respect to compensation paid to executive officers is limited, unless the compensation qualifies as performance-based under the Internal Revenue Code. The requirements for performance-based compensation include the following:

- the compensation must be paid based solely on the attainment of objective performance measures established by a committee of outside directors, and

- the plan providing for such compensation must be approved by our stockholders.

The Annual Incentive Plan is a bonus plan that enables the portion of an officer or employee's annual bonus based on objective performance criteria to qualify as performance-based. Accordingly, that amount is deductible without regard to the deduction limit otherwise imposed by the Internal Revenue Code. If a bonus paid under the plan to an individual is in excess of the bonus opportunity set by the compensation committee, Section 162(m) of the Internal Revenue Code could limit the deductibility of the bonus paid. Consequently, the compensation committee set bonus opportunities under the plan for 2006 for the executive officers at dollar amounts in excess of that which were expected to actually be paid under the plan.

Our Board of Directors may amend the plan from time to time without stockholder approval except as required to satisfy the Internal Revenue Code or any applicable securities exchange rules. Awards may be granted under the plan for calendar years 2007 through 2009, unless the plan is terminated earlier by our Board. However, the plan will remain in effect until payment has been completed with respect to all awards granted under the plan prior to its termination.

Restricted Stock and Restricted Stock Unit Awards

This includes grants of restricted stock (or restricted stock units to our Canada-based executives) under our Amended and Restated 1999 Stock Plan, referred to in this report as the stock plan. The stock plan allows for grants of restricted stock, restricted stock units and non-qualified stock options. We believe the plan permits us to keep pace with changing developments in compensation and benefit programs, making us competitive with those companies that offer incentives to attract and retain employees.

The purposes of the stock plan are to:

- enable our employees and the employees of our subsidiaries to develop a sense of proprietorship and personal involvement in our financial success and the financial success of our subsidiaries; and
- encourage those employees to remain with and devote their best efforts to our business and the business of our subsidiaries.

Our officers and other employees and employees of other entities in which we have a direct or indirect interest are eligible to participate in the plan. Our compensation committee, which administers the plan, has the sole discretion to select participants from among eligible persons. Directors who are not employees are not eligible to participate in the plan. The aggregate number of shares of common stock which may be issued under the plan with respect to options, restricted stock and restricted stock units may not exceed 10,500,000, subject to adjustment for certain transactions affecting the common stock. Lapsed, forfeited or canceled options, and shares subject to forfeited restricted stock units, will not count against this limit and can be regranted under the plan. Options with respect to more than 1,000,000 shares of common stock, restricted stock with respect to more than 500,000 shares of common stock and restricted stock units with respect to more than 100,000 shares of common stock may not be granted to any one employee during any five year period. The shares issued under the plan may be issued from shares held in treasury or from authorized but unissued shares.

The stock plan provides for the grant of:

- nonqualified stock options;
- stock appreciation rights in tandem with stock options;
- restricted stock; and
- restricted stock units.

Awards may be granted individually, in combination, or in tandem as determined by our compensation committee. Our Board of Directors may amend the plan without stockholder approval, unless that approval is required by applicable law, rules, regulations or stock exchange requirements; however, our Board of Directors may not amend the plan in such a way that would impair the rights of a participant under an award without the consent of such participant, or that would decrease any authority granted to our compensation committee in contravention of Rule 16b-3 under the Securities Exchange Act of 1934, as amended. In addition, our Board of Directors may terminate the plan at any time.

Our compensation committee establishes the form and terms of each grant of restricted stock or restricted stock units, and each grant is evidenced by a written agreement. Shares of restricted stock and restricted stock units are subject to "forfeiture restrictions" that restrict the transferability of the shares or units and obligate the participant to forfeit and surrender the shares or units under certain circumstances, such as termination of employment. Our compensation committee may decide that forfeiture restrictions on restricted stock or restricted stock units will lapse upon the holder's continued employment for a specified period of time, the attainment of one or more performance targets established by our compensation committee, the occurrence of any event or the satisfaction of any condition specified by our compensation committee, or a combination of any of these. The performance targets may be based on:

- the price of a share of our common stock or of the equity of one of our subsidiaries or business units;
- our earnings per share or the earnings per share of one of our subsidiaries or business units;
- our total stockholder value or the total stockholder value of one of our subsidiaries or business units;
- our dividends or distributions or the dividends or distributions of one of our subsidiaries or business units;
- our revenues or the revenues of one of our subsidiaries or business units;
- our debt/equity ratio, interest coverage ratio or indebtedness/earnings before or after interest, taxes, depreciation and amortization ratio, or such ratios with respect to one of our subsidiaries or business units;
- our cash coverage ratio or the cash coverage ratio with respect to one of our subsidiaries or business units;

- our net income (before or after taxes) or the net income (before or after taxes) of one of our subsidiaries or business units;

- our cash flow or cash flow return on investments or the cash flow or cash flow return on investments of one of our subsidiaries or business units;

- our earnings before or after interest, taxes, depreciation, and/or amortization or earnings before or after interest, taxes, depreciation, and/or amortization of one of our subsidiaries or business units;

- our economic value added or the economic value added of one of our subsidiaries or business units;

- our return on stockholders' equity or the return on stockholders' equity of one of our subsidiaries or business units; or

- the payment of a bonus under the Annual Incentive Plan as a result of the attainment of performance goals based on one or more of the criteria set forth above.

Each grant of restricted stock or restricted stock units may have different forfeiture restrictions, in the discretion of our compensation committee. Our compensation committee may, in its sole discretion, prescribe additional terms, conditions or restrictions relating to restricted stock or restricted stock units, including, but not limited to, rules pertaining to the termination of employment (by retirement, disability, death or otherwise) of a participant prior to the lapse of the forfeiture restrictions, and terms related to tax matters.

Unless otherwise provided for in a written agreement, a participant will have the right to receive dividends with respect to restricted stock, to vote the stock and to enjoy all other stockholder rights, except that:

- the participant will not be entitled to delivery of the stock certificate unless and until the forfeiture restrictions have lapsed;

- we will retain custody of the stock unless and until the forfeiture restrictions have lapsed;

- the participant may not sell, transfer, pledge, exchange, hypothecate or otherwise dispose of the stock unless and until the forfeiture restrictions have lapsed; and

- a breach by a participant of the terms and conditions established by our compensation committee pursuant to the restricted stock agreement will cause a forfeiture of the restricted stock by the participant.

Upon the lapse of the forfeiture restrictions on restricted stock units, the participant is entitled to receive an amount equal to the product of (1) the number of restricted stock units with respect to which the forfeiture restrictions have lapsed, and (2) the fair market value per share of our common stock on the date the forfeiture restrictions lapse. Our compensation committee decides whether the participant receives this amount in shares of our common stock, cash, or a combination of cash and shares. The fair market value of our common stock generally is determined to be the closing sale price reported in *The Wall Street Journal* for the New York Stock Exchange-Composite Transactions.

Unless otherwise provided for in a written agreement, dividends payable with respect to restricted stock will be paid to a participant in cash on the day on which the corresponding dividend on shares is paid to our stockholders, or as soon as administratively feasible thereafter, but no later than the fifteenth day of the third calendar month following the day on which the corresponding dividend is paid to our stockholders. Our compensation committee may, in its sole discretion, decide that a participant's right to receive dividends on restricted stock is subject to the attainment of one or more performance targets based on the criteria listed above.

Our compensation committee may decide that a participant shall have the right to receive dividend equivalents with respect to restricted stock units. In such event, unless otherwise provided for in a written agreement, the dividend equivalents payable with respect to restricted stock units will be paid to a participant in cash on the day on which the corresponding dividend on shares is paid to stockholders, or as soon as administratively feasible thereafter, but no later than the fifteenth day of the third calendar month following the day on which the corresponding dividend is paid to stockholders. Our compensation committee may, in its sole discretion, decide that a participant's right to receive dividend equivalents on restricted stock units is subject to the attainment of one or more performance targets based on the criteria listed above.

Our compensation committee at any time may accelerate the time or conditions under which the forfeiture restrictions lapse. However, except in the event of a corporate change (as defined in the plan), our compensation committee may not take any such action with respect to "covered employees" (within the meaning of Treasury Regulation § 1.162-27(c)(2)) if such restricted stock or restricted stock units have been designed to meet the exception for performance-based compensation under

Section 162(m) of the Internal Revenue Code unless the performance targets with respect to the restricted stock or restricted stock units have been attained.

For the year ended December 31, 2006, no restricted stock or options to purchase shares of Kinder Morgan, Inc. were granted to any of our executive officers.

Other Compensation

Kinder Morgan Savings Plan. The Kinder Morgan Savings Plan is a defined contribution 401(k) plan. The plan permits all U.S.-based full-time employees of Kinder Morgan, Inc. and KMGP Services Company, Inc., including the U.S.-based named executive officers, to contribute between 1% and 50% of base compensation, on a pre-tax basis, into participant accounts. In addition to a mandatory contribution equal to 4% of base compensation per year for most plan participants, our general partner may make special discretionary contributions. Certain employees' contributions are based on collective bargaining agreements. The mandatory contributions are made each pay period on behalf of each eligible employee. All employer contributions, including discretionary contributions, are in the form of Kinder Morgan, Inc. common stock that is immediately convertible into other available investment vehicles at the employee's discretion. Participants may direct the investment of their contributions into a variety of investments. Plan assets are held and distributed pursuant to a trust agreement.

For employees hired on or prior to December 31, 2004, all contributions, together with earnings thereon, are immediately vested and not subject to forfeiture. Employer contributions for employees hired on or after January 1, 2005 will vest on the second anniversary of the date of hire. Effective October 1, 2005, for new employees of our Terminals business segment, a tiered employer contribution schedule was implemented. This tiered schedule provides for employer contributions of 1% for service less than one year, 2% for service between one and two years, 3% for service between two and five years, and 4% for service of five years or more. All employer contributions for employees of our Terminals business segment hired after October 1, 2005 will vest on the fifth anniversary of the date of hire.

At its July 2006 meeting, the compensation committee of our Board of Directors approved a special contribution of an additional 1% of base pay into the Savings Plan for each eligible employee. Each eligible employee will receive an additional 1% company contribution based on eligible base pay each pay period beginning with the first pay period of August 2006 and continuing through the last pay period of July 2007. The additional 1% contribution is in the form of Kinder Morgan, Inc. common stock (the same as the current 4% contribution) and does not change or otherwise impact the annual 4% contribution that eligible employees currently receive. It may be converted to any other Savings Plan investment fund at any time and it will vest according to the same vesting schedule described in the preceding paragraph. Since this additional 1% company contribution is discretionary, compensation committee approval will be required annually for each additional contribution. During the first quarter of 2007, excluding the 1% additional contribution described above, we will not make any additional discretionary contributions to individual accounts for 2006.

Additionally, in 2006, an option to make after-tax "Roth" contributions (Roth 401(k) option) to a separate participant account was added to the Savings Plan as an additional benefit to all participants. Unlike traditional 401(k) plans, where participant contributions are made with pre-tax dollars, earnings grow tax-deferred, and the withdrawals are treated as taxable income, Roth 401(k) contributions are made with after-tax dollars, earnings are tax-free, and the withdrawals are tax-free if they occur after both (i) the fifth year of participation in the Roth 401(k) option, and (ii) attainment of age 59 ½, death or disability. The employer contribution will still be considered taxable income at the time of withdrawal.

Cash Balance Retirement Plan. U.S.-based employees of KMGP Services Company, Inc. and Kinder Morgan, Inc., including the U.S.-based named executive officers, are also eligible to participate in a Cash Balance Retirement Plan. Certain employees continue to accrue benefits through a career-pay formula, "grandfathered" according to age and years of service on December 31, 2000, or collective bargaining arrangements. All other employees accrue benefits through a personal retirement account in the Cash Balance Retirement Plan. Under the plan, we make contributions on behalf of participating employees equal to 3% of eligible compensation every pay period. Interest is credited to the personal retirement accounts at the 30-year U.S. Treasury bond rate, or an approved substitute, in effect each year. Employees become fully vested in the plan after five years, and they may take a lump sum distribution upon termination of employment or retirement.

Canadian Pension Plan. Upon employment, our executive officers who are based in Canada become members of the Terasen Gas Inc. Retirement Plan for Management and Exempt Employees (the "Basic Plan"), a non-contributory pension plan. The pension benefit for executive officers under the Basic Plan equals 2% of the highest average earnings for such officer over 36 consecutive months of employment for each year of credited service, which is the accumulation of years and months of uninterrupted employment while a member of the Basic Plan to a maximum of 35 years. Normal retirement is the first day of the month coincident with or next following attainment of age 65. Executive officers who are members of the Basic Plan are eligible to retire at age 55 or age 50 if age plus service equal 65. If an executive officer is less than age 55, or age plus service is less than 80, the accrued pension to date of retirement is reduced 3% per year before age 60, otherwise no reduction applies.

The Terasen Gas Inc. Supplemental Retirement Plan (the "SRP") is designed to provide our Canada-based executive officers with the portion of the company's pension promise which cannot be paid from the Basic Plan because of limits imposed by the Canada Income Tax Act. As the executive officers are members of the Basic Plan, they are automatically members of the SRP. The SRP is secured with an irrevocable letter of credit which is renewed annually. The retirement pension payable under the SRP is equal to 2% of an executive officer's best three year average earnings for each year of credited service (to a maximum of 70%), adjusted to reflect the form of payment of the pension, less the pension provided under the Basic Plan. An executive officer can retire as early as age 55 with 2 years of service or age 50 if the sum of the executive officer's age and years of service equals 65 years. The executive officer's annual pension is not reduced if retirement occurs at or after age 60, or after the executive officer has attained age 55 if the executive officer's age plus years of service equal 80 years or more. If the executive officer does not qualify for unreduced retirement, the pension will be reduced by 3% per year for every year the executive officer's retirement date precedes the attainment of age 60. This reduction applies to the application of the Basic Plan pension offset (which is reduced in accordance with the Basic Plan provisions). However, different benefits may be provided under SRP or under other arrangements for individual participants or classes of participants as may be so designated from time to time.

On January 1, 2000, Terasen Gas Inc. implemented the defined contribution component of the Basic Plan and SRP. All executive officers were given a one-time option to remain in the defined benefit component or convert to the defined contribution component of the plans. All new executives who are hired on or after January 1, 2000 must, absent approval of the Board of Directors, join the defined contribution component. All contributions to the defined contribution component are made by Terasen Gas Inc.

The following table sets forth the estimated actuarial present value of each named executive officer's accumulated pension benefit as of December 31, 2006, under the provisions of the Kinder Morgan Cash Balance Retirement Plan or the Canadian Pension Plan, as applicable. Except as noted below, with respect to our executive officers, the benefits were computed using the same assumptions used for financial statement purposes, assuming current remuneration levels without any salary projection, and assuming participation until normal retirement at age 65. These benefits are subject to federal and state income taxes, where applicable, but are not subject to deduction for social security or other offset amounts.

Pension Benefits

Name	Plan Name	Current Credited Yrs of Service	Present Value of Accumulated Benefit[1]	Contributions During 2006
Richard D. Kinder..........	Cash Balance	6	$ -	$ -
Kimberly A. Dang..........	Cash Balance	5	24,114	6,968
David D. Kinder............	Cash Balance	6	32,114	7,337
Steven J. Kean...............	Cash Balance	5	33,957	7,422
Joseph Listengart...........	Cash Balance	6	42,885	7,835
Scott E. Parker...............	Cash Balance	8	62,385	8,735
C. Park Shaper...............	Cash Balance	6	42,885	7,835
R. L. (Randy) Jespersen.	Defined Benefit	17.7	C$1,371,700	C$207,000

[1] Except for Mr. Jespersen, the present values in the Pension Benefits table are based on certain assumptions-including a 6% discount rate, RP 2000 mortality (post-retirement only), 5% cash balance interest crediting rate, and lump sums calculated using a 5% interest rate and IRS mortality. We assumed benefits would commence at normal retirement date or unreduced retirement date, if earlier. No death or turnover was assumed prior to retirement date. For Mr. Jespersen, the present value is based on a retirement age of 60, a 5% discount rate, a 0% salary increase and 1994 mortality tables.

Other Potential Post-Employment Benefits. On October 7, 1999, Mr. Richard D. Kinder entered into an employment agreement with us pursuant to which he agreed to serve as our Chairman and Chief Executive Officer. His employment agreement provides for a term of three years and one year extensions on each anniversary of October 7th. Mr. Kinder, at his initiative, accepted an annual salary of $1 to demonstrate his belief in our long term viability. Mr. Kinder continues to accept an annual salary of $1, and he receives no other compensation. Mr. Kinder's employment agreement is extended annually at the request of our Board of Directors.

Our Board of Directors believes that Mr. Kinder's employment agreement contains provisions that are beneficial to us, our subsidiaries and our stockholders. For example, with limited exceptions, Mr. Kinder is prevented from competing in any manner with us or any of our subsidiaries, while he is employed by us and for 12 months following the termination of his employment with us. The agreement contains provisions that address termination with and without cause, termination as a result of change in duties or disability, and death. At his current compensation level, the maximum amount that would be paid to Mr. Kinder or his estate in the event of his termination is three times $750,000, or $2.25 million. This payment would be made if Mr. Kinder were terminated by us without cause or if Mr. Kinder terminated his employment with us as a result of change in duties (as defined in the employment agreement). There are no employment agreements or change-in-control arrangements with any of our other named executive officers, except for Mr. Jespersen as described below.

Terasen Gas Inc. has a written employment agreement with Mr. Jespersen that includes provisions with respect to the termination of his employment and a change in control of us. If the employment of Mr. Jespersen is terminated at any time other than for cause, we will pay a severance payment of: (i) an amount equivalent to two times his annual salary and two times his average bonus under the Annual Incentive Plan; (ii) an amount in lieu of all pension plan contributions and all other benefit contributions ordinarily paid by us for insured benefits equivalent to 30% of the total amount paid to him for annual salary and bonus under the Annual Incentive Plan, as described above; and (iii) an amount in respect of outplacement counseling equal to 10% of his annual salary. If his employment is terminated by us or by him for Good Reason (as defined in the agreement) within three months of a Change in Control (as defined in the agreement), we will pay a severance payment of: (i) an amount equivalent to two times his annual salary and two times his average bonus under the Annual Incentive Plan; (ii) an amount equivalent to two times the sum of all pension plan contributions and all other benefit contributions and premiums ordinarily paid by us for insured benefits, which would, but for the termination have been paid by us for his benefit; at his option, rather than payment of an amount equivalent to pension contributions, we will add an additional 24 months to his age and an additional 24 months to his service for the purpose of calculating the value of his pension benefit upon termination; and, (iii) an amount in respect of outplacement counseling equal to 10% of his annual salary. Pursuant to the agreement, for the purpose of calculating pension entitlement at the time of retirement, we will, subject to all applicable laws, credit him with two years of pensionable service per year of service up until June 30, 2009. If Mr. Jespersen retires between age 54 and 55, the pension entitlement will not be subject to any penalty related to early retirement that may apply pursuant to the relevant retirement plan in effect at the time of retirement. If Mr. Jespersen retires before age 54, the terms of the relevant retirement plan in effect at the time of retirement shall apply but, notwithstanding any contrary language that may appear in the relevant retirement plan, he will be eligible to participate in our retiree medical plan in place at the time of retirement.

Kinder Morgan Energy Partners Common Unit Option Plan. Pursuant to Kinder Morgan Energy Partners' Common Unit Option Plan, Kinder Morgan Energy Partners' and its affiliates' key personnel are eligible to receive grants of options to acquire Kinder Morgan Energy Partners common units. The total number of common units authorized under the plan is 500,000. None of the options granted under this plan may be "incentive stock options" under Section 422 of the Internal Revenue Code. If an option expires without being exercised, the number of common units covered by such option will be available for a future award. The exercise price for an option may not be less than the fair market value of a common unit on the date of grant. The compensation committee of Kinder Morgan Management's Board of Directors administers the unit option plan, and the plan has a termination date of March 5, 2008.

For the year ended December 31, 2006, no options to purchase common units were granted to or exercised by any of the named executive officers. Furthermore, as of December 31, 2006, none of the named executive officers owned unexercised common unit options.

Summary Compensation Table

The following table shows compensation paid by us for services rendered during fiscal year 2006 by (i) our principal executive officer, (ii) our principal financial officer, (iii) the three most highly compensated executive officers serving at fiscal year end, and (iv) our three other highest ranking executiv e officers (collectively referred to as the "named executive officers"):

Name and Principal Position	Year	Salary	Bonus	(1) Stock Awards	(2) Option Awards	(3) Non-Equity Incentive Plan Compensation	(4) Change in Pension Value	(5) All Other Compensation	Total
Richard D. Kinder................ Director, Chairman and Chief Executive Officer	2006	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ 1
Kimberly A. Dang................ Vice President and Chief Financial Officer	2006	200,000	-	139,296	37,023	270,000	6,968	46,253	699,540
Steven J. Kean...................... Executive Vice President and Chief Operating Officer	2006	200,000	-	1,591,192	147,943	-	7,422	284,919	2,231,476
David D. Kinder.................. Vice President Corporate Development and Treasurer	2006	200,000	-	235,207	63,586	315,000	7,337	164,630	985,760
Joseph Listengart................. Vice President, General Counsel and Secretary	2006	200,000	-	721,817	-	-	7,835	224,753	1,154,405
Scott E. Parker .... Vice President (President, Natural Gas Pipelines)	2006	200,000	350,000	881,317	29,490	500,000	8,735	164,630	2,134,172
C. Park Shaper...................... President	2006	200,000	-	1,134,283	24,952	-	7,835	348,542	1,715,612
R. L. (Randy) Jespersen........ President, Terasen Gas	2006	C$250,000	-	C$188,000	-	C$300,000	C$207,000	C$64,805	C$1,009,805

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[1] None of the restricted Kinder Morgan, Inc. stock (restricted stock units for Mr. Jespersen) awards were granted in 2006. Table amounts only represent the calendar year 2006 expense attributable to Kinder Morgan, Inc. restricted stock and restricted stock units awarded in 2003, 2004 and 2005, and these awards were reflected in compensation tables previously filed by us with the Securities and Exchange Commission. The restricted shares and restricted stock units were awarded according to the provisions of the Kinder Morgan, Inc. Stock Plan, and the computed value earned equaled the SFAS No. 123R expense accumulated during the 2006 calendar year. For grants of restricted stock, we take the value of the award at time of grant and accrue the expense over the vesting period according to SFAS No. 123R. For grants made July 16, 2003—KMI closing price was $53.80, twenty-five percent of the shares in each grant vest on the third anniversary after the date of grant and the remaining seventy-five percent of the shares in each grant vest on the fifth anniversary after the date of grant. For grants made July 20, 2004—KMI closing price was $60.79, fifty percent of the shares vest on the third anniversary after the date of grant and the remaining fifty percent of the shares vest on the fifth anniversary after the date of grant. For grants made July 20, 2005—KMI closing price was $89.48, twenty-five percent of the shares in each grant vest on the third anniversary after the date of grant and the remaining seventy-five percent of the shares in each grant vest on the fifth anniversary after the date of grant.

[2] None of the options to purchase our shares were granted in 2006. Table amounts only represent the calendar year 2006 expense attributable to options to purchase our shares granted in 2002 and 2003, and these awards were reflected in compensation tables previously filed by us with the Securities and Exchange Commission. The options were granted according to the provisions of the Stock Plan, and the co mputed value earned equaled the SFAS No. 123R expense accumulated on unvested options during the 2006 calendar year. For options granted in 2002—volatility of 0.3912 using a 6 year term, 4.01% five year risk free interest rate return, and a 0.71% expected annual dividend rate. For options granted in 2003—volatility of 0.3853 using a 6.25 year term, 3.37% treas ury strip quote at time of grant, and a 2.973% expected annual dividend rate.

[3] Represents amounts paid according to the provisions of the Annual Incentive Plan—except in the case of Mr. Parker, where

$500,000 was paid under the plan and $350,000 was paid outside of the plan. Amounts were earned in 2006 but paid in 2007.

4 For the U.S.-based executives, represents the 2006 change in the actuarial present value of accumulated defined pension benefit (including unvested benefits) according to the provisions of our Cash Balance Retirement Plan.

5 For the U.S.-based executives excluding Mr. Richard D. Kinder, amounts represent value of contributions to the Kinder Morgan Savings Plan (a 401(k) plan), value of group-term life insurance exceeding $50,000, taxable parking subsidy and dividends paid on unvested restricted stock awards. For each U.S.-based executive excluding Mr. Richard D. Kinder, amounts include $10,000 representing the value of contributions to the Kinder Morgan Savings Plan. Amounts representing the value of dividends paid on unvested restricted stock or restricted stock unit awards are as follows: for Ms. Dang $35,875; for Mr. Kean $273,000; for Mr. David D. Kinder $69,563; for Mr. Listengart $214,375; for Mr. Parker $154,000; for Mr. Shaper $336,875; and for Mr. Jespersen C$31,340. For Mr. Jespersen, amount includes $20,064 of unused benefits allowance for which he received a cash payment. For Mr. Jespersen, amount also includes C$587 of mortgage interest and C$12,814 of imputed interest on a C$250,000 interest free loan provided by Terasen prior to our acquisition of Terasen to assist in purchasing a residence for Mr. Jespersen. This loan was eliminated in 2006 and is no longer in place.

The following supplemental compensation table shows compensation details on the value of all non-guaranteed and non-discretionary incentive awards granted during 2006 to our named executive officers. The table includes grant awards made during 2006 and discloses estimated future payouts for both equity and non-equity incentive plans.

Grants of Plan-Based Awards

	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1]		
Name	**Threshold**	**Target**	**Maximum**
Richard D. Kinder	$ –	$ –	$ –
Kimberly A. Dang	500,000	1,000,000	1,500,000
Steven J. Kean	750,000	1,500,000	2,000,000
David D. Kinder	500,000	1,000,000	1,500,000
Joseph Listengart	500,000	1,000,000	1,500,000
Scott E. Parker	500,000	1,000,000	1,500,000
C. Park Shaper	750,000	1,500,000	2,000,000
R. L. (Randy) Jespersen	500,000	1,000,000	1,500,000

1 (Represents grants under the Annual Incentive Plan for 2006. See "Elements of Compensation—Possible Annual Cash Bonus (Non-Equity Cash Incentive)" for a discussion of these awards.

The following tables set forth certain information at December 31, 2006 with respect to all outstanding equity awards granted to our named executive officers.

Outstanding Equity Awards at 2006 Year-End

	Option Awards				Stock Awards	
	No. of Shares Underlying Unexercised Options					
Name	Exercisable	Unexercisable	Option Exercise Price	Option Expiration Date	No. of Shares that Have Not Vested[1]	Market Value of Shares that Have Not Vested[2]
Richard D. Kinder	–	–	$ –	–	–	$ –
Kimberly A. Dang	10,250	–	56.99	Jan. 16, 2012	8,000	846,000
	10,000	–	39.12	July 17, 2012		
	4,500	–	53.80	July 16, 2010		
Steven J. Kean	12,500	–	56.99	Jan. 16, 2012	78,000	8,248,500
	13,500	–	39.12	July 12, 2012		
	10,000	–	53.80	July 16, 2010		
David D. Kinder	12,500	–	49.875	Jan. 17, 2011	15,750	1,665,563
	100	–	49.875	Jan. 17, 2011		
	8,000	–	39.12	July 12, 2012		
Joseph Listengart	50,000	–	23.8125	Oct. 8, 2009	52,500	5,551,875
	6,300	–	49.875	Jan. 17, 2011		
Scott E. Parker	10,000	–	53.80	July 16, 2010	44,000	4,653,000
C. Park Shaper	95,000	–	24.75	Jan. 20, 2010	82,500	8,724,375
	25,000	–	49.875	Jan. 17, 2011		
	100,000	–	56.99	Jan. 16, 2012		
R. L. (Randy) Jespersen	–	–	–	–	6,000	634,500

[1] For Ms. Dang 2,000 shares vest July 20, 2007, 1,500 shares vest July 20, 2009, and 4,500 shares vest July 20, 2010; for Mr. Kean 4,000 shares vest July 20, 2007, 17,500 shares vest July 20, 2008, 4,000 shares vest July 20, 2009, and 52,500 shares vest July 20, 2010; for Mr. David D. Kinder 11,250 shares vest July 16, 2008, and 4,500 shares vest July 20, 2010; for Mr. Listengart 52,500 shares vest July 16, 2008; for Mr. Parker 4,000 shares vest July 20, 2007, 9,000 shares vest July 20, 2008, 4,000 shares vest July 20, 2009, and 27,000 shares vest July 20, 2010; for Mr. Shaper 82,500 shares vest July 16, 2008; for Mr. Jespersen 2,000 shares vest on the January 18 of each of 2007, 2008 and 2009. Upon closing of the proposed merger agreement providing for the acquisition of us by investors, including Mr. Richard D. Kinder and other senior members of our management, all restricted stock vesting dates would be accelerated.

[2] Calculated on the basis of the fair market value of the underlying shares at December 31, 2006 ($105.75).

The following tables set forth certain information for the fiscal year ended December 31, 2006 with respect to all outstanding equity awards vested to our named executive officers during 2006 and all exercises of stock options during 2006.

Option Exercises and Stock Vested in 2006

	Option Awards		Stock Awards	
Name	Shares Acquired on Exercise	Value Realized on Exercise[1]	Shares Acquired on Vesting	Value Realized on Vesting[2]
Richard D. Kinder	–	$ –	–	$ –
Kimberly A. Dang	–	–	–	–
Steven J. Kean	11,500	757,165	5,000	483,850
David D. Kinder	–	–	4,000	399,193
Joseph Listengart	–	–	20,000	1,991,925
Scott E. Parker	–	–	625	60,481
C. Park Shaper	–	–	30,000	2,991,925
R. L. (Randy) Jespersen	–	–	–	–

[1] Calculated on the basis of the fair market value of the underlying shares at exercise date, minus the exercise price.

[2] Calculated on the basis of the fair market value of underlying shares at the vesting date.

Director Compensation

Compensation Committee Interlocks and Insider Participation. Our compensation committee, comprised of Messrs. Ted A. Gardner, William J. Hybl, Edward Randall, III, James M. Stanford, and H. A. True, III, makes compensation decisions regarding our executive officers. Mr. Richard D. Kinder, Mr. James E. Street and Messrs. Shaper and Kean, who are our executive officers, participate in the deliberations of the compensation committee concerning executive officer compensation. None of the members of our compensation committee is or has been one of our officers or employees, and none of our executive officers served during 2006 on a board of directors of another entity which has employed any of the members of the compensation committee.

Directors Fees. Directors who are not also our employees participate in our Non-Employee Directors Stock Awards Plan, which was established in January 2005 and approved by our stockholders at our annual meeting of stockholders on May 10, 2005. The plan is administered by the compensation committee of our Board of Directors. The primary purpose of this plan is to promote our interests and the interests of our stockholders by aligning the compensation of the non-employee members of our Board of Directors with stockholders' interests. Directors who are also our employees (Mr. Richard D. Kinder) do not receive compensation in their capacity as directors.

Each of our non-employee directors is awarded, on an annual basis, restricted stock for his services, and each annual award is evidenced by an agreement between us and each non-employee director, which agreement contains the terms and conditions of each award. Pursuant to this agreement, all shares of our stock issued under this plan are subject to forfeiture restrictions. Until the forfeiture restrictions lapse, stock issued under the plan may not be sold, assigned, transferred, exchanged, or pledged by a non-employee director. In the event the director's service as one of our directors is terminated prior to the lapse of the forfeiture restriction either for cause, or voluntary resignation, such director shall, for no consideration, forfeit to us all stock to the extent then subject to the forfeiture restrictions. Stock with respect to which forfeiture restrictions have lapsed shall cease to be subject to any forfeiture restrictions, and we will provide each director a certificate representing the stock as to which the forfeiture restrictions have lapsed. In addition, each non-employee director shall have the right to receive dividends with respect to the stock awarded to him under the plan, to vote such stock and to enjoy all other stockholder rights, including during the period prior to the lapse of the forfeiture restrictions.

At our Board of Directors' compensation committee meeting in January 2006, it was determined that each of our non-employee directors would receive 1,600 restricted shares of our common stock, the restrictions on which lapsed on July 17, 2006, the sixth-month anniversary of such meeting.

Further, at our Board of Directors' compensation committee meeting in January 2006, it was determined that the directors would not, generally, receive a cash retainer for their services to the Board for 2006; however, it was approved that each member of the Audit Committee would receive $5,000 for 2006, the Chairman of the audit committee would receive an additional $10,000 for 2006, the Chairman of the compensation committee would receive $10,000 for 2006, and the Lead Director would receive $20,000 for 2006. All of the foregoing was paid in quarterly installments during 2006.

All directors are reimbursed for reasonable travel and other expenses incurred in attending all Board and/or committee meetings.

Our Board of Directors has established a policy pursuant to which each of our directors must own at least 10,000 shares of our common stock. The directors will have six years from the date our Board established the policy, or, if later, the date they were elected to the Board to accumulate the 10,000 share position.

The following table discloses the compensation earned by each of our non-employee directors for Board service during 2006.

Non-Employee Director Compensation for Fiscal Year 2006

Name	Fees Earned or Paid in Cash	Restricted Stock Awards[1]	All Other Compensation[2]	Total
Edward H. Austin	$ 5,000	$156,000	$ 2,800	$163,800
Charles W. Battey	5,000	156,000	2,800	163,800
Stewart A. Bliss	30,000	156,000	2,800	188,800
Ted A. Gardner	10,000	156,000	2,800	168,800
William J. Hybl	-	156,000	2,800	158,800
Michael C. Morgan	-	156,000	2,800	158,800
Edward Randall, III	-	156,000	2,800	158,800
James M. Stanford	-	156,000	2,800	158,800
Fayez Sarofim	2,500	156,000	2,800	161,300
H. A. True, III	-	156,000	2,800	158,800
Douglas W.G. Whitehead	3,750	156,000	2,800	162,550

[1] Represents the value of restricted stock awarded in 2006 according to the provisions of our Non-Employee Directors Stock Awards Plan. Value computed as the number of shares of restricted stock awarded (1,600) times the closing price of our stock on the date of award ($97.50 at January 17, 2006).

[2] Represents the value of restricted stock dividends for the first and second quarters of 2006.

Compensation Committee Report

Throughout fiscal 2006, the compensation committee of our Board of Directors was comprised of four directors (in addition to its chairman), each of which our Board of Directors has determined meets the criteria for independence under our governance guidelines and the New York Stock Exchange rules.

The compensation committee has discussed and reviewed the above Compensation Discussion and Analysis for fiscal year 2006 with management. Based on this review and discussion, the compensation committee recommended to our Board of Directors that this Compensation Discussion and Analysis be included in this annual report on Form 10-K for the fiscal year 2006.

Compensation Committee:
Ted A. Gardner, Chairman
William J. Hybl
Edward Randall, III
James M. Stanford
H. A. True, III

Item 12. ***Security Ownership of Certain Beneficial Owners and Management***

The following table sets forth information as of January 31, 2007 with respect to the beneficial ownership of our common stock by each of our directors, each of our named executive officers identified in Item 11, all of our directors and executive officers as a group and each person who is known to us to beneficially own more than 5% of our common stock.

Unless otherwise indicated, the address of each person named in the table below is c/o Kinder Morgan, Inc., 500 Dallas Street, Suite 1000, Houston, Texas 77002, and each beneficial owner named in the table has sole voting and sole investment power with respect to all shares beneficially owned. The percentage listed in the column entitled "Percentage of Class" is calculated based on 134,188,793 shares of our common stock outstanding on January 31, 2007. This number excludes 15,023,351 shares held in treasury. The amounts and percentage of common stock beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities and a person may be deemed to be a beneficial owner of securities as to which such person has no economic interest.

Beneficial Owner	Shares Beneficially Owned	Percentage Of Class
Richard D. Kinder [1]	24,000,000	17.9%
Edward H. Austin [2]	279,755	*
Charles W. Battey [3]	57,850	*
Stewart A. Bliss [4]	52,525	*
Ted A. Gardner [5]	263,350	*
William J. Hybl [6]	69,304	*
Michael C. Morgan [7]	242,468	*
Edward Randall, III [8]	187,650	*
Fayez Sarofim [9]	2,166,497	1.6%
James M. Stanford	1,688	*
H. A. True, III [10]	40,350	*
Douglas W.G. Whitehead	5,221	*
Kimberly A. Dang [11]	33,915	*
Steven J. Kean [12]	124,754	*
David D. Kinder [13]	42,307	*
Joseph Listengart [14]	140,368	*
Scott E. Parker [15]	55,431	*
C. Park Shaper [16]	352,070	*
R. L. Randy Jespersen	7,883	*
All directors and executive officers as a group (22 persons) [17]	28,261,116	21.07%

* Less than 1%

[1] Includes (i) 5,173 shares held by Mr. Kinder's wife and (ii) 250 shares held by Mr. Kinder in a custodial account for his nephew. Mr. Kinder disclaims any and all beneficial or pecuniary interest in these shares.

[2] Mr. Austin may be deemed to be the beneficial owner of 279,755 shares of our common stock. Of these shares, Mr. Austin has sole voting and investment power with respect to 94,857 shares which are owned directly of record and beneficially by him and he may be deemed to have shared voting and investment power as to 144,898 shares of our common stock. Of the shares which are not subject to sole voting and investment power, 115,873 shares are held in a family limited partnership of which Mr. Austin is a general and limited partner and 29,025 shares are held in investment advisory accounts managed and/or monitored by Mr. Austin. Includes options to purchase 40,000 shares currently exercisable or exercisable within 60 days of January 31, 2007.

[3] Includes options to purchase 46,500 shares currently exercisable or exercisable within 60 days of January 31, 2007.

[4] Includes options to purchase 44,500 shares currently exercisable or exercisable within 60 days of January 31, 2007.

[5] Includes options to purchase 40,000 shares currently exercisable or exercisable within 60 days of January 31, 2007.

[6] Includes (i) options to purchase 52,500 shares currently exercisable or exercisable within 60 days of January 31, 2007 and (ii) 600 shares owned by Mr. Hybl's spouse.

[7] Includes (i) options to purchase 5,000 shares currently exercisable or exercisable within 60 days of January 31, 2007, (ii) 15,000 restricted shares and (iii) 211,753 shares held in the Michael C. Morgan and Christine R. Morgan 2001 Investment Trust, a trust in which Mr. Morgan is both a beneficiary and a trustee.

[8] Mr. Randall may be deemed to be the beneficial owner of 197,650 shares of our common stock. Of these shares, Mr. Randall has sole voting and investment power with respect to 113,350 shares which are owned directly of record and beneficially by him and 27,300 shares are held in trusts of which Mr. Randall is trustee and to which he shares voting and investment power but has no beneficial interest. Includes options to purchase 57,000 shares currently exercisable or exercisable within 60 days of January 31, 2007.

[9] Mr. Sarofim may be deemed to be the beneficial owner of 2,166,497 shares of our common stock. Of these shares, Mr. Sarofim has sole voting and investment power with respect to 1,549,950 shares, which are owned of record and beneficially by him, and may be deemed to have shared voting power as to 320,092 shares of our common stock and shared disposition power as to 614,947 shares of our common stock. Of the securities which are not subject to sole voting and investment power, 446,396 shares are held in investment advisory accounts managed by Fayez Sarofim & Co. for numerous clients, 160,251 shares are held by Sarofim International Management Company for its own account, 4,300 shares are held in investment advisory accounts managed by Sarofim International Management Company, and 4,000 shares are held in investment advisory accounts managed by Sarofim Trust Co. Fayez Sarofim & Co. is an Investment Adviser registered under the Investment Advisers Act of 1940, of which Mr. Sarofim is Chairman of the Board, President, and, through a holding company, majority stockholder. Sarofim International Management Company and Sarofim Trust Co. are wholly owned subsidiaries of Fayez Sarofim & Co. Additionally, 1,600 shares are held in trusts of which Mr. Sarofim is trustee, as to which he shares voting and investment power but has no beneficial interest.

[10] Includes 225 shares held by Mr. True in a nominee account.

[11] Includes (i) options to purchase 24,750 shares currently exercisable or exercisable within 60 days of January 31, 2007 and (ii) 8,000 restricted shares.

[12] Includes (i) options to purchase 36,000 shares currently exercisable or exercisable within 60 days of January 31, 2007 and (ii) 78,000 restricted shares.

[13] Includes (i) options to purchase 20,600 shares currently exercisable or exercisable within 60 days of January 31, 2007 and (ii) 15,750 restricted shares.

[14] Includes (i) options to purchase 56,300 shares currently exercisable or exercisable within 60 days of January 31, 2007 and (ii) 52,500 restricted shares.

[15] Includes (i) options to purchase 10,000 shares currently exercisable or exercisable within 60 days of January 31, 2007 and (ii) 44,000 restricted shares.

[16] Includes (i) options to purchase 220,000 shares currently exercisable or exercisable within 60 days of January 31, 2007 and (ii) 82,500 restricted shares.

[17] Includes (i) options to purchase 691,500 shares exercisable within 60 days of January 31, 2007 and (ii) 340,750 restricted shares.

Equity Compensation Plan Information

The following table sets forth information regarding our equity compensation plans as of December 31, 2006. Specifically, the table provides information as of December 31, 2006 regarding our 1994 Long-Term Incentive Plan (under which no further awards are to be made since March 24, 2004, but under which there remain shares of our common stock to be issued upon the exercising of options to purchase our common stock previously awarded under the plan), our 1992 Stock Option Plan for Non-Employee Directors, as amended (under which no further awards are to be made since May 10, 2005, but under which there remain shares of our common stock to be issued upon the exercising of options to purchase our common stock previously awarded under the plan), our Employees Stock Purchase Plan, our Foreign Subsidiary Employee Stock Purchase Plan, our Amended and Restated 1999 Stock Awards Plan and our Non-Employee Directors Stock Awards Plan.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity Compensation Plans Approved by Security Holders	2,336,517	$ 51.27	3,019,493
Equity Compensation Plans Not Approved by Security Holders	-	-	-
Total	2,336,517	$ 51.27	4,501,270 [1]

[1] Includes 1,481,777 shares available for future issuance under our Employees Stock Purchase Plan and our Foreign Subsidiary Employees Stock Purchase Plan, in which our executive officers do not participate.

Item 13. *Certain Relationships and Related Transactions, and Director Independence.*

Related Transactions

On August 28, 2006, we entered into a definitive merger agreement under which investors, including among others our Chairman and Chief Executive Officer, other senior members of our management, co-founder Bill Morgan, and current board members Fayez Sarofim and Mike Morgan, would acquire all of our outstanding common stock (except for shares held by certain stockholders and investors). For further information regarding this transaction, see "(A) General Development of Business" within Items 1 and 2 of this report. For information regarding other related transactions, see the discussion under "Other" within Items 1 and 2 of this report and Note 5 of the accompanying Notes to Consolidated Financial Statements.

Except for transactions through our Retail segment, our employees must obtain authorization from the appropriate business unit president of the relevant company or head of corporate function; and directors, business unit presidents, executive officers and heads of corporate functions must obtain authorization from the non-interested members of the audit committee of the applicable board of directors for any business relationship or proposed business transaction in which they or an immediate family member has a direct or indirect interest, or from which they or an immediate family member may derive a personal benefit (a "related party transaction"). The maximum dollar amount of related party transactions that may be approved as described above in this paragraph in any calendar year will be $1.0 million. Any related party transactions that would bring the total value of such transactions to greater than $1.0 million will be referred to the audit committee of the appropriate board of directors for approval or to determine the procedure for approval.

Director Independence

Our Board of Directors has adopted governance guidelines for the Board and charters for the audit committee, nominating and governance committee and compensation committee. The governance guidelines and the rules of the New York Stock Exchange require that a majority of our directors be independent, as described in those guidelines and rules. To assist in making determinations of independence, the Board has determined that the following categories of relationships are not material relationships that would cause the affected director not to be independent:

- If the director was an employee, or had an immediate family member who was an executive officer of Kinder Morgan Management, Kinder Morgan Energy Partners or us or any of their or our affiliates, but the employment relationship ended more than three years prior to the date of determination (or, in the case of employment of a director as an interim chairman, interim chief executive officer or interim executive officer, such employment relationship ended by the date of determination);
- If during any twelve month period within the three years prior to the determination the director received no more than, and has no immediate family member that received more than, $100,000 in direct compensation from us or our affiliates, other than (i) director and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service), (ii) compensation received by a director for former service as an interim chairman, interim chief executive officer or interim executive officer,

- and (iii) compensation received by an immediate family member for service as an employee (other than an executive officer);

- If the director is a current employee, or has an immediate family member that is a current executive officer, of another company that has made payments to, or received payments from, us and our affiliates for property or services in an amount which, in each of the three fiscal years prior to the date of determination, was less than the greater of $1.0 million or 2% of such other company's annual consolidated gross revenues. Contributions to tax-exempt organizations are not considered payments for purposes of this determination;

- If the director is also a director, but is not an employee or executive officer, of Kinder Morgan G.P., Inc. or another affiliate of Kinder Morgan Management or us, so long as such director is otherwise independent; and

- If the director beneficially owns less than 10% of each class of voting securities Kinder Morgan G.P., Inc., Kinder Morgan Management or us.

Our Board has affirmatively determined that Messrs. Austin, Battey, Bliss, Gardner, Hybl, Randall, Stanford, True and Whitehead, who constitute a majority of our directors, are independent as described in our governance guidelines and the New York Stock Exchange rules. Each of them meets the standards above and has no other relationship with us. In conjunction with regular quarterly Board meetings, these non-management directors also meet in executive session without members of management. Mr. Bliss was re-elected in the first quarter of 2006 for a one-year term to serve as lead director to develop the agendas for and preside at these executive sessions.

The governance guidelines and our audit committee charter, as well as the rules of the New York Stock Exchange and the Securities and Exchange Commission, require that members of the audit committee satisfy independence requirements in addition to those above. Our Board has determined that all of the members of the audit committee are independent as described under the relevant standards.

Item 14. ***Principal Accounting Fees and Services.***

The following sets forth fees billed for the audit and other services provided by PricewaterhouseCoopers LLP for the fiscal years ended December 31, 2006 and 2005 (in dollars):

	Year Ended December 31,	
	2006	2005
Audit fees[1]	$ 4,126,700	$ 2,036,500
Audit-Related fees[2]	–	123,000
Tax fees[3]	1,994,650	166,394
Total	$ 6,121,350	$ 2,325,894

[1] Includes fees for integrated audit of annual financial statements and internal control over financial reporting, reviews of the related quarterly financial statements, and reviews of documents filed with the Securities and Exchange Commission.

[2] Includes fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements.

[3] Includes fees related to professional services for tax compliance, tax advice and tax planning, consisting of tax services relating to the review or preparation of federal, state, local or foreign income. For 2006, amount includes fees of $1,356,399 billed to Kinder Morgan Energy Partners for professional services rendered for tax processing and preparation of Forms K-1 for unitholders.

All services rendered by PricewaterhouseCoopers LLP are permissible under applicable laws and regulations, and were pre-approved by our Audit Committee, consistent with the Audit Committee's charter, which requires the pre-approval of all audit and non-audit services. The Audit Committee's primary purposes include the following:

- monitor the integrity of our financial statements, financial reporting processes, systems of internal controls regarding finance, accounting and legal compliance and disclosure controls and procedures;

- monitor our compliance with legal and regulatory requirements;

- select, appoint, engage, oversee, retain, evaluate and terminate our external auditors, pre-approve all audit and non-audit services to be provided, consistent with all applicable laws, to us by our external auditors, and establish the fees and other compensation to be paid to our external auditors;

- monitor and evaluate the qualifications, independence and performance of our external auditors and internal auditing function; and

- establish procedures for the receipt, retention, response to and treatment of complaints, including confidential, anonymous submissions by our employees, regarding accounting, internal controls, disclosure or auditing matters, and provide an avenue of communication among our external auditors, management, the internal auditing function and our Board of Directors.

The Audit Committee has reviewed the external auditors' fees for audit and non-audit services for fiscal year 2006. The Audit Committee considered whether such non-audit services are compatible with maintaining the external auditors' independence and has concluded that they are compatible at this time.

Furthermore, the Audit Committee will review the external auditors' proposed audit scope and approach as well as the performance of the external auditors. It also has direct responsibility for and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, will regularly review with the external auditors any problems or difficulties the auditors encountered in the course of their audit work, and will, at least annually, use its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items):

- the auditors' internal quality-control procedures;

- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;

- the independence of the external auditors; and

- the aggregate fees billed by our external auditors for each of the previous two fiscal years.

PART IV

Item 15. *Exhibits and Financial Statement Schedules.*

(a) (1) *Financial Statements*

Reference is made to the index of financial statements and supplementary data under Item 8 in Part II.

(2) *Financial Statement Schedules*

Schedule II - Valuation and Qualifying Accounts is omitted because the required information is shown in Note 1(G) of the accompanying Notes to Consolidated Financial Statements.

The financial statements, including the notes thereto, of Kinder Morgan Energy Partners, an equity method investee of the Registrant, are incorporated herein by reference to pages 134 through 240 of Kinder Morgan Energy Partners' Annual Report on Form 10-K for the year ended December 31, 2006.

(3) *Exhibits*

Any reference made to K N Energy, Inc. in the exhibit listing that follows is a reference to the former name of Kinder Morgan, Inc., a Kansas corporation and the registrant, and is made because the exhibit being listed and incorporated by reference was originally filed before October 7, 1999, the date of the change in the Registrant's name.

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of July 8, 1999, by and among K N Energy, Inc., Rockies Merger Corp., and Kinder Morgan, Inc., (Annex A-1 of K N Energy, Inc.'s Registration Statement on Form S-4 (File No. 333-85747))
2.2	First Amendment to Agreement and Plan of Merger, dated as of August 20, 1999, by and among K N Energy, Inc., Rockies Merger Corp., and Kinder Morgan, Inc., (Annex A-2 of K N Energy, Inc.'s Registration Statement on Form S-4 (File No. 333-85747))
2.3	Contribution Agreement, dated as of December 30, 1999, by and among Kinder Morgan, Inc., Natural Gas Pipeline Company of America, K N Gas Gathering, Inc., Kinder Morgan G.P., Inc. and Kinder Morgan Energy Partners, L.P. (Exhibit 99.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on January 14, 2000)
2.4	Combination Agreement, dated as of August 1, 2005, by and among Kinder Morgan, Inc., 0731297 B.C. Ltd. And Terasen Inc. (Exhibit 1.01 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on August 1, 2005)
2.5	Agreement and Plan of Merger dated August 28, 2006, among Kinder Morgan, Inc., Knight Holdco LLC and Knight Acquisition Co. (Exhibit 2.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on August 28, 2006)
3.1	Amended and Restated Articles of Incorporation of Kinder Morgan, Inc. and amendments thereto (Exhibit 3.1 to Kinder Morgan, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005)
3.2	Certificate of Designation of Kinder Morgan, Inc. Pursuant to Section 17-6401(g) of the Kansas General Corporation Code (Exhibit 3.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on October 25, 2005)
3.3	By-Laws of Kinder Morgan, Inc., as amended to January 18, 2006 (Exhibit 3.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on January 24, 2006)
4.1	Indenture dated as of September 1, 1988, between K N Energy, Inc. and Continental Illinois National Bank and Trust Company of Chicago (Exhibit 4(a) to Kinder Morgan, Inc.'s Annual Report on Form 10-K/A, Amendment No. 1 filed on May 22, 2000)

Exhibit Number	Description
4.2	First supplemental indenture dated as of January 15, 1992, between K N Energy, Inc. and Continental Illinois National Bank and Trust Company of Chicago (Exhibit 4.2 to the Registration Statement on Form S-3 (File No. 33-45091) of K N Energy, Inc. filed on January 17, 1992)
4.3	Second supplemental indenture dated as of December 15, 1992, between K N Energy, Inc. and Continental Bank, National Association (Exhibit 4(c) to Kinder Morgan, Inc.'s Annual Report on Form 10-K/A, Amendment No. 1 filed on May 22, 2000)
4.4	Indenture dated as of November 20, 1993, between K N Energy, Inc. and Continental Bank, National Association (Exhibit 4.1 to the Registration Statement on Form S-3 (File No. 33-51115) of K N Energy, Inc. filed on November 19, 1993)
4.5	Registration Rights Agreement among Kinder Morgan Management, LLC, Kinder Morgan Energy Partners, L.P. and Kinder Morgan, Inc. dated May 18, 2001 (Exhibit 4.7 to Kinder Morgan, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2002)
4.6	Rights Agreement between K N Energy, Inc. and the Bank of New York, as Rights Agent, dated as of August 21, 1995 (Exhibit 1 on Form 8-A dated August 21, 1995 (File No. 1-6446))
4.7	Amendment No. 1 to Rights Agreement between K N Energy, Inc. and the Bank of New York, as Rights Agent, dated as of September 8, 1998 (Exhibit 10(cc) to K N Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-6446))
4.8	Amendment No. 2 to Rights Agreement of Kinder Morgan, Inc. dated July 8, 1999, between Kinder Morgan, Inc. and First Chicago Trust Company of New York, as successor-in-interest to the Bank of New York, as Rights Agent (Exhibit 4.1 to Kinder Morgan, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 1999)
4.9	Form of Amendment No. 3 to Rights Agreement of Kinder Morgan, Inc. dated September 1, 2001, between Kinder Morgan, Inc. and First Chicago Trust Company of New York, as Rights Agent (Exhibit 4(m) to Kinder Morgan, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2001)
4.10	Form of Indenture dated as of August 27, 2002 between Kinder Morgan, Inc. and Wachovia Bank, National Association, as Trustee (Exhibit 4.1 to Kinder Morgan, Inc.'s Registration Statement on Form S-4 (File No. 333-100338) filed on October 4, 2002)
4.11	Form of First Supplemental Indenture dated as of December 6, 2002 between Kinder Morgan, Inc. and Wachovia Bank, National Association, as Trustee (Exhibit 4.2 to Kinder Morgan, Inc.'s Registration Statement on Form S-4 (File No. 333-102873) filed on January 31, 2003)
4.12	Form of 6.50% Note (contained in the Indenture incorporated by reference to Exhibit 4.12 hereto)
4.13	Form of Registration Rights Agreement dated as of December 6, 2002 among Kinder Morgan, Inc., Wachovia Securities, Inc., and Barclays Capital Inc. (Exhibit 4.4 to Kinder Morgan, Inc.'s Registration Statement on Form S-4 (File No. 333-102873) filed on January 31, 2003)
4.14	Form of certificate representing the common stock of Kinder Morgan, Inc. (Exhibit 4.1 to Kinder Morgan, Inc.'s Registration Statement on Form S-3 (File No. 333-102963) filed on February 4, 2003)
4.15	Form of Senior Indenture between Kinder Morgan, Inc. and Wachovia Bank, National Association, as Trustee (Exhibit 4.2 to Kinder Morgan, Inc.'s Registration Statement on Form S-3 (File No. 333-102963) filed on February 4, 2003)

Exhibit Number	Description
4.16	Form of Senior Note of Kinder Morgan, Inc. (included in the Form of Senior Indenture incorporated by reference to Exhibit 4.16 hereto)
4.17	Form of Subordinated Indenture between Kinder Morgan, Inc. and Wachovia Bank, National Association, as Trustee (Exhibit 4.4 to Kinder Morgan, Inc.'s Registration Statement on Form S-3 (File No. 333-102963) filed on February 4, 2003)
4.18	Form of Subordinated Note of Kinder Morgan, Inc. (included in the Form of Subordinated Indenture incorporated by reference to Exhibit 4.18 hereto)
4.19	Indenture dated as of December 9, 2005, among Kinder Morgan Finance Company, ULC, Kinder Morgan, Inc. and Wachovia Bank, National Association, as Trustee (Exhibit 4.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on December 15, 2005)
4.20	Form of notes (included in the Indenture filed as Exhibit 4.19 hereto)
4.21	Certain instruments with respect to the long-term debt of Kinder Morgan, Inc. and its consolidated subsidiaries that relate to debt that does not exceed 10% of the total assets of Kinder Morgan, Inc. and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K, 17 C.F.R. sec.229.601. Kinder Morgan, Inc. hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.
10.1	1994 Amended and Restated Kinder Morgan, Inc. Long-term Incentive Plan (Appendix A to Kinder Morgan, Inc.'s 2000 Proxy Statement on Schedule 14A)
10.2	Kinder Morgan, Inc. Amended and Restated 1999 Stock Plan (Appendix B to Kinder Morgan, Inc.'s 2004 Proxy Statement on Schedule 14A)
10.3	Kinder Morgan, Inc. Amended and Restated 1992 Stock Option Plan for Nonemployee Directors (Appendix A to Kinder Morgan, Inc.'s 2001 Proxy Statement on Schedule 14A)
10.4	2000 Annual Incentive Plan of Kinder Morgan, Inc. (Appendix D to Kinder Morgan, Inc.'s 2000 Proxy Statement on Schedule 14A)
10.5	Kinder Morgan, Inc. Employees Stock Purchase Plan (Appendix E to Kinder Morgan, Inc.'s 2000 Proxy Statement on Schedule 14A)
10.6	Form of Nonqualified Stock Option Agreement (Exhibit 10(f) to Kinder Morgan, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2000)
10.7	Form of Restricted Stock Agreement (Exhibit 10(g) to Kinder Morgan, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2000)
10.8	Directors and Executives Deferred Compensation Plan effective January 1, 1998 for executive officers and directors of K N Energy, Inc. (Exhibit 10(aa) to K N Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 1998 (File No. 1-6446))
10.9	Employment Agreement dated October 7, 1999, between the Company and Richard D. Kinder (Exhibit 99.D of the Schedule 13D filed by Mr. Kinder on November 16, 1999)
10.10	Form of Purchase Provisions between Kinder Morgan Management, LLC and Kinder Morgan, Inc. (included as Annex B to the Second Amended and Restated Limited Liability Company Agreement of Kinder Morgan Management, LLC filed as Exhibit 4.2 to Kinder Morgan Management, LLC's Registration Statement on Form 8-A/A filed on July 24, 2002)
10.11	Resignation and Non-Compete Agreement, dated as of July 21, 2004, between KMGP Services, Inc. and Michael C. Morgan (Exhibit 10.12 to Kinder Morgan, Inc.'s Form 10-Q for the quarter ended June 30, 2004)

Exhibit Number	**Description**
10.12	Credit Agreement, dated as of August 5, 2005, by and among Kinder Morgan, Inc., the lenders party thereto, Citibank, N.A., as Administrative Agent and Swingline Lender, Wachovia Bank, National Association and JPMorgan Chase Bank, N.A., as Co-Syndication Agents and The Bank of Tokyo-Mitsubishi, Ltd. and Suntrust Bank, as Co-Documentation Agents (Exhibit 10.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K, filed on August 11, 2005)
10.13	Amendment Number 1 to Credit Agreement, dated as of August 5, 2005, by and among Kinder Morgan, Inc., the lenders party thereto, Citibank, N.A., as Administrative Agent and Swingline Lender, Wachovia Bank, National Association and JPMorgan Chase Bank, N.A., as Co-Syndication Agents and The Bank of Tokyo-Mitsubishi, Ltd. and Suntrust Bank, as Co-Documentation Agents (Exhibit 10.2 to Kinder Morgan, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2005)
10.14	Kinder Morgan, Inc. Non-Employee Directors Stock Awards Plan (Exhibit 10.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on May 13, 2005)
10.15	Form of Restricted Stock Agreement (Exhibit 10.2 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on May 13, 2005)
10.16	Form of Nonqualified Stock Option Agreement (Exhibit 10.3 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on May 13, 2005)
10.17	364-Day Credit Agreement dated as of November 23, 2005, by and among 1197774 Alberta ULC, as Borrower, Kinder Morgan, Inc., as Guarantor, the lenders party thereto, and Citibank, N.A., Canadian Branch, as Administrative Agent (Exhibit 10.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on November 30, 2005)
10.18	Form of 2005 Credit Agreement dated as of January 13, 2006 among Terasen Gas (Vancouver Island) Inc., the lenders party thereto and RBC Capital Markets as Lead Arranger and Book Runner (Exhibit 10.2 to Kinder Morgan, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2006)
10.19	Kinder Morgan, Inc. Amended and Restated 1999 Stock Plan (Appendix A to Kinder Morgan, Inc.'s 2006 Proxy Statement on Schedule 14A filed on April 3, 2006)
10.20	Kinder Morgan, Inc. Foreign Subsidiary Employees Stock Purchase Plan (Appendix B to Kinder Morgan, Inc.'s 2006 Proxy Statement on Schedule 14A filed on April 3, 2006)
10.21	First Amendment to the Kinder Morgan, Inc. Employees Stock Purchase Plan (Appendix C to Kinder Morgan, Inc.'s 2006 Proxy Statement on Schedule 14A filed on April 3, 2006)
10.22	Form of Credit Agreement, dated as of May 5, 2006, by and among Terasen Inc., the lenders party thereto and The Toronto-Dominion Bank, as Administrative Agent (Exhibit 10.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on May 15, 2006)
10.23	Form of Indemnification Agreement between Kinder Morgan, Inc. and each member of the Special Committee of the Board of Directors (Exhibit 10.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on June 16, 2006)
10.24	Form of Credit Agreement, dated as of June 21, 2006, by and among Terasen Gas Inc.; Canadian Imperial Bank of Commerce, as Administrative Agent, Lead Arranger and Sole Bookrunner; The Bank of Nova Scotia, as Syndication Agent; and the other lenders identified in the Credit Agreement (Exhibit 10.1 to Kinder Morgan, Inc.'s Current Report on Form 8-K filed on June 27, 2006)
10.25*	Employment Agreement dated November 28, 2005, between Terasen Gas Inc. and Randall Jespersen
12.1*	Statement re: computation of ratio of earnings to fixed charges

Exhibit Number	**Description**
21.1*	Subsidiaries of the Registrant
23.1*	Consent of PricewaterhouseCoopers LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1	The financial statements of Kinder Morgan Energy Partners, L.P. and subsidiaries (incorporated by reference to pages 134 through 240 of the Annual Report on Form 10-K of Kinder Morgan Energy Partners, L.P. for the year ended December 31, 2006)

*Filed herewith.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

KINDER MORGAN, INC.
(Registrant)
By /s/ Kimberly A. Dang
Kimberly A. Dang
Vice President and Chief Financial Officer

Date: March 1, 2007

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities set forth below and as of the date set forth above.

/s/ Edward H. Austin, Jr. Edward H. Austin, Jr.	Director
/s/ Charles W. Battey Charles W. Battey	Director
/s/ Stewart A. Bliss Stewart A. Bliss	Director
/s/ Kimberly A. Dang Kimberly A. Dang	Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)
/s/ Ted A. Gardner Ted A. Gardner	Director
/s/ William J. Hybl William J. Hybl	Director
/s/ Richard D. Kinder Richard D. Kinder	Director, Chairman and Chief Executive Officer (Principal Executive Officer)
/s/ Michael C. Morgan Michael C. Morgan	Director
/s/ Edward Randall, III Edward Randall, III	Director
/s/ Fayez Sarofim Fayez Sarofim	Director
/s/ James M. Stanford James M. Stanford	Director
/s/ H. A. True, III H. A. True, III	Director
/s/ Douglas W. G. Whitehead Douglas W. G. Whitehead	Director