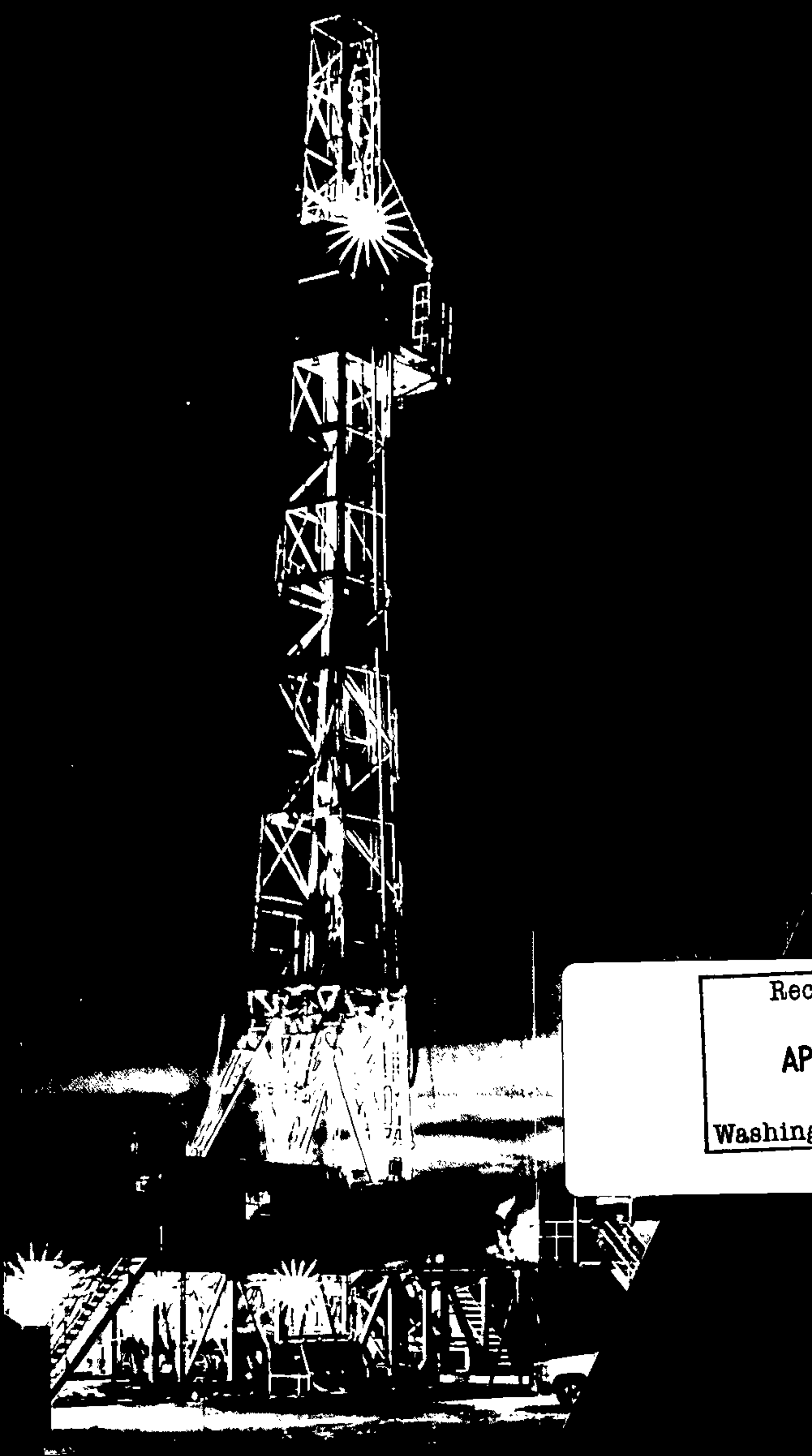
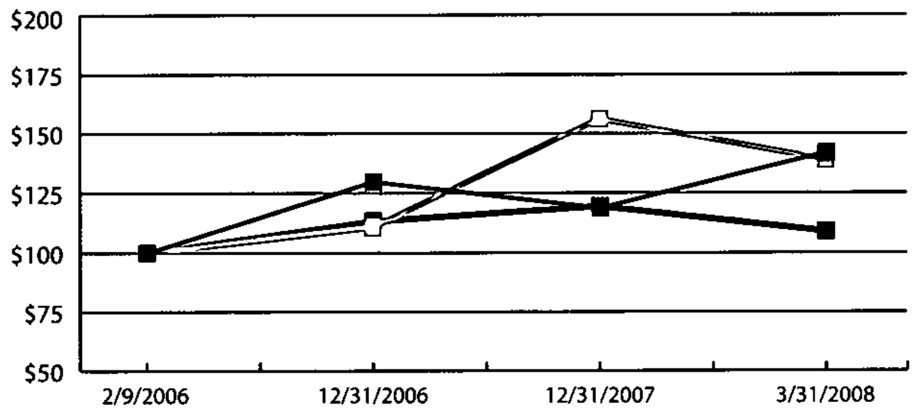


ANNUAL REPORT

EXCO

EXCO Resources, Inc.

EXCO's Common Stock Performance

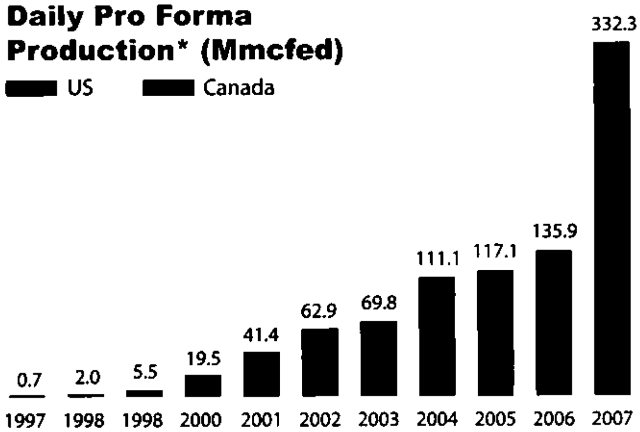


The graph to the right compares the cumulative total return (what $100 invested on February 9, 2006, the date of our IPO, would be worth today) on the company's common stock with the cumulative total return on the NYSE Market Index and the Crude Petroleum and Natural Gas SIC Code Index.

These historical comparisons are not a forecast of the future performance of our common stock or the referenced indexes.

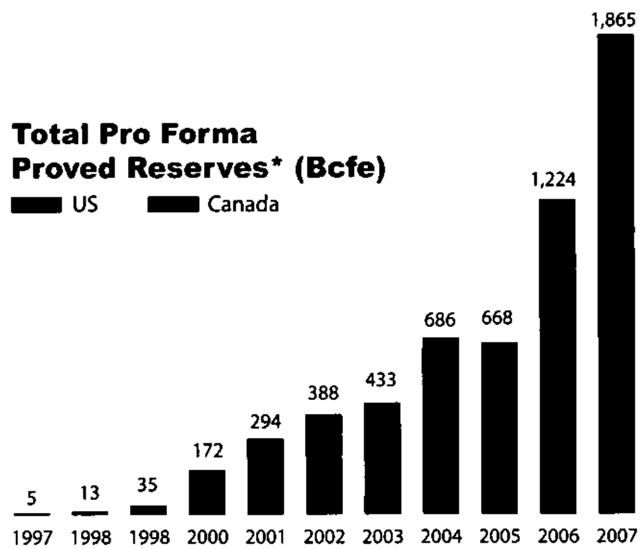
	Period Ended			
	2/9/2006	**12/31/2006**	**12/31/2007**	**3/31/2008**
EXCO Resources, Inc.	$ 100.00	$ 129.58	$ 118.62	$ 141.76
Crude Petroleum & Natural Gas	$ 100.00	$ 110.79	$ 156.21	$ 138.84
NYSE Market Index	$ 100.00	$ 113.27	$ 119.37	$ 108.95

Daily Pro Forma Production* (Mmcfed)



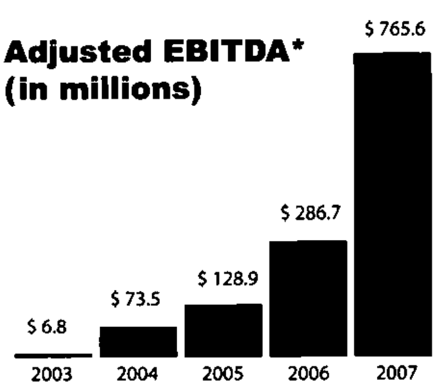
**We sold our wholly-owned Canadian subsidiary, Addison Energy Inc. in February 2005. Daily production in 2005 is pro forma for the acquisition of TXOK Acquisition, Inc., which was acquired by EXCO in February 2006.*

Total Pro Forma Proved Reserves* (Bcfe)



** We sold our wholly-owned Canadian subsidiary, Addison Energy Inc. in February 2005. Total proved reserves in 2005 are pro forma for the acquisition of TXOK Acquisition, Inc., which was acquired by EXCO in February 2006.*

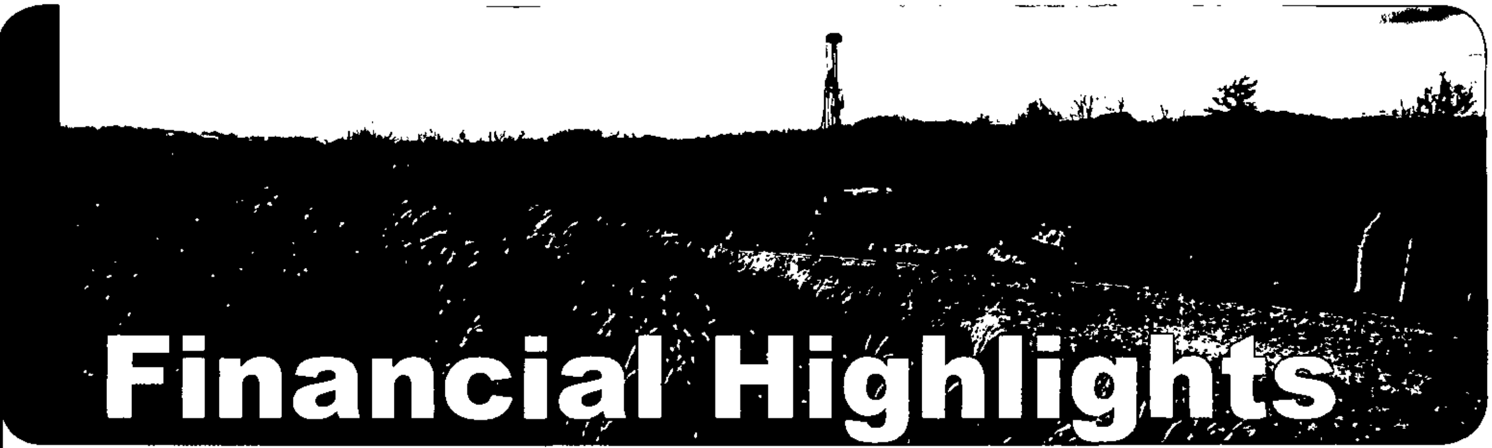
Adjusted EBITDA* (in millions)



**See our website at www.excoresources.com under Investor Relations for a reconciliation of this non-GAAP measure.*

EXCO RESOURCES, INC. is an oil and natural gas company engaged in the acquisition, development and exploitation of onshore North American oil and natural gas properties. Our operations are focused in key North American oil and natural gas regions including East Texas/North Louisiana, Appalachia, the Midcontinent and Permian Basin areas of the United States.

Our primary goal is to build value for our shareholders by acquiring quality properties and enhancing the value of our assets through control of operations, development of properties, exploitation of unproved upside and reduction of costs.



Financial Highlights

(in millions, except volume, wells drilled, productive wells and prices)

Results of Operations*	2004	Non-GAAP combined 2005	2006	2007	2006-2007 Change
	Years ended December 31,				
Oil and natural gas revenues					
(before effects of derivative financial instruments)	$ 142.0	$ 202.9	$ 355.8	$ 846.1	138%
Adjusted EBITDA	$ 73.5	$ 128.9	$ 286.7	$ 765.6	167%
Net income	$ 6.0	$ 1.2	$ 139.0	$ 49.7	(64)%
Net cash flow provided by (used in) operating activities	$ 118.5	$ (72.9)	$ 227.7	$ 577.8	154%
Total production (Bcfe)	23.0	23.5	49.6	121.3	145%
Productive wells drilled (gross)	97	108	367	495	35%
Drilling success rate	97%	97%	98%	98%	0%
Total acreage (gross)	0.7	1.0	1.5	1.8	20%
Total productive wells (gross)	4,663	6,468	8,964	10,312	15%

Financial Position*	2004	2005	2006	2007	2006-2007 Change
	Years ended December 31,				
Total assets	$ 922.1	$ 1,530.5	$ 3,707.1	$ 5,955.8	61%
Long-term debt, less current maturities	$ 487.5	$ 461.8	$ 2,081.7	$ 2,099.2	1%
Shareholders' equity	$ 203.7	$ 370.9	$ 1,179.9	$ 1,115.7	(5)%
Total proved reserves (Bcfe)	406	442	1,224	1,865	52%
Pre-tax present value, discounted at 10%	$ 700.4	$ 1,248.6	$ 1,606.0	$ 3,945.9	146%
Year-end NYMEX prices:					
Oil (per Bbl)	$ 43.33	$ 61.03	$ 60.82	$ 95.92	58%
Natural gas (per Mmbtu)	$ 6.18	$ 10.08	$ 5.64	$ 6.80	21%

* See our website at www.excoresources.com under Investor Relations for a reconciliation of non-GAAP measures, certain definitions, and explanations of and assumptions used in certain calculations.

Forward-looking Statements

We believe that it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. You are cautioned not to place undue reliance on a forward-looking statement. When considering our forward-looking statements, keep in mind the risk factors and other cautionary statements in this presentation, and the risk factors included in the Annual Report on Form 10-K for the year ended December 31, 2007, and our other periodic filings with the SEC.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil and natural gas. Declines in oil or natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil or natural gas prices also may reduce the amount of oil or natural gas that we can produce economically. A decline in oil and/or natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our oil and natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

The SEC has generally permitted oil and natural gas companies, in filings made with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. We use the terms "probable," "possible," "potential," "unproved," or "unbooked potential," to describe volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines strictly prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by the company. While we believe our calculations of unproved drillsites and estimation of unproved reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third party engineers or appraisers. Investors are urged to consider closely the disclosure in our Annual Report on Form 10-K for the year ended December 31, 2007, which is included herein.

To Our Fellow Shareholders

For EXCO Resources, 2007 marked another successful year on multiple fronts. Oil and natural gas revenues for the year were a record $846 million, and when the cash settlements of derivatives are included, revenues were $954 million. This clearly demonstrates the advantage of our strategic hedging program which provides cash flow stability in a volatile commodities market. Oil and natural gas production was 121 Bcfe for 2007 and 35 Bcfe for the fourth quarter, both record levels for the Company. Our daily production has increased throughout the year, averaging 377 Mmcfe per day for the fourth quarter. Other records set by the Company include our adjusted EBITDA, a non-GAAP measure, which was $766 million in 2007, approximately 2.7 times the prior year's level, and our fourth quarter adjusted EBITDA which was $227 million, approximately 2.3 times the prior year's quarter.

For EXCO, 2007 was an outstanding year both operationally and financially and a significant transition year. For most of 2005, 2006 and early 2007, we were primarily focused on accumulating a substantial, long-life resource base in four key areas – East Texas/North Louisiana, Appalachia, the Permian Basin and the Midcontinent. Through some $4.7 billion of acquisitions, coupled with approximately $980 million of divestitures in noncore areas and the sale of our Canadian operations, we more than accomplished our original goal. Since early 2007, we have concentrated on consolidation, staffing and identification of upside potential in our resource base. We have hired over 450 people since early 2006, including approximately 300 during 2007 alone. We concentrated on hiring the best technical staff available and added 49 geologists, engineers and other technical personnel. Through a concentrated technical review of our resource base, we identified 2.3 Tcfe of probable and possible reserves, over 10.5 Tcfe of unbooked potential and a substantial inventory of

- Total production increased 145% to 121 Bcfe in 2007
- Achieved 98% drilling success rate in 2007
- Total reserves exceeded 1.8 Tcfe at year-end 2007

production and reserve enhancements to our base assets. Included in the unbooked potential is our significant position in the rapidly developing Marcellus and Huron shale plays in Appalachia and the Haynesville shale play in East Texas and North Louisiana.

EXCO continues to set records in the field. We drilled and completed 495 gross wells in 2007 while maintaining an overall drilling success rate of 98%. Our capital expenditures, including our leasing, midstream and corporate activities totaled $525 million for the year. In March 2008, our capital budget was increased from approximately $625 million to $800 million by EXCO's board of directors. Of the $175 million increase, $150 million is for the exploitation of our Marcellus shale position in Appalachia which includes leasing of additional acreage in the play, drilling of both horizontal and vertical wells, and development of infrastructure to support our future growth of this major resource opportunity. The other $25 million of this increase is for additional Appalachian shallow drilling related to our acquisition of natural gas properties in February 2008. We now plan to drill nearly 700 gross wells during 2008.

Our concentration during 2008 will be in the following areas:

East Texas/North Louisiana – We plan to spend $339 million for development and drilling of 139 wells in 2008. We will continue to emphasize our Vernon and Holly Caspiana field development and exploitation activities and plan to drill at least five horizontal wells in East Texas and North Louisiana. In both Vernon and Holly Caspiana, we continue to expand the field limits.

Appalachia – In Appalachia, we will spend $93 million on our shallow Clinton, Medina, Devonian sandstone resource base and drill 322 wells. As noted above, we recently acquired additional shallow natural gas properties primarily in our central Pennsylvania operating area. We will add 3-4 rigs in the area to begin aggressively developing the newly

- Adjusted EBITDA up 167% to $765.6 million in 2007
- PV-10 increased to $3.9 billion at year-end 2007
- Drilled and completed 495 wells in 2007

acquired locations. We plan to drill at least 10 vertical wells and 4 horizontal wells on our extensive Marcellus shale acreage. We have over 240,000 net acres in the overpressured, thicker Marcellus fairway and in excess of 360,000 net acres in the play. We have more than 122,000 net acres in the Huron shale area in West Virginia. We will spend more than $150 million in the Appalachian shale areas with significant emphasis on leasing additional acreage, drilling wells and developing infrastructure.

Other – In 2008, our Permian Canyon Sand field development and extension work will continue with a $98 million budget for drilling 156 wells, 147 of which are in the Sugg Ranch Field. We are budgeting $57 million of capital for the Midcontinent area and $15 million for the Rockies.

We have made significant strides in improving our internal controls and corporate infrastructure. 2007 was our first year for compliance with Sarbanes-Oxley Section 404 which governs management's assessment of internal controls. We are pleased to report that we received a clean opinion from our outside auditors, KPMG LLP. This result was from the hard work of our dedicated employees who worked tirelessly on our SOX effort. Our employees were also busy on another front. In the second half of 2006, we undertook an initiative to standardize and simplify our IT systems, emphasizing enterprise-wide solutions, from which to continue our rapid acquisition and growth strategy. During early 2007, we moved all of our divisions to leading upstream energy software programs.

In 2008, we will continue to concentrate our efforts on enhancing our asset base, developing our proved, probable and possible reserves and exploiting our significant potential reserves including the Marcellus and Huron shales in Appalachia, the Haynesville shale in East Texas and North Louisiana, and the East Texas and North Louisiana Cotton Valley reserves through our horizontal drilling plans. We will also continue to pursue acquisitions which complement our core holdings. We are very excited about the future prospects for EXCO. We feel the Company is well positioned to take advantage of future opportunities through the use of technologically enhanced drilling and production management and through the proper positioning of the Company in our 4 key operating areas.

Our ultimate goal of maximizing shareholder value would not be possible, though, without our most important asset, our employees. As of March 31, 2008, we have more than 740 full-time employees. The most important factors in EXCO's future success are the expertise and dedication of our people. Our team will continue to build a quality asset base through the execution of a well disciplined strategic plan.

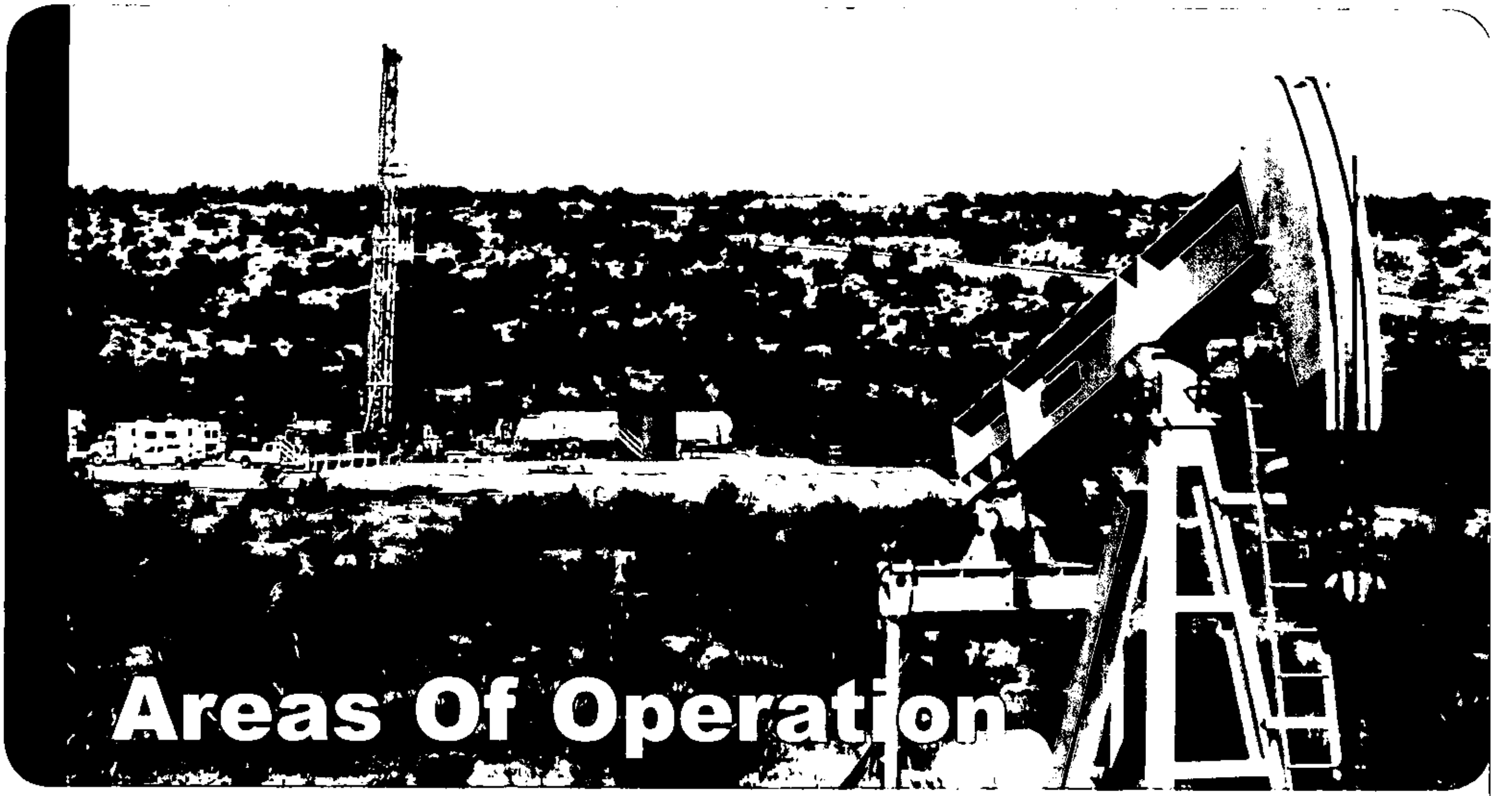
On behalf of our entire Company, we would like to thank you for your continued support. We look forward to another great year for EXCO.

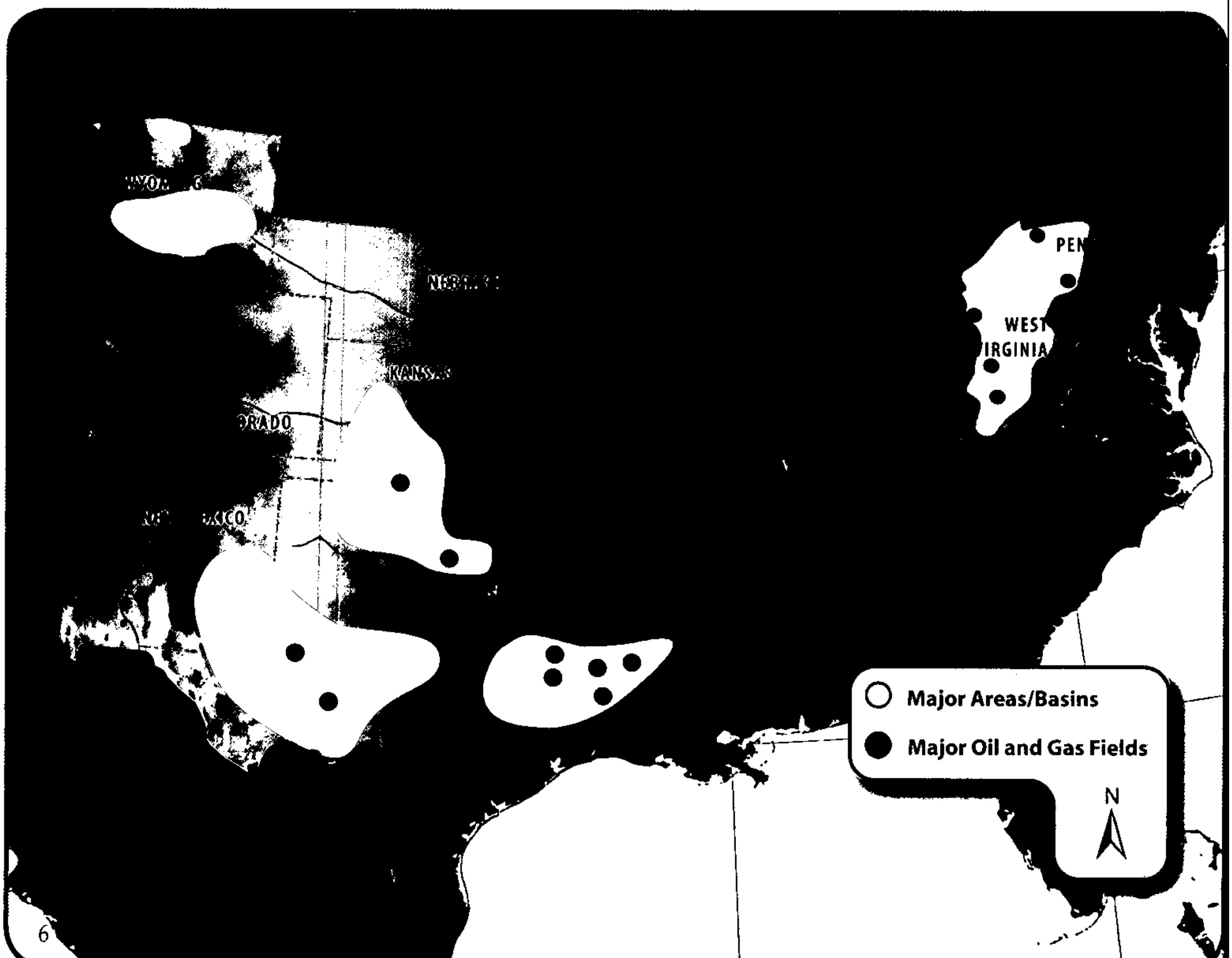
Sincerely,

Douglas H. Miller
Douglas H. Miller
Chairman of the Board
and Chief Executive Officer

Stephen F. Smith
Stephen F. Smith
Vice Chairman of the
Board and President

Areas Of Operation






EXCO

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2007

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 0-9204

EXCO RESOURCES, INC.

(Exact name of Registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	**74-1492779** (I.R.S. Employer Identification No.)
12377 Merit Drive, Suite 1700, LB 82 **Dallas, Texas** (Address of principal executive offices)	**75251** (Zip Code)

Registrant's telephone number, including area code: **(214) 368-2084**

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

Title of each class	**Name of each exchange on which registered**
Common Stock, $0.001 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None
(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

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

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

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

As of February 15, 2008, the registrant had 104,641,636 outstanding shares of common stock, par value $.001 per share, which is its only class of common stock. As of the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of our common stock held by non-affiliates was $1,269,540,000.

For purposes of this calculation only, affiliates include all shares held by all officers, directors and 10% or greater shareholders.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement to be furnished to shareholders in connection with its 2008 Annual Meeting of Shareholders are incorporated by reference in Part III, Items 10-14 of this Annual Report on Form 10-K.

TABLE OF CONTENTS

EXCO RESOURCES, INC.

PART I

ITEM 1. BUSINESS

General

Unless the context requires otherwise, references in this Annual Report on Form 10-K to "EXCO," "EXCO Resources," "Company," "we," "us," and "our" are to EXCO Resources, Inc., its consolidated subsidiaries and EXCO Holdings Inc., or EXCO Holdings, our former parent company that merged with us on February 14, 2006.

The period that began on January 1, 2005 and ended on October 2, 2005 is referred to in this Annual Report on Form 10-K as Predecessor. The Predecessor period represents the accounting period up to October 3, 2005, when all of the outstanding equity securities of EXCO Holdings were purchased in a private transaction, or the Equity Buyout. The period that began on October 3, 2005 and ended on December 31, 2005, and the years ended December 31, 2006 and December 31, 2007 are referred to as Successor.

We have provided definitions of terms commonly used in the oil and natural gas industry in the "Glossary of selected oil and natural gas terms" beginning on page 27.

EXCO Resources, a Texas corporation incorporated in October 1955, is an independent oil and natural gas company engaged in the acquisition, development and exploitation of onshore North American oil and natural gas properties. Our operations are focused in key North American oil and natural gas areas including East Texas/North Louisiana, Appalachia, Mid-Continent and Permian. As of December 31, 2007, our Proved Reserves were approximately 1.9 Tcfe, of which 93.3% were natural gas and 70.8% were Proved Developed Reserves. As of December 31, 2007, the related PV-10 of our Proved Reserves was approximately $3.9 billion, and the Standardized Measure of our Proved Reserves was $3.1 billion (see "—Summary of geographic areas of operation" for a reconciliation of PV-10 to Standardized Measure of Proved Reserves). For the twelve months ended December 31, 2007, we produced 121.3 Bcfe of oil and natural gas. Based on our December 2007 average daily production of 377 Mmcfe/d, this translates to a reserve life of approximately 13.6 years.

Our business strategy

We plan to achieve reserve, production, and cash flow growth by executing our strategy as highlighted below:

- ***Exploit our multi-year development inventory***

  We have a multi-year inventory of development drilling locations and exploitation projects. This inventory consists of step-out drilling, infill drilling, workovers, and recompletions. From January 1, 2007 to December 31, 2007, we drilled 506 wells and completed 495 wells resulting in a 98% drilling success rate. We have identified over 10,000 drilling locations and exploitation projects across our properties.

- ***Seek acquisitions that meet our strategic and financial objectives***

  We maintain a disciplined acquisition process to seek and acquire properties that have established production histories and value enhancement potential through development drilling and exploitation projects. Examples of this strategy include our acquisitions of North Coast Energy, Inc., or North Coast, in the Appalachian Basin, TXOK Acquisition, Inc., or TXOK, in the East Texas and the Mid-Continent areas and Winchester Energy Company, Ltd., or Winchester, in the East Texas and North Louisiana areas, our 2007 acquisitions from Anadarko Petroleum Corporation, or Anadarko, in the Vernon and Ansley Fields located in Jackson Parish, Louisiana, or the Vernon Acquisition, and multiple fields primarily in Oklahoma, Texas and Louisiana, or the Southern Gas Acquisition.

- ***Identify and exploit upside opportunities on our acquired properties***

  Our acquisitions often lead to upside above that identified at the date of acquisition. We have significant acreage holdings in the Marcellus shale resource play in Appalachia and are leasing additional acreage to add to our current position which exceeds 350,000 net acres, drilling both vertical and horizontal wells to confirm the opportunity and high grade our focus area, and adding appropriate staff to support our efforts. In our East Texas/North Louisiana area, we plan to drill horizontal wells, implement down spacing of vertical wells, and recomplete and restimulate existing wells to enhance our production and reserve position. In our Rockies area we hold more than 132,000 net acres primarily in the Wind River, Powder River and Big Horn Basins. We are drilling wells in this area to evaluate our position and plan additional development.

- ***Actively manage our portfolio and associated costs***

  We periodically review our properties to identify cost savings opportunities and divestiture candidates. We actively seek to dispose of properties with higher operating costs and properties that are not within our core geographic operating areas. We also seek to opportunistically divest properties in areas in which acquisitions and investment economics no longer meet our objectives, most notably the sale of our Canadian subsidiary for $443.4 million in February 2005, the sale of our Wattenberg Field operations in Colorado for $130.9 million in January 2007, the sale of a portion of the oil and natural gas properties and related assets in multiple fields primarily located in South Texas and South Louisiana acquired in the Southern Gas Acquisition, or the Gulf Coast Sale, on May 8, 2007 for $235.5 million in cash and 750,000 shares of unregistered restricted Crimson common stock and the sale of our properties in the Cement Field on July 13, 2007 for $99.7 million.

- ***Maintain financial flexibility***

  We employ the use of debt and equity along with a comprehensive derivative financial instrument program to support our acquisition strategy. This approach enhances our ability to execute our business plan over the entire commodity price cycle, protect our returns on investments, and manage our capital structure.

Our strengths

We have a number of strengths that we believe will help us successfully execute our strategy.

- ***Experienced management team with significant employee ownership***

  Our management team has led both public and private oil and natural gas companies over the past 20 years and has an average of over 26 years of industry experience in acquiring, developing, and exploiting oil and natural gas properties. Our management team first purchased a significant ownership interest in us in December 1997, and since then we have achieved substantial growth in reserves and production. Since the beginning of 1998, we have increased our Proved Reserves from approximately 4.7 Bcfe to approximately 1.9 Tcfe at December 31, 2007, and our average daily production increased from less than 1 Mmcfe/d in 1997 to 377 Mmcfe/d in December 2007. As of February 15, 2008, our management team and employees (excluding our outside directors) own approximately 13.0% of our issued and outstanding common stock and exercisable stock options and our outside directors or their affiliates own approximately 19.7% of our issued and outstanding common stock and exercisable stock options, which aligns their objectives with those of our shareholders.

- ***High quality asset base in attractive regions***

  We own and plan to maintain a geographically diversified reserve base. Our principal operations are in the East Texas/North Louisiana, Appalachia, Mid-Continent and Permian areas. Our properties are generally characterized by:

  - long reserve lives;
  - a multi-year inventory of development drilling and exploitation projects;
  - high drilling success rates; and
  - a high natural gas concentration.

- ***Operational control***

  We operate a significant portion of our properties, which permits us to manage our operating costs and better control capital expenditures as well as the timing of development and exploitation activities. As of December 31, 2007, we were the operator of 9,273 gross wells which represented approximately 95% of our Proved Reserves.

Significant transactions during 2007

Private placement of preferred stock. On March 30, 2007, we completed a private placement, or Private Placement, of an aggregate of $390.0 million of 7.0% Cumulative Convertible Perpetual Preferred Stock, or 7.0% Preferred Stock, and $1.61 billion of Hybrid Preferred Stock, or Hybrid Preferred Stock, to accredited investors pursuant to the terms and conditions of a Preferred Stock Purchase Agreement dated March 28, 2007. The purchase price for each share was $10,000 (which equaled the liquidation preference per share on March 30, 2007). The issuance and sale of the shares in the Private Placement was exempt from registration under the Securities Act of 1933, or Securities Act, pursuant to Section 4(2) thereof and Regulation D promulgated thereunder.

The net proceeds of the Private Placement were used to fund the purchase price of approximately $1.5 billion for the Vernon Acquisition on March 30, 2007 and to repay certain outstanding indebtedness.

The 7.0% Preferred Stock is convertible into shares of our common stock at an initial conversion price of $19.00 per share, subject to anti-dilution adjustments, which equates to each share of 7.0% Preferred Stock being initially convertible into approximately 526.3 shares of our common stock, subject to adjustment for fractional shares. The Hybrid Preferred Stock was not initially convertible into shares of our common stock. Under applicable New York Stock Exchange, or NYSE, rules, shareholder approval is required to issue common stock, or securities convertible into or exercisable for common stock, if (i) such common stock has, or will have upon issuance, 20.0% or more of the voting power outstanding before the issuance, (ii) the number of shares of common stock to be issued is, or will be upon issuance, equal to 20.0% or more of the number of shares of common stock outstanding before the issuance, (iii) such common stock, or securities convertible into or exercisable for common stock, will be issued to a director, officer or substantial security holder of the Company and such securities exceed either a threshold of one percent or, if issued to a substantial security holder who is not a director or officer at a price that is not less than the book and market value of the common stock, five percent of the number of shares of common stock or the voting power outstanding before the issuance or (iv) such issuance will result in a change of control of the Company.

Absent NYSE rules, we likely would have issued 200,000 shares of 7.0% Preferred Stock to fund the Vernon Acquisition and to repay certain outstanding indebtedness. As a result of the limited time period to fund the Vernon Acquisition and the time required to organize a special meeting of shareholders, we were unable to hold a special meeting of our shareholders to approve the issuance of 200,000 shares of 7.0% Preferred Stock prior to the Vernon Acquisition. Therefore, in the interim, we issued 39,008 shares of 7.0% Preferred Stock and 160,992 shares of Hybrid Preferred Stock.

We agreed with the preferred stock investors to seek the shareholder approval required by the NYSE, or NYSE Shareholder Approval, to transform the terms of the Hybrid Preferred Stock into the same terms as the 7.0% Preferred Stock. On August 30, 2007, NYSE Shareholder Approval was obtained and the designations, preferences, limitations and relative voting rights of the Series A-1 Hybrid Preferred Stock and Series A-2 Hybrid Preferred Stock became identical to the designations, preferences, limitations and relative voting rights of the Series A-1 7.0% Preferred Stock and the Series A-2 7.0% Preferred Stock, respectively, including the right to receive dividends at an annual rate of 7.0% and the right to convert into shares of our common stock at an initial conversion price of $19.00 per share, subject to anti-dilution adjustments.

Principal terms of the Preferred Stock

The following summarizes the principal terms of the 7.0% Preferred Stock and the Hybrid Preferred Stock. This discussion is not complete and is qualified in its entirety by, and should be read in conjunction with, the Statements of Designation establishing each series of the 7.0% Preferred Stock and the Hybrid Preferred Stock, which are filed as exhibits to our Current Report on Form 8-K dated March 28, 2007 and filed with the Securities and Exchange Commission, or the SEC, on April 2, 2007 and are incorporated by reference herein.

Series A-1 7.0% Preferred Stock

The Series A-1 7.0% Preferred Stock has an initial liquidation preference equal to $10,000 per share and is convertible into common stock at a price of $19.00 per share, as may be adjusted in accordance with the terms of the Series A-1 7.0% Preferred Stock. We may force the conversion of the Series A-1 7.0% Preferred Stock at any time if the common stock trades for 20 days within a period of 30 consecutive days at a price (i) above 175% of the then effective conversion price ($33.25 per share at the current conversion price of $19.00 per share) at any time during the 24 months after issuance, (ii) above 150% of the then effective conversion price ($28.50 per share at the current conversion price of $19.00 per share) thereafter through the 48th month after issuance and (iii) above 125% of the then effective conversion price ($23.75 per share at the current conversion price of $19.00 per share) at any time thereafter. Cash dividends will accrue at the rate of 7.0% per annum prior to March 30, 2013 and at the rate of 9.0% per annum thereafter. In lieu of paying cash dividends, we may, under certain circumstances prior to March 30, 2013, pay dividends at a rate of 9.0% per annum by adding the dividends to the liquidation preference of the shares of Series A-1 7.0% Preferred Stock. Upon the occurrence of a change of control, holders of the Series A-1 7.0% Preferred Stock may require us to repurchase their shares for cash at the liquidation preference plus accumulated dividends. Holders of the Series A-1 7.0% Preferred Stock have the right to vote with the holders of common stock, the holders of other series of 7.0% Preferred Stock and the holders of Hybrid Preferred Stock, together as a single class, on all matters submitted to our shareholders (except the election of directors) on an as-converted basis. Holders of Series A-1 7.0% Preferred Stock, Series B 7.0% Preferred Stock, Series C 7.0% Preferred Stock and Series A-1 Hybrid Preferred Stock have the right to separately elect up to four directors, subject to the rights of the holders of Series B 7.0% Preferred Stock and Series C 7.0% Preferred Stock to vote as separate classes to each elect one of such preferred directors. In addition, upon the occurrence of specified defaults in the Statements of Designation for the 7.0% Preferred Stock and the Hybrid Preferred Stock, the holders of the 7.0% Preferred Stock and Hybrid Preferred Stock, voting together as a class, have the right to elect four additional directors, or Default Directors, until such default is cured.

Series B 7.0% Preferred Stock

The Series B 7.0% Preferred Stock has substantially the same rights as the Series A-1 7.0% Preferred Stock, except that the holders of Series B 7.0% Preferred Stock have the right to designate one of the preferred directors and do not have registration rights under the 7.0% Registration Rights Agreement. The Series B 7.0% Preferred Stock is convertible into Series A-1 7.0% Preferred Stock at any time at the election of the holder and will automatically convert into Series A-1 7.0% Preferred

Stock when such holder ceases to own an aggregate of 10,000 shares of Series B 7.0% Preferred Stock and/or Hybrid Preferred Stock.

Series C 7.0% Preferred Stock

The Series C 7.0% Preferred Stock has substantially the same rights as the Series A-1 7.0% Preferred Stock, except that the holders of Series C 7.0% Preferred Stock have the right to designate one of the preferred directors and do not have any registration rights under the 7.0% Registration Rights Agreement. The Series C 7.0% Preferred Stock is convertible into Series A-1 7.0% Preferred Stock at any time at the election of the holder and will automatically convert into Series A-1 7.0% Preferred Stock when such holder ceases to own an aggregate of 10,000 shares of Series C 7.0% Preferred Stock and/or Hybrid Preferred Stock.

Series A-1 Hybrid Preferred Stock

Since NYSE Shareholder Approval was obtained on August 30, 2007, the designations, preferences, limitations and relative voting rights of the Series A-1 Hybrid Preferred Stock became identical to the designations, preferences, limitations and relative voting rights of the Series A-1 7.0% Preferred Stock, including the right to dividends and the right to convert into our common stock.

7.0% Preferred Stock Registration Rights Agreement

In connection with the Private Placement, we entered into the 7.0% Registration Rights Agreement with the preferred stock investors. The 7.0% Registration Rights Agreement contemplates the registration of the resale of the shares of common stock underlying the 7.0% Preferred Stock and the Hybrid Preferred Stock. The 7.0% Registration Rights Agreement contains customary terms and conditions for a transaction of this type. We agreed to file with the SEC, not later than September 26, 2007, a registration statement to register the offer and sale of the common shares issuable upon conversion of the 7.0% Preferred Stock and the Hybrid Preferred Stock and to use our best efforts to have the registration statement declared effective by March 24, 2008. On September 5, 2007, we filed an automatically effective registration statement on Form S-3 with the SEC to register for resale the shares of common stock issuable upon conversion of the Series A-1 Hybrid Preferred Stock and the Series A-1 7.0% Preferred Stock. If any shares of 7.0% Preferred Stock or Hybrid Preferred are outstanding on March 30, 2011, we agreed to file a registration statement with the SEC by June 28, 2011 registering such shares for resale and to use our best efforts to have such registration statement declared effective by September 26, 2011. If we are unable to meet the deadlines described above, if a registration statement ceases to remain effective or if we restrict sales under a registration statement under certain "blackout provisions" for longer than the contractually permitted period, we must pay liquidated damages at a rate of 0.5% per annum of the liquidation preference applicable to the 7.0% Preferred Stock and the Hybrid Preferred Stock for the first 90 days and thereafter for each subsequent 90-day period at an additional rate of 0.25% up to a maximum of 2.0% per annum during any default period. We also agreed to indemnify holders against certain liabilities under the Securities Act in respect of any such resale registration.

Hybrid Preferred Stock Registration Rights Agreement

In connection with the Private Placement, we entered into a registration rights agreement, or Hybrid Registration Rights Agreement, with the Hybrid Preferred Stock investors. The Hybrid Registration Rights Agreement contemplates the registration of the resale of the shares of Series A-1 Hybrid Preferred Stock. If NYSE Shareholder Approval had not been obtained by September 26, 2007, we would have been required to file a registration statement with the SEC by December 24, 2007, covering the resale prior to such shareholder approval of shares of Hybrid Preferred Stock and to use our best efforts to have the registration statement declared effective by March 24, 2008. The Hybrid Registration Rights Agreement and the obligation of the parties thereunder terminated on August 30, 2007 because NYSE Shareholder Approval was obtained.

Vernon Acquisition. On March 30, 2007, EXCO Partners Operating Partnership, a wholly-owned unrestricted subsidiary of EXCO, or EPOP, completed the purchase of substantially all of the oil and natural gas properties and related assets, including derivative financial instruments, covering a significant portion of estimated production for 2007, 2008 and 2009 from entities affiliated with Anadarko in the Vernon and Ansley fields located in Jackson Parish, Louisiana for approximately $1.5 billion in cash, net of purchase price adjustments. The Vernon Acquisition was funded by a $1.75 billion capital contribution from EXCO to EPOP. The capital contribution consisted of $1.67 billion in cash and application of an $80.0 million deposit paid by EXCO to Anadarko in December 2006.

Amended and restated credit agreement of EPOP. Concurrent with the Vernon Acquisition, EPOP entered into an Amended and Restated Credit Agreement, or the EPOP Credit Agreement, among EPOP, as borrower, certain subsidiaries of EPOP, as guarantors, and certain lenders. The initial interest rate was London Inter Bank Offered Rate, or LIBOR, plus 150 basis points with a maximum rate of LIBOR plus 175 basis points. The material changes reflected in the EPOP Credit Agreement included an increase in the borrowing base from $750.0 million to $1.3 billion, principally to reflect the assets acquired in the Vernon Acquisition. EPOP used a portion of the increased borrowing capacity and the remaining cash from EXCO's capital contribution to repay $668.7 million of an existing EPOP term loan, or the Senior Term Credit Facility, which included principal of $650.0 million, accrued interest of $5.7 million and a prepayment premium of $13.0 million. Upon consummation of the Vernon Acquisition and repayment of the Senior Term Credit Facility, approximately $1.1 billion was outstanding under the EPOP Credit Agreement.

Southern Gas Acquisition. On May 2, 2007, we completed the purchase of oil and natural gas properties and related assets, including derivative financial instruments, covering a significant portion of estimated production for 2007, 2008 and 2009 from entities affiliated with Anadarko in multiple fields primarily located in Oklahoma, Texas and Louisiana for approximately $761.1 million in cash, including acquisition related expenses, net of preliminary purchase price adjustments. The Southern Gas Acquisition was funded with cash on hand of $145.2 million, including $133.0 million from like-kind exchange escrow accounts from prior sales, borrowings under the EXCO Resources credit agreement of $572.9 million and the application of a $43.0 million deposit paid by EXCO to Anadarko in February 2007.

On May 2, 2007, in connection with the Southern Gas Acquisition, EXCO entered into the Second Amended and Restated Credit Agreement, or the EXCO Resources Credit Agreement, among EXCO, as borrower, certain subsidiaries of EXCO, as guarantors, and a group of lenders. As a result of the Southern Gas Acquisition, EXCO and the lenders agreed to increase the borrowing base from $750.0 million to $1.0 billion.

Other 2007 acquisitions. On October 9, 2007, we completed the acquisition of an additional 45% interest in approximately 28,000 acres of leasehold interests and 135 producing wells in our Canyon Sand field in West Texas for $155.0 million, after post-closing purchase price adjustments.

In October 2007, we completed the acquisition of more than 300 producing wells and associated undeveloped sites within our core central Pennsylvania operating area for approximately $16.2 million.

Summary of 2007 acquisition activity. During 2007, we completed the following acquisitions of oil and natural gas properties and undeveloped acreage. A summary of these acquisitions and the values allocated to oil and natural gas properties and gathering facilities, net of contractual adjustments, is presented on the following table.

(in thousands)	Vernon Acquisition	Southern Gas Acquisition	Other acquisitions	Consolidated total
Purchase price calculations:				
Purchase price	$1,520,183	$759,100	$180,160	$2,459,443
Acquisition related expenses	1,755	2,040	—	3,795
Total purchase price	$1,521,938	$761,140	$180,160	$2,463,238
Allocation of purchase price:				
Proved oil and natural gas properties	$1,417,823	$577,852	$159,502	$2,155,177
Unproved oil and natural gas properties	58,192	4,743	20,658	83,593
Gulf coast sale	—	235,477	—	235,477
Gas gathering and related facilities	119,409	—	—	119,409
Fair value (liability) of assumed derivative financial instruments	(60,015)	(42,204)	—	(102,219)
Asset retirement obligations	(10,726)	(12,567)	—	(23,293)
Other liabilities, net	(2,745)	(2,161)	—	(4,906)
Total purchase price allocation	$1,521,938	$761,140	$180,160	$2,463,238

Gulf Coast Sale. On May 8, 2007, we completed the sale of a portion of the oil and natural gas properties and related assets in multiple fields primarily located in South Texas and South Louisiana acquired in the Southern Gas Acquisition to an entity affiliated with Crimson Exploration Inc., or Crimson, for an aggregate sale price of $235.5 million in cash, net of preliminary purchase price adjustments, and 750,000 shares of unregistered restricted Crimson common stock. In connection with the closing of the Gulf Coast Sale, the borrowing base on the EXCO Resources Credit Agreement was reduced from $1.0 billion to $900.0 million.

On August 15, 2007, we sold the 750,000 shares of unregistered restricted common stock of Crimson for an aggregate sales price of approximately $5.2 million. We recorded a gain of $0.7 million on the sale, which is included in other income for the year ended December 31, 2007.

Other 2007 sales of oil and natural gas properties. On January 5, 2007, we completed the sale of oil and natural gas properties and undeveloped drilling locations in the Wattenberg Field area of the DJ Basin, or the Wattenberg Field, for approximately $130.9 million, net of contractual adjustments. The transaction included substantially all of the assets EXCO held in the area. Proceeds from the sale were deposited with a third party intermediary pending closing of the Southern Gas Acquisition to facilitate a like-kind exchange for federal income tax purposes.

On July 13, 2007, we completed the sale of substantially all of our interest in the Cement Field, located in Caddo and Grady Counties, Oklahoma in our Mid-Continent area for approximately $99.7 million, after contractual purchase price adjustments. Proceeds from this sale were deposited with a third party intermediary and used to purchase assets in West Texas in October 2007.

In November 2007, we sold certain assets across our portfolio for approximately $20.4 million, subject to post-closing adjustments. Through this divestiture, we exited Nebraska, Colorado, and certain non-operated properties in Texas and the Gulf Coast area of Louisiana.

No gain or loss was recognized from these sales as we use the full cost method of accounting.

Pro forma results of operations. The following table reflects the unaudited pro forma results of operations as though the acquisitions of TXOK, Power Gas Marketing & Transmission, Inc., or PGMT, Winchester, the Private Placement, the Vernon Acquisition, the Southern Gas Acquisition and the Gulf Coast Sale had occurred on January 1, 2006.

(in thousands, except per share data)	Year ended December 31, 2006	Year ended December 31, 2007
Revenues and other income	$1,430,863	$1,063,492
Net income	335,129	101,697
Preferred stock dividends	(140,000)	(140,000)
Net income (loss) available to common shareholders	$ 195,129	$ (38,303)
Basic earnings (loss) per share	$ 2.02	$ (0.37)
Diluted earnings (loss) per share	$ 1.65	$ (0.37)

Significant subsequent events

Withdrawal of master limited partnership

On January 10, 2008, we announced the withdrawal of our registration statement related to our proposed master limited partnership. As such, approximately $3.5 to $4.5 million in registration costs, of which $3.4 million was deferred in 2007, will be expensed in the first quarter of 2008.

Financial Risk Management Instruments

In January 2008, we entered into financial risk management instruments to mitigate our exposure to fluctuations in interest rates on $700.0 million in principal through February 14, 2010 at LIBOR rates ranging from 2.45% to 2.8%.

Derivative Financial Instruments

Subsequent to December 31, 2007, we entered into additional derivative financial instruments covering 28,021 Mmbtu of natural gas and 731 Bbls of oil at weighted average prices of $8.79 per Mmbtu and $91.18 per Bbl, respectively.

Appalachian acquisition

On February 20, 2008, EXCO acquired shallow natural gas properties from EOG Resources, Inc. located primarily in EXCO's central Pennsylvania operating area. The properties include approximately 2,500 producing wells, 2,000 shallow undrilled locations and 16 Mmcfe/d of net production. The purchase price was $395.0 million. After reduction for preliminary closing adjustments of $7.4 million, the net purchase price paid on February 20, 2008 was $387.6 million and was financed with the EXCO Resources Credit Agreement.

Summary of geographic areas of operation

The following tables set forth summary operating information attributable to our principal geographic areas of operation as of December 31, 2007:

Areas	Total proved reserves (Bcfe) (1)	PV-10 (in millions) (1)(2)	Average December daily net production (Mmcfe/d)	Reserve life (years) (3)
East Texas/North Louisiana	974.3	$1,987.2	243.0	11.0
Appalachia	418.5	674.0	44.0	26.1
Mid-Continent	315.4	831.0	62.0	13.9
Permian	143.9	424.8	26.0	15.2
Rockies	13.0	28.9	2.0	17.8
Total	1,865.1	$3,945.9	377.0	13.6

Areas	Identified drilling locations(4)	Identified exploitation projects(5)	Total gross acreage	Total net acreage(6)
East Texas/North Louisiana	2,466	543	328,541	278,480
Appalachia	6,154	121	863,189	815,073
Mid-Continent	548	179	378,632	221,769
Permian	684	44	71,525	50,351
Rockies	150	7	147,998	132,456
Total	10,002	894	1,789,885	1,498,129

(1) The total Proved Reserves and the total PV-10 of the Proved Reserves, as used in this table, were prepared by Lee Keeling and Associates, Inc., or Lee Keeling, an independent petroleum engineering firm in Tulsa, Oklahoma. For each area set forth in the table, the Proved Reserves and PV-10 were extracted from the report from Lee Keeling by our internal engineers.

(2) The PV-10 data used in this table is based on December 31, 2007 spot prices of $6.80 per Mmbtu for natural gas and $95.92 per Bbl for oil, in each case adjusted for historical differentials. Market prices for oil and natural gas are volatile. See "Item 1A. Risk factors—Risks relating to our business." We believe that PV-10 before income taxes, while not a financial measure in accordance with generally accepted accounting principles, or GAAP, is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The total Standardized Measure for our Proved Reserves as of December 31, 2007 was $3.1 billion. The Standardized Measure represents the PV-10 after giving effect to income taxes, and is calculated in accordance with Statement of Financial Accounting Standards, or SFAS, No. 69 "Disclosures about Oil and Gas Producing Activities," or SFAS No. 69. The amount of estimated future abandonment costs, the PV-10 of these costs and the Standardized Measure were determined by us. We do not designate our derivative financial instruments as hedges and accordingly, do not include the impact of derivative financial instruments when computing the Standardized Measure.

The following table provides a reconciliation of our PV-10 to our Standardized Measure as of December 31, 2007:

(in millions)	
PV-10	$ 3,945.9
Future income taxes	(1,857.5)
Discount of future income taxes at 10% per annum	1,030.5
Standardized Measure	$ 3,118.9

(3) For purposes of this table, the reserve life is calculated by dividing the Proved Reserves (on an Mmcfe basis) at the end of the period by the daily production volumes for the month then ended, which production volume is annualized by multiplying by 365.

(4) Identified drilling locations represent total gross drilling locations identified and scheduled by our management as an estimation of our multi-year drilling activities on existing acreage. Of the total locations shown in the table, 2,370 are classified as proved. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, drilling results and other factors. See "Item 1A. Risk factors—Risks relating to our business."

(5) Identified exploitation projects represent total gross exploitation projects, such as workovers, recompletions, and other non-drilling activities, identified and scheduled by our management as an estimation of our multi-year exploitation projects on existing acreage. Of the total exploitation projects shown in the table, 425 are classified as proved. Our actual exploitation projects may change depending on the availability of capital, regulatory approvals, seasonal restrictions, oil and

natural gas prices, costs, and other factors. See "Item 1A. Risk factors—Risks relating to our business."

(6) Includes 100,454, 74,083 and 73,042 net acres with leases expiring in 2008, 2009 and 2010, respectively.

Our development and exploitation project areas

East Texas/North Louisiana

The East Texas/North Louisiana area is a part of the Cotton Valley Sand trend, which covers parts of the East Texas Basin and the Northern Louisiana Salt Basin. We are targeting tight sand reservoirs along the Cotton Valley Sand trend at depths of 6,500 to 15,000 feet. Operations in the area are generally characterized by long-lived reserves, high drilling success rates and wells with relatively high initial production rates. Due to the tight nature of the reservoirs, development programs in the area are mostly focused on infill development drilling. Many areas have been down spaced to 80 acres per well, with some areas having economically established 40 acre spacing.

Vernon Field

The Vernon Field, located in Jackson Parish, Louisiana, is our largest producing field, accounting for approximately one-third of our production. The field and gathering system were acquired from Anadarko on March 30, 2007. At December 31, 2007, we had Proved Reserves of 467.5 Bcfe and 365 gross producing wells. Most of the wells in the field produce from the Lower Cotton Valley and Bossier formations at approximately 12,000 to 15,000 feet. We gather and treat our own gas and have access to numerous transmission lines. In 2008 we plan to drill 24 wells.

East Texas/North Louisiana Cotton Valley Area

Within our Cotton Valley Area, we are active in Harrison, Panola, Smith, Rusk, Upshur and Gregg Counties in Texas, primarily across six fields—Waskom, Overton, Oak Hill, Minden, Glenwood and White Oak. We are also active in Caddo Parish and DeSoto Parish in Louisiana, primarily across four fields—Holly, Kingston, Caspiana and Longwood. At December 31, 2007, we had Proved Reserves of 506.8 Bcfe and 1,206 gross producing wells. We are focused on developing the Lower Cotton Valley (Taylor) and Upper Cotton Valley sands at depths of 10,400 to 11,000 feet, the Pettet Lime at depths of 7,000 to 8,500 feet and Travis Peak Sands at depths of 7,800 to 10,000 feet. Our natural gas is gathered through our own gathering lines in these fields. In 2008 we plan to drill 115 wells.

Appalachia

The Appalachian Basin includes portions of the states of Kentucky, Ohio, Pennsylvania, Virginia, West Virginia and Tennessee, and covers an area of over 185,000 square miles. It is the most mature oil and natural gas producing region in the United States, first establishing oil production in 1859. The Appalachian Basin is strategically located near high energy demand areas with limited supply. As a result, the natural gas produced from the area typically commands a higher wellhead price relative to other North American areas.

Although the Appalachian Basin has sedimentary formations indicating the potential for deposits of oil and natural gas reserves up to depths of 30,000 feet or more, most production in this area has been derived from relatively shallow, low porosity and permeability sand and shale formations at depths of 1,000 to 6,000 feet. Operations in the area are generally characterized by long reserve lives, high drilling success rates and a large number of low productivity wells in these shallow formations. In the Appalachian Basin, there are more than 200,000 producing wells and 3,100 operators, with most being relatively small, private enterprises. Our operations in the area primarily include development drilling on our existing acreage, as well as the acquisition of properties with established production and growth opportunities. We believe that the number of wells and operators presents a significant consolidation opportunity.

Northwestern Pennsylvania Area

The Northwestern Pennsylvania Area stretches across eight counties in northwestern Pennsylvania. At December 31, 2007, we had Proved Reserves of 25.6 Bcfe and 602 gross producing wells. Drilling, completion and production activities target the Silurian Medina Sandstone formation at depths of 4,500 to 5,100 feet. We currently plan to drill 29 wells in 2008.

Central Pennsylvania Area

The Central Pennsylvania Area encompasses a band across 13 counties in central Pennsylvania. At December 31, 2007, we had Proved Reserves of 188.9 Bcfe and 2,220 gross producing wells. Drilling, completion and production activities target the multiple, laterally stratified reservoirs of the Upper Devonian Venango, Bradford and Elk sandstone groups at depths ranging from 1,800 to 4,600 feet. We currently plan to drill 132 wells in 2008.

Eastern Ohio Area

The Eastern Ohio Area includes some 25 counties in eastern Ohio. At December 31, 2007, we had Proved Reserves of 72.7 Bcfe and 1,657 gross producing wells. Drilling, completion and production activities target the Silurian Clinton Sandstone found at depths of 3,500 to 5,600 feet and the Knox series at depths approaching 7,500 feet. We currently plan to drill 31 wells in 2008.

Northern West Virginia Area

The Northern West Virginia Area includes 17 counties located in northern West Virginia. At December 31, 2007, we had Proved Reserves of 76.3 Bcfe and 1,388 gross producing wells. Drilling, completion and production activities target the multiple, laterally stratified reservoirs of the Mississippian and Devonian formations found at depths of 2,500 to 4,500 feet. We currently plan to drill 19 wells in 2008.

Southern West Virginia Area

The Southern West Virginia Area includes 12 counties in southern West Virginia. At December 31, 2007, we had Proved Reserves of 48.9 Bcfe and 786 gross producing wells. Drilling, completion and production activities target the multiple, laterally stratified reservoirs of the Mississippian and Devonian formations found at depths of 1,500 to 5,500 feet. We currently plan to drill 6 wells in 2008.

Marcellus Shale Play

In Appalachia, we hold in excess of 800,000 net leasehold acres. Our land staff is focused on acquiring additional leasehold in our traditional shallow producing areas as well as in the Marcellus shale play fairway. Included in our extensive acreage position, we have approximately 350,000 net acres in the Marcellus shale, much of which is held by shallow production. More than 190,000 net acres are in the core area of the overpressured Marcellus play. Efforts continue to evaluate and develop plans relating to exploitation of the Marcellus shale play, and we have begun staffing in preparation for exploitation of our Marcellus shale position. Successful testing of the Marcellus shale has been conducted on four wells located in the shallower, normal to under-pressured areas of the basin where Marcellus production is being commingled with other, more traditional horizons to improve overall well economics. Testing of stand-alone horizontal wellbore completions in the over-pressured shale is planned for 2008.

Mid-Continent

The Mid-Continent area includes parts of Oklahoma, southwestern Kansas and the Texas Panhandle. The major properties in the Mid-Continent area are located in the Anadarko Shelf and Anadarko Basin of Oklahoma. The Mid-Continent area is characterized by stratigraphic plays with multiple, stacked pay zones and more complex geology than in our other operating areas. Similar to our other operating areas, the Mid-Continent area contains a number of fields with long production histories. We also recognize the potential for additional attractive acquisition opportunities, as this area contains a number of smaller operators seeking liquidity opportunities and some larger companies seeking to divest non-core assets.

Mocane-Laverne Field

The Mocane-Laverne Field is primarily located in Beaver, Harper and Ellis Counties of Oklahoma. At December 31, 2007, we had estimated Proved Reserves of 92.0 Bcfe and we had 695 gross producing wells. Primary drilling targets include the Morrow, Chester and Cherokee formations. Current producing wells have an average total depth of 7,161 feet. We currently plan to drill 37 wells during 2008.

Golden Trend Area

The Golden Trend Area is primarily located in Grady, Garvin and McClain Counties of Oklahoma. At December 31, 2007, we had estimated Proved Reserves of 157.1 Bcfe and we had 569 gross producing wells. Primary drilling targets are Sycamore, Hunton, Viola, Woodford, Simpson and Pennsylvanian formations. Current producing wells have an average total depth of 11,190 feet. We currently plan to drill 17 wells during 2008.

Permian

The Permian Basin is located in West Texas and the adjoining area of southeastern New Mexico. Though the Permian Basin is better known as a mature oil focused basin exploited with waterflood and other enhanced oil recovery techniques, our activities are focused on conventional natural gas properties. With the use of 3-D seismic, we are targeting prolific natural gas reservoirs with potential for multi-pay horizons. The properties are characterized by long reserve lives and low operating costs.

Sugg Ranch Field

The Sugg Ranch Field is located primarily in Irion County, Texas. We acquired an additional 45% interest in 135 producing wells and took over as operator in October 2007. This brings our total working interest to 97%. At December 31, 2007, we had Proved Reserves of 101.0 Bcfe and 160 gross producing wells. Production is primarily from the Canyon Sand from depths of 6,700 to 7,300 feet. We currently plan to drill 147 wells during 2008.

Rockies

The Rockies Area is located in Wyoming, Montana and Colorado. The region is mature and has been oil focused, with more recent emphasis on natural gas and coal-bed methane. The region can be complex geologically. Drill depths range from less than 1,000 feet to greater than 25,000 feet. Opportunities exist to acquire 3D seismic on existing fields to identify by-passed pay zones.

Rockies Area

The Rockies Area holdings consist of approximately 132,000 net acres of leasehold in Wyoming, primarily in the Wind River, Bighorn and Powder River Basins. At December 31, 2007, we had Proved Reserves of 13.0 Bcfe and 66 gross producing wells. We are targeting prolific natural gas reserves in the range of 2,000 to 14,000 feet with potential for multiple pays in each well. We currently plan to drill 9 wells in 2008.

Our oil and natural gas reserves

The following tables summarize historical information regarding Proved Reserves at December 31, 2005, 2006 and 2007. The historical information was prepared in accordance with the rules and regulations of the SEC.

	At December 31,		
	2005	2006	2007
Oil (Mmbbls)			
Developed	5.5	11.3	15.2
Undeveloped	1.3	4.9	5.7
Total	6.8	16.2	20.9
Natural Gas (Bcf)			
Developed	321.7	665.3	1,228.8
Undeveloped	79.5	461.3	510.9
Total	401.2	1,126.6	1,739.7
Equivalent reserves (Bcfe)			
Developed	354.7	733.1	1,320.0
Undeveloped	87.3	490.7	545.1
Total	442.0	1,223.8	1,865.1
Pre-tax present value, discounted at 10% (PV-10) (in millions)(1)			
Developed	$1,046.7	$1,353.7	$3,369.2
Undeveloped	201.9	252.3	576.7
Total	$1,248.6	$1,606.0	$3,945.9
Standardized Measure (in millions)	$ 823.3	$1,311.8	$3,118.9

(1) The PV-10 data does not include the effects of income taxes or derivative financial instruments, and is based on the following spot prices, in each case adjusted for historical differentials.

Date	Natural gas (per Mmbtu)	Oil (per Bbl)
December 31, 2005	$10.08	$61.03
December 31, 2006	5.64	60.82
December 31, 2007	6.80	95.92

We believe that PV-10 before income taxes, while not a financial measure in accordance with generally accepted accounting principles, is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions due to tax characteristics, which can differ significantly, among comparable companies. The Standardized Measure represents the PV-10 after giving effect to income taxes, and is calculated in accordance with SFAS No. 69. The following table provides a reconciliation of our PV-10 to our Standardized Measure:

(in millions)	At December 31, 2005	2006	2007
PV-10	$ 1,248.6	$1,606.0	$ 3,945.9
Future income taxes	(1,097.6)	(721.2)	(1,857.5)
Discount of future income taxes at 10% per annum	672.3	427.0	1,030.5
Standardized Measure	$ 823.3	$1,311.8	$ 3,118.9

The total reserve estimates presented as of December 31, 2005, 2006 and 2007 have been prepared by our internal engineers. These reserve estimates are reviewed and approved by senior engineering staff with final approval by the Vice President and Chief Operating Officer. During each of the years ended 2005, 2006 and 2007, we retained Lee Keeling to prepare an estimate of our Proved Reserves and future net cash flows attributable to our interests. The estimate of our PV-10 and Standardized Measure is based upon our estimate of future abandonment costs and the report on our Proved Reserves as prepared by Lee Keeling. Estimates of oil and natural gas reserves are projections based on a process involving an independent third party engineering firm's extensive visits, collection of any and all required geologic, geophysical, engineering and economic data, and such firm's complete external preparation of all required estimates and are forward-looking in nature. These reports rely upon various assumptions, including assumptions required by the SEC, such as constant oil and natural gas prices, operating expenses, capital expenditures, production and ad valorem taxes and availability of funds. These reports should not be construed as the current market value of our Proved Reserves. The process of estimating oil and natural gas reserves is also dependent on geological, engineering and economic data for each reservoir. Because of the uncertainties inherent in the interpretation of this data, we cannot ensure that the reserves will ultimately be realized. Our actual results could differ materially. See "Note 21. Supplemental information relating to oil and natural gas producing activities—continuing operations (unaudited)" of the notes to our consolidated financial statements for additional information regarding our oil and natural gas reserves and our Standardized Measure.

The Proved Reserve estimate prepared by Lee Keeling for the years ended 2005, 2006 and 2007 included a detailed review of all of our properties.

Lee Keeling also examined our estimates with respect to reserve categorization, using the definitions for Proved Reserves set forth in SEC Regulation S-X Rule 4-10(a) and SEC staff interpretations and guidance. In preparing an estimate of the reserves of future net cash flow attributable to our interest, Lee Keeling did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of the examination something came to the attention of Lee Keeling which brought into question the validity or sufficiency of any such information or data, Lee Keeling did not rely on such information or data until they had satisfactorily resolved their questions relating thereto or had independently verified such information or data. Lee Keeling determined that our estimates of reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(2) of SEC Regulation S-X. Lee Keeling issued an unqualified audit opinion on our Proved Reserves at December 31, 2007, based upon their evaluation. Their opinion concluded that our estimates of Proved Reserves were, in the aggregate, reasonable.

Our production, prices and expenses

The following table summarizes revenues (before cash settlements of derivative financial instruments), net production of oil and natural gas sold, average sales price per unit of oil and natural gas and costs and expenses associated with the production of oil and natural gas. This table includes information for acquisitions from the date of closing and excludes information with respect to the sale of our Canadian subsidiary in February 2005.

	Predecessor	Successor		
(in thousands, except production and per unit amounts)	For the 275 day period from January 1, 2005 to October 2, 2005	For the 90 day period from October 3, 2005 to December 31, 2005	Year ended December 31, 2006	Year ended December 31, 2007
Sales:				
Oil:				
Revenue(1)	$ 19,528	$ 6,666	$ 57,043	$117,073
Production sold (Mbbl)	375	116	916	1,645
Average sales price per Bbl(1)	$ 52.07	$ 57.47	$ 62.27	$ 71.17
Natural gas:				
Revenue(1)	$113,293	$63,395	$298,737	$728,987
Production sold (Mmcf)	15,490	5,112	44,123	111,419
Average sales price per Mcf(1)	$ 7.31	$ 12.40	$ 6.77	$ 6.54
Costs and expenses:				
Average production cost per Mcfe	$ 1.25	$ 1.54	$ 1.39	$ 1.41
General and administrative expense per Mcfe(2)	$ 5.04	$ 1.10	$ 0.83	$ 0.53
Depreciation, depletion and amortization per Mcfe	$ 1.39	$ 2.42	$ 2.74	$ 3.10

(1) Excludes the effects of derivative cash settlements and derivative financial instruments.

(2) General and administrative expense for the 275 day period from January 1, 2005 to October 2, 2005 includes $73.7 million of non-recurring bonus expense and non-cash stock-based compensation in connection with the Equity Buyout. Excluding these non-recurring items, the general and administrative expense would be $0.88 per Mcfe for the 275 day period from January 1, 2005 to October 2, 2005.

Our interest in productive wells

The following table quantifies as of the dates indicated information regarding productive wells (wells that are currently producing oil or natural gas or are capable of production), including temporarily shut-in wells. The number of total gross oil and natural gas wells excludes any multiple completions. Gross wells refers to the total number of physical wells that we hold any working interest in, regardless of our percentage interest. A net well is not a physical well, but is a concept that reflects the actual total working interests we hold in all wells. We compute the number of net wells we own by totaling the percentage interests we hold in all our gross wells.

	At December 31, 2007					
	Gross wells(1)			Net wells		
Areas	Oil	Gas	Total	Oil	Gas	Total
East Texas/North Louisiana	51	1,527	1,578	45.8	1,143.4	1,189.2
Appalachia	408	6,335	6,743	403.4	5,731.5	6,134.9
Mid-Continent	318	1,320	1,638	178.2	758.5	936.7
Permian	153	134	287	127.7	101.0	228.7
Rockies	44	22	66	34.8	18.8	53.6
Total	974	9,338	10,312	789.9	7,753.2	8,543.1

(1) As of December 31, 2007, we owned interests in 28 gross wells with multiple completions.

As of December 31, 2007, we were the operator of 9,273 gross (8,268.3 net) wells, which represented approximately 95% of our Proved Reserves as of December 31, 2007.

Our drilling activities

We intend to concentrate our drilling activity on lower risk, development-type properties. The number and types of wells we drill will vary depending on the amount of funds we have available for drilling, the cost of each well, the size of the fractional working interests in each well, the estimated recoverable reserves attributable to each well and accessibility to the well site.

The following tables summarize our approximate gross and net interests in the wells we drilled during the periods indicated and refers to the number of wells completed at any time during the period, regardless of when drilling was initiated. These tables exclude information with respect to Canada as a result of the sale of our Canadian subsidiary in February 2005.

	Development wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2005	104	2	106	101.1	1.5	102.6
Year ended December 31, 2006	366	5	371	298.2	2.3	300.5
Year ended December 31, 2007	487	7	494	394.7	4.6	399.3

	Exploratory wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2005	4	1	5	2.7	0.2	2.9
Year ended December 31, 2006	1	1	2	0.3	0.3	0.6
Year ended December 31, 2007	8	4	12	2.5	3.4	5.9

At December 31, 2007, we had 23 gross (20.6 net) wells being drilled and 42 gross (35.6 net) wells being completed.

Our developed and undeveloped acreage

Developed acreage are those acres spaced or assignable to producing wells. Undeveloped acreage are those acres that do not currently have completed wells capable of producing commercial quantities of oil or natural gas, regardless of whether the acreage contains Proved Reserves. The definitions of gross acres and net acres conform to how we determine gross wells and net wells. The following table sets forth our developed and undeveloped acreage at December 31, 2007:

	At December 31, 2007			
	Developed acreage		Undeveloped acreage	
Areas	Gross	Net	Gross	Net
East Texas/North Louisiana	171,883	137,636	156,658	140,844
Appalachia	420,256	394,381	442,933	420,692
Mid-Continent	348,308	202,502	30,324	19,267
Permian	38,717	23,707	32,808	26,644
Rockies	13,886	10,340	134,112	122,116
Total	993,050	768,566	796,835	729,563

The primary terms of our oil and natural gas leases expire at various dates, generally ranging from one to five years. Most of our undeveloped acreage is "held by production," which means that these leases are active as long as we produce oil or natural gas from the acreage. Upon ceasing production, these leases will expire. We have 100,454, 74,083 and 73,042 net acres with leases expiring in 2008, 2009 and 2010, respectively.

The undeveloped "held by production" acreage in many cases represents potential additional drilling opportunities through down spacing and drilling of proved undeveloped and unproved locations in the same formation(s) already producing in a given oil or natural gas field without the necessity of purchasing additional leases or producing properties.

Sales of producing properties and undeveloped acreage

We periodically review our properties to identify cost savings opportunities and divestiture candidates. We actively seek to dispose of properties with higher operating costs and properties that are not within our core geographic operating areas. We also seek to opportunistically divest properties in areas in which acquisitions and investment economics no longer meet our objectives, most notably evidenced by the sale of our Canadian subsidiary for $443.4 million, the sale of our Wattenberg Field operations in Colorado for $130.9 million in January 2007 and the sale of our Cement Field interest for $99.7 million on July 13, 2007. During the years ended December 31, 2005, 2006 and 2007, we received proceeds of $45.3 million, $5.2 million and $490.3 million, respectively, from the sale of properties in the United States.

Midstream operations

In connection with the Winchester acquisition, we acquired a 53-mile intrastate pipeline, or the TGG Pipeline, composed of 23 miles of 12-inch diameter and 30 miles of 16-inch diameter pipelines. The TGG Pipeline connects to several processing plants owned by others and interconnects 12 interstate pipeline markets. During 2007, we added 9 miles to this pipeline network, which now totals 62 miles. During December 2007, average throughput volume on the TGG Pipeline was 118 Mmcf/d with a total capacity of 175 Mmcf/d. Of the natural gas transported by the TGG Pipeline, approximately 20% represents production from our assets and approximately 80% represents production from third parties. We are presently expanding our TGG Pipeline in East Texas, adding 57 miles of 8-inch, 12-inch and 20-inch diameter pipe segments at a cost of approximately $37.6 million.

This expansion, which we expect to be fully operational in the second half of 2008, will allow 100 Mmcf/d of additional third party throughput.

In support to the above mentioned TGG Pipeline, we own and operate Talco Midstream Assets, a network of natural gas gathering systems comprised of approximately 550 miles of pipeline in our East Texas/North Louisiana area of operation, which gathers and transports natural gas to the TGG Pipeline and larger gathering systems and intrastate, interstate and local distribution pipelines owned by third parties. Of the 145 Mmcf/d of natural gas gathered and transported by this system, approximately 76% represents production from our assets and approximately 24% represents production from the assets of third parties. We transport natural gas from unaffiliated producers on our gathering and pipeline assets under fixed fee arrangements pursuant to which our gathering and transportation fee income represents an agreed rate per unit of throughput. The revenues we earn from these arrangements are directly related to the volume of natural gas that flows through our systems and are not directly dependent on commodity prices.

In connection with the Vernon Acquisition, we acquired a gathering system comprised of 167 miles of pipeline ranging in size from 3 inches to 16 inches in diameter. Since the acquisition, we have added 1 mile of 4-inch diameter pipeline. The pipeline connects to several processing plants and interconnects to five interstate pipeline markets. During December 2007, average throughput volume on the pipeline was 192 Mmcf/d with a total capacity of 420 Mmcf/d. Of all the natural gas transported by the gathering system, approximately 97% represents production from our assets and approximately 3% represents production from the assets of third parties.

Our principal customers

For the twelve months ended December 31, 2007, sales to a regulated natural gas utility company, Atmos Energy Marketing L.L.C. and its affiliates, and an independent oil and natural gas company, Anadarko and its affiliates, accounted for 20.0% and 12.1%, respectively, of total oil and natural gas revenues. For the twelve months ended December 31, 2006 and 2005 sales to one industrial customer, Alcan Rolled Products—Ravenswood, LLC, accounted for 4.9% and 10.1%, respectively, of total oil and natural gas revenues. We believe that the loss of any one customer would not have a material adverse effect on our results of operations or financial condition.

Competition

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and personnel substantially larger than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

We are also affected by competition for drilling rigs and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. We are unable to predict when, or if, such shortages may again occur or how they would affect our development and exploitation program.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights, and we cannot assure you that we will be able to compete satisfactorily. Many large oil companies have been actively marketing some of their existing producing properties for sale to independent producers. We regularly evaluate acquisition opportunities and submit bids as part of our growth strategy.

Applicable laws and regulations

General

The oil and gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect others in our industry with similar types, quantities and locations of production.

The following is a summary of the more significant existing environmental, safety and other laws and regulations to which our business operations are subject and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

Production Regulation

Our production operations are subject to a number of regulations at federal, state and local levels. These regulations require, among other things, permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

FERC Matters

The availability, terms and cost of downstream transportation significantly affect sales of natural gas, oil and NGLs. With regard to natural gas, the interstate transportation and sale for resale is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Since 1985, the FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to gas buyers and sellers on an open-access, non-discriminatory basis. Federal and state regulations govern the rates and terms for access to intrastate natural gas pipeline transportation, while states alone regulate natural gas gathering activities. With regard to oil and NGLs, the rates and terms and conditions of service for interstate transportation is regulated by FERC. Tariffs for such transportation must be just and reasonable and not unduly discriminatory. Oil and NGL transportation that is not federally regulated is left to state regulation.

Wholesale prices for natural gas, oil and NGLs are not currently regulated and are determined by the market. We cannot predict, however, whether new legislation to regulate the price of energy commodities might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties.

Under the Energy Policy Act of 2005, FERC possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation activities of non-interstate pipelines and other natural gas market participants. The Commodity Futures Trading Commission, or the CFTC, also holds authority to monitor certain segments of the physical and futures energy commodities market pursuant to the Commodity Exchange Act. With regard to our physical sales of natural gas, oil and NGLs, our gathering of any of these energy commodities, and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Federal, state or Indian oil and natural gas leases

In the event we conduct operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management, or BLM, or Minerals Management Service or other appropriate federal or state agencies.

Other regulatory matters relating to our pipeline and gathering system assets

The pipelines we use to gather and transport our oil and natural gas are subject to regulation by the Department of Transportation, or DOT, under the Hazardous Liquids Pipeline Safety Act of 1979, as amended, or the HLPSA, with respect to oil, and the Natural Gas Pipeline Safety Act of 1968, as amended, or the NGPSA, with respect to natural gas. The HLPSA and NGPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas and hazardous liquids pipeline facilities, including pipelines transporting crude oil. Where applicable, the HLPSA and NGPSA also require us and other pipeline operators to comply with regulations issued pursuant to these acts that are designed to permit access to and allow copying of records and to make certain reports available and provide information as required by the Secretary of Transportation.

The Pipeline Safety Act of 1992, as reauthorized and amended, mandates significant changes and new requirements in the way that the energy industry ensures the safety and integrity of its pipelines. The law applies to natural gas and hazardous liquids pipelines, including some natural gas gathering pipelines. Central to the law are the requirements it places on each pipeline operator to prepare and implement an "integrity management program." The Pipeline Safety Act of 1992 mandated a number of other requirements, including increased penalties for violations of safety standards and qualification programs for employees who perform sensitive tasks. The DOT has established a number of rules carrying out the provisions of this act. The Pipeline and Hazardous Materials Safety Administration of DOT, or the PHMSA, has established a new risk-based approach to determine which gathering pipelines are subject to regulation, and what safety standards regulated pipelines must meet. We could incur significant expenses as a result of these laws and regulations.

U.S. federal taxation

The federal government may propose tax initiatives that affect us. We are unable to determine what effect, if any, future proposals would have on product demand or our results of operations.

U.S. environmental regulations

The exploration, development and production of oil and natural gas, including the operation of saltwater injection and disposal wells, are subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, installing and operating oil and natural gas wells. Our domestic activities are subject to federal environmental laws and regulations, as they are amended from time to time, including, but not limited to:

- the Oil Pollution Act of 1990, or OPA;
- the Clean Water Act, or CWA;
- the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA;
- the Resource Conservation and Recovery Act, or RCRA;
- the Clean Air Act, or CAA; and
- the Safe Drinking Water Act, or SDWA.

Our domestic activities are also controlled by state regulations promulgated under comparable state statutes. We also are subject to regulations governing the handling, transportation, storage and disposal of naturally occurring radioactive materials that are found in our oil and natural gas operations. Administrative, civil and criminal fines and penalties may be imposed for non-compliance with environmental laws and regulations. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before undertaking certain of our activities, limit or prohibit other activities because of protected areas or species, can impose certain substantial liabilities for the clean-up of pollution, impose certain reporting requirements, regulate remedial plugging operations to prevent future contamination and can require substantial expenditures for compliance. We cannot predict what effect future regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

Under CWA, which was amended and augmented by OPA, our release or threatened release of oil or hazardous substances into or upon waters of the United States, adjoining shorelines and wetlands and offshore areas could result in our being held responsible for: (1) the costs of removing or remediating a release; (2) administrative, civil or criminal fines or penalties; or (3) OPA specified damages, such as loss of use, and natural resource damages. The extent of our liability could be extensive depending upon the circumstances of the release. Liability can be joint and several and without regard to fault. The CWA also may impose permitting requirements for certain discharges of pollutants and requirements to develop Spill Prevention Control and Countermeasure Plans and Facility Response Plans to address potential discharges of oil into or upon waters of the United States and adjoining shorelines. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters.

CERCLA, as amended, and comparable state statutes, also known as Superfund laws, can impose joint, several and retroactive liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on specified classes of persons for the release of a "hazardous substance" into the environment. In practice, under circumstances where harm is divisible, clean-up costs are usually allocated among the various responsible persons. These classes of persons, or so-called potentially responsible parties, or PRPs, include the current and certain past owners and operators of a facility where there has been a release or threat of release of a hazardous substance and persons who disposed of or arranged for the disposal of hazardous substances found at a site. CERCLA also authorizes the 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 PRPs the cost of such action. Liability can arise from conditions on properties where operations are conducted, even under circumstances where such operations were performed by third parties not under our control, and/or from conditions at third party disposal facilities where wastes from operations were sent. Although CERCLA currently exempts petroleum (including oil, natural gas and NGLs) from the definition of hazardous substance, some similar state statutes do not provide such an exemption. We cannot assure you that this exemption will be preserved in any future amendments of the act. Such amendments could have a material impact on our costs or operations. Additionally, our operations may involve the use or handling of other materials that may be classified as hazardous substances under CERCLA and similar state statutes. We may also be the owner or operator of sites on which hazardous substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA. We also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. Certain states have comparable statutes. In the event hazardous substance contamination is discovered at a site on which we are or have been an owner or operator, we could be liable for costs of investigation and remediation and natural resource damages.

RCRA and comparable state and local programs impose requirements on the management, treatment, storage and disposal of both hazardous and nonhazardous solid wastes. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under the properties we own or lease or the locations where such wastes have been taken for disposal. In addition, many of these properties have been owned or operated by third parties. We have not had control over such parties' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. We also generate hazardous and nonhazardous solid waste in our routine operations. While RCRA currently exempts drilling fluids, produced waters, and certain other wastes associated with the exploration, development and production of crude oil or natural gas from being regulated as hazardous wastes, from time to time, proposals have been made that would reclassify these oil and natural gas wastes as "hazardous wastes" under RCRA, which would make these solid wastes subject to much more stringent handling, transportation, storage, disposal and clean-up requirements. Adoption of these proposals could have a material impact on our operating costs. While state laws vary on this issue, state initiatives to further regulate oil and natural gas wastes could have a similar impact on our operations.

Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. The CAA and andogous state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Smaller sources may qualify for exemption from permit requirement of existing authorizations through issuance of permits by rule or general permits. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional operating permits. Federal and state laws designed to control hazardous (i.e., toxic) air pollutants might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require us to forgo construction, modification or operation of certain air emission sources.

Oil and natural gas exploration and production, and possibly other activities, have been conducted at a majority of our properties by previous owners and operators. Materials from these operations remain on some of the properties and in certain instances may require remediation. In some instances, we have agreed to indemnify the sellers of producing properties from whom we have acquired reserves against certain liabilities for environmental claims associated with the properties. We do not believe the costs to be incurred by us for compliance and remediating previously or currently owned or operated properties will be material, but we cannot guarantee that result.

If in the course of our routine oil and natural gas operations surface spills and leaks occur, including casing leaks of oil or other materials, we may incur penalties and costs for waste handling, remediation and third party actions for damages. Moreover, we are only able to directly control the operations of the wells that we operate. Notwithstanding our lack of control over wells owned by us but operated by others, the failure of the operator to comply with applicable environmental regulations may be attributable to us and may impose legal liabilities upon us.

There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act, or CZMA, was passed in 1972 to preserve and, where possible, restore the natural resources of the Nation's coastal zone. The CZMA provides for federal grants for state management programs that regulate land use, water use and coastal development. States, such as Texas, also have coastal management programs, which provide for, among other things, the coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development. Coastal management programs also may provide for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the state coastal management plan. In the event our activities trigger these programs, this review of agency rules and actions may impact other agency permitting and review activities, resulting in possible delays or restrictions of our activities and adding an additional layer of review to certain activities undertaken by us.

We do not anticipate that we will be required in the near future to expend amounts that are material in relation to our total capital expenditures program complying with current environmental laws and regulations. As these laws and regulations are frequently changed and are subject to interpretation, our assessment regarding the cost of compliance or the extent of liability risks may change in the future.

We are also unable to assure you that more stringent laws and regulations protecting the environment will not be adopted and that we will not incur material expenses in complying with environmental laws and regulations in the future. For instance, in response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to warming of the Earth's atmosphere, the current session of the U.S. Congress is considering climate change-related legislation to restrict greenhouse gas emissions. One bill recently approved by the U.S. Senate Environment and Public Works Committee, known as the Lieberman-Warner Climate Security Act or S.2191, would require a 70% reduction in emissions of greenhouse gases from sources within the United States between 2012 and 2050. The Lieberman-Warner bill proposes a "cap and trade" scheme of regulation of greenhouse gas emissions—a ban on emissions above a defined reducing annual cap. Covered parties will be authorized to emit greenhouse emissions through the acquisition and subsequent surrender of emission allowances that may be traded or acquired on the open market. Debate and a possible vote on this bill by the full Senate are anticipated to occur before mid-year 2008. In addition, at least 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of fuels (*e.g.*, oil or natural gas) we produce. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may regulate carbon dioxide and other greenhouse gas emissions from mobile sources such as cars and trucks, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The EPA has indicated that it will issue a rulemaking notice to address carbon dioxide and other greenhouse gas emissions from vehicles and automobile fuels, although the date for issuance of this notice has not been finalized. The Court's holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources under certain CAA programs. New federal or state laws requiring adoption of a stringent greenhouse gas control program or imposing restrictions on emissions of carbon dioxide in areas of the United States in which we conduct business could adversely affect our cost of doing business and demand for the oil and gas we produce.

If substantial liabilities to third parties or governmental entities are incurred, the payment of such claims may reduce or eliminate the funds available for project investment or result in loss of our properties. Although we maintain insurance coverage we consider to be customary in the industry, we are not fully insured against all of these risks, either because insurance is not available or because of high premiums. Accordingly, we may be subject to liability or may lose substantial portions of properties due to hazards that cannot be insured against or have not been insured against due to prohibitive premiums or for other reasons. The imposition of any of these liabilities or compliance obligations on us may have a material adverse effect on our financial condition and results of operations.

OSHA and other regulations

We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

Anti-terrorism security measures.

Our operations and the operations of the natural gas and oil industry in general may be subject to laws and regulations regarding the security of industrial facilities, including natural gas and oil facilities. The Department of Homeland Security Appropriations Act of 2007 required the Department of Homeland Security, or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS issued an interim final rule, known as the Chemical Facility Anti-Terrorism Standards interim rule, in April 2007 regarding risk-based performance standards to be attained pursuant to the act and on November 20, 2007 further issued an Appendix A to the interim rule that established the chemicals of interest and their respective threshold quantities that may trigger compliance with these interim rules. Facilities possessing greater than threshold levels of these chemicals of interest were required to prepare and submit to the DHS in January 2008 initial screening surveys that the agency would use to determine whether the facilities presented a high level of security risk. Covered facilities that are determined by DHS to pose a high level of security risk will be notified by DHS and will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information. We have not yet determined the extent to which our facilities are subject to coverage under the interim rules or the associated costs to comply, but it is possible that such costs could be substantial.

Title to our properties

When we acquire developed properties, we conduct a title investigation. However, when we acquire undeveloped properties, as is common industry practice, we usually conduct little or no investigation of title other than a preliminary review of local mineral records. We do conduct title investigations and, in most cases, obtain a title opinion of local counsel before we begin drilling operations. We believe that the methods we utilize for investigating title prior to acquiring any property are consistent with practices customary in the oil and natural gas industry and that our practices are adequately designed to enable us to acquire good title to properties. However, some title risks cannot be avoided, despite the use of customary industry practices.

Our properties are generally burdened by:

- customary royalty and overriding royalty interests;
- liens incident to operating agreements; and
- liens for current taxes and other burdens and minor encumbrances, easements and restrictions.

We believe that none of these burdens either materially detract from the value of our properties or materially interfere with property used in the operation of our business. Substantially all of our properties are pledged as collateral under our credit agreements.

Our employees

As of December 31, 2007, we employed 689 persons of which 406 were involved in field operations and 283 were engaged in technical, office or administrative activities. None of our employees are represented by unions or covered by collective bargaining agreements. To date, we have not experienced any strikes or work stoppages due to labor problems, and we consider our relations with our employees to be good. We also utilize the services of independent consultants on a contract basis.

Forward-looking statements

This Annual Report on Form 10-K contains forward-looking statements, as defined in Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. These forward-looking statements relate to, among other things, the following:

- our future financial and operating performance and results;
- our business strategy;
- market prices;
- our future use of derivative financial instruments; and
- our plans and forecasts.

We have based these forward-looking statements on our current assumptions, expectations and projections about future events.

We use the words "may," "expect," "anticipate," "estimate," "believe," "continue," "intend," "plan," "budget" and other similar words to identify forward-looking statements. You should read statements that contain these words carefully because they discuss future expectations, contain projections of results of operations or of our financial condition and/or state other "forward-looking" information. We do not undertake any obligation to update or revise publicly any forward-looking statements, except as required by law. These statements also involve risks and uncertainties that could cause our actual results or financial condition to materially differ from our expectations in this Annual Report on Form 10-K, including, but not limited to:

- fluctuations in prices of oil and natural gas;
- imports of foreign oil and natural gas, including liquified natural gas;
- future capital requirements and availability of financing;
- estimates of reserves and economic assumptions used in connection with our acquisitions;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- risks associated with the operation of natural gas pipelines and gathering systems;
- discovery, acquisition, development and replacement of oil and natural gas reserves;
- cash flow and liquidity;
- impacts of our Private Placement of 7.0% Preferred Stock and the Hybrid Preferred Stock and the impact of dividends on our capital resources and liquidity;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- marketing of oil and natural gas;
- developments in oil-producing and natural gas-producing countries;
- title to our properties;
- litigation;
- competition;
- general economic conditions, including costs associated with drilling and operations of our properties;
- governmental regulations;
- receipt of amounts owed to us by purchasers of our production and counterparties to our derivative financial instruments;
- decisions about derivative financial instruments;
- events similar to those of September 11, 2001;
- actions of third party co-owners of interests in properties in which we also own an interest;
- fluctuations in interest rates; and
- our ability to effectively integrate companies and properties that we acquire.

We believe that it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. You are cautioned not to place undue reliance on a forward-looking statement. When considering our forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Annual Report on Form 10-K. The risk factors noted in this Annual Report on Form 10-K and other factors noted throughout this Annual Report on Form 10-K provide examples of risks, uncertainties and events that may cause our actual results to differ materially from those contained in any forward-looking statement. Please see "Item 1A. Risk factors" for a discussion of certain risks of our business and an investment in our common stock.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil and natural gas. Declines in oil or natural gas prices may materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower oil or natural gas prices may also reduce the amount of oil or natural gas that we can produce economically. A decline in oil and/or natural gas prices could have a material adverse effect on the estimated value and estimated quantities of our oil and natural gas reserves, our ability to fund our operations and our financial condition, cash flow, results of operations and access to capital. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

Glossary of selected oil and natural gas terms

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and this Annual Report on Form 10-K.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Btu. British thermal unit, which is the heat required to raise the temperature of a one pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Commercial Well; Commercially Productive Well. An oil and natural gas well which produces oil and natural gas in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Completion. The installation of permanent equipment for the production of oil or natural gas, or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Well. A well drilled within the proved area of an oil or natural gas reservoir, or which extends a proved reservoir, to the depth of a stratigraphic horizon known to be productive.

Downspacing Wells. Additional wells drilled between known producing wells to better exploit the reservoir.

Dry Hole; Dry Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Exploitation. The continuing development of a known producing formation in a previously discovered field. To maximize the ultimate recovery of oil or natural gas from the field by development wells, secondary recovery equipment or other suitable processes and technology.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Full Cost Pool. The full cost pool consists of all costs associated with property acquisition, exploration, and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration and development activities are included. Any costs related to production, general corporate overhead or similar activities are not included.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal Wells. Wells which are drilled at angles greater than 70 degrees from vertical.

Infill drilling. Drilling of a well between known producing wells to better exploit the reservoir.

Mbbl. One thousand stock tank barrels.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Mmbbl. One million stock tank barrels.

Mmbtu. One million British thermal units.

Mmcf. One million cubic feet of natural gas.

Mmcf/d. One million cubic feet of natural gas per day.

Mmcfe. One million cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Mmcfe/d. One million cubic feet equivalent per day calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Mmmbtu. One billion British thermal units.

NYMEX. New York Mercantile Exchange.

NGLs. The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

Overriding royalty interest. An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Present value of estimated future net revenues or PV-10. The present value of estimated future net revenues is an estimate of future net revenues from a property at the date indicated, without giving effect to derivative financial instrument activities, after deducting production and ad valorem taxes, future capital costs, abandonment costs and operating expenses, but before deducting federal income taxes. The future net revenues have been discounted at an annual rate of 10% to determine their "present value." The present value is shown to indicate the effect of time on the value of the net revenue stream and should not be construed as being the fair market value of the properties. Estimates have been made using constant oil, natural gas and NGL prices and operating costs at the date indicated, at its acquisition date, or as otherwise indicated. We believe that the present value of estimated future net revenues before income taxes, while not a financial measure in accordance with GAAP, is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially.

Productive Well. A productive well is a well that is not a dry well.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Reserves. 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, i.e., 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 based upon future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of Proved Reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved Undeveloped Reserves. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved Reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Recompletion. An operation within an existing well bore to make the well produce oil and/or gas from a different, separately producible zone other than the zone from which the well had been producing.

Reserve Life. The estimated productive life, in years, of a proved reservoir based upon the economic limit of such reservoir producing hydrocarbons in paying quantities assuming certain price and cost parameters. For purposes of this Annual Report on Form 10-K, reserve life is calculated by dividing the Proved Reserves (on a Mmcfe basis) at the end of the period by production volumes for the previous 12 months.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

Royalty interest. An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Standardized Measure of discounted future net cash flows or the Standardized Measure. Under the Standardized Measure, future cash flows are estimated by applying year-end prices, adjusted for fixed and determinable escalations, to the estimated future production of year-end Proved Reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the associated properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate to arrive at the Standardized Measure.

Stock tank barrel. 42 U.S. gallons liquid volume.

Tcf. One trillion cubic feet of natural gas.

Tcfe. One trillion cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Undeveloped Acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains Proved Reserves.

3-D seismic. Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct activities on the property and a share of production.

Workovers. Operations on a producing well to restore or increase production.

Available information

We make our filings with the SEC available, free of charge, on our website at *www.excoresources.com* as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC.

ITEM 1A. RISK FACTORS

The risk factors noted in this section and other factors noted throughout this Annual Report on Form 10-K, including those risks identified in "Item 7. Management's discussion and analysis of financial condition and results of operations," describe examples of risks, uncertainties and events that may cause our actual results to differ materially from those contained in any forward-looking statement.

If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual outcomes may vary materially from those included in this Annual Report on Form 10-K.

Risks relating to our business

Fluctuations in oil and natural gas prices, which have been volatile at times, may adversely affect our revenues as well as our ability to maintain or increase our borrowing capacity, repay current or future indebtedness and obtain additional capital on attractive terms.

Our future financial condition, access to capital, cash flow and results of operations depend upon the prices we receive for our oil and natural gas. We are particularly dependent on prices for natural gas. As of December 31, 2007, 93.3% of our Proved Reserves were natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. Factors that affect the prices we receive for our oil and natural gas include:

- the level of domestic production;
- the availability of imported oil and natural gas;
- political and economic conditions and events in foreign oil and natural gas producing nations, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the cost and availability of transportation and pipeline systems with adequate capacity;
- the cost and availability of other competitive fuels;
- fluctuating and seasonal demand for oil and natural gas;
- conservation and the extent of governmental price controls and regulation of production;
- weather;
- foreign and domestic government relations; and
- overall economic conditions.

In the past, prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue. During 2007, the NYMEX price for natural gas has fluctuated from a high of $8.64 per Mmbtu to a low of $5.38 per Mmbtu, while the NYMEX West Texas Intermediate crude oil price ranged from a high of $98.18 per barrel to a low of $50.48 per barrel. For the five years ended December 31, 2007, the NYMEX Henry Hub natural gas price ranged from a high of $15.38 per Mmbtu to a low of $4.20 per Mmbtu, while the NYMEX West Texas Intermediate crude oil price ranged from a high of $98.18 per barrel to a low of $25.24 per barrel. On December 31, 2007, the spot market price for natural gas at Henry Hub was $6.80 per Mmbtu, a 21% increase from December 31, 2006. In 2007, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were $71.17 per Bbl and $6.54 per Mcf compared with 2006 prices of $62.27 per Bbl and $6.77, respectively.

Our revenues, cash flow and profitability and our ability to maintain or increase our borrowing capacity, to repay current or future indebtedness and to obtain additional capital on attractive terms depend substantially upon oil and natural gas prices.

Changes in the differential between NYMEX or other benchmark prices of oil and natural gas and the reference or regional index price used to price our actual oil and natural gas sales could have a material adverse effect on our results of operations and financial condition.

The reference or regional index prices that we use to price our oil and natural gas sales sometimes reflect a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we reference in our sales contracts is called a differential. We cannot accurately predict oil and natural gas differentials. Increases in the differential between the benchmark price for oil and natural gas and the reference or regional index price we reference in our sales contracts could have a material adverse effect on our results of operations and financial condition.

Our use of derivative financial instruments may cause us to forego additional future profits or result in our making cash payments.

To reduce our exposure to changes in the prices of oil and natural gas, we have entered into and may in the future enter into derivative financial instrument arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our derivative financial instruments are subject to mark-to-market accounting treatment. The change in the fair market value of these instruments is reported in our statement of operations each quarter, which typically result in significant variability in our net income. Derivative financial instruments expose us to the risk of financial loss and may limit our ability to benefit from increases in oil and natural gas prices in some circumstances, including the following:

- the counterparty to the derivative financial instrument contract may default on its contractual obligations to us;
- there may be a change in the expected differential between the underlying price in the derivative financial instrument agreement and actual prices received; or
- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments.

Our use of derivative financial instruments could have the effect of reducing our revenues and the value of our common stock. During the year ended December 31, 2006, we received cash settlements from our derivative financial instrument contracts totaling $29.4 million. During the year ended December 31, 2007, we received cash settlements from our derivative financial instrument contracts totaling $108.4 million. For the year ended December 31, 2007, a $1.00 increase in the average commodity price per Mcfe would have resulted in an increase in cash settlement payments (or a decrease in settlements received) of approximately $109.3 million. As of December 31, 2007, the net unrealized losses on our derivative financial instrument contracts was $81.6 million. The ultimate settlement amount of these unrealized derivative financial instrument contracts is dependent on future commodity prices. In connection with the TXOK, Winchester, Vernon and Southern Gas acquisitions, we assumed additional derivative financial instruments covering a significant portion of estimated future production. We may incur significant unrealized losses in the future from our use of derivative financial instruments to the extent market prices increase and our derivatives contracts remain in place. See "Item 7. Management's discussion and analysis of financial condition and results of operations—Liquidity, capital resources and capital commitments—Derivative financial instruments."

We will face risks associated with our recent acquisitions relating to difficulties in integrating operations, potential disruptions of operations, and related negative impact on earnings.

The TXOK, Winchester, Vernon and Southern Gas acquisitions represented a significant increase in our reserves and production. These acquisitions are the largest acquisitions that we have completed to date.

These acquisitions present significant integration challenges for us. In addition to the other general acquisition risks described elsewhere in this section, the magnitude of these acquisitions could strain our managerial, financial, accounting, technical, operational and administrative resources, disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards as well as our internal controls and procedures. We may not be successful in overcoming these risks or any other problems encountered in connection with these acquisitions, all of which could negatively impact our results of operations and our ability to generate cash needed to service our debt and fund our capital program and other working capital requirements.

We incurred a substantial amount of indebtedness to fund our 2006 and 2007 acquisitions, which may adversely affect our cash flow and our ability to operate our business, remain in compliance with debt covenants and make payments on our debt.

In connection with our 2006 and 2007 acquisitions, we have increased our consolidated indebtedness from $461.8 million at December 31, 2005 to $2.1 billion at December 31, 2007. To service this indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or debt capital or restructure our debt. None of these remedies may, if necessary, be effected on commercially reasonable terms, or at all. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt under our credit facilities, which could cause us to default on our obligations and could impair our liquidity.

We may be unable to acquire or develop additional reserves, which would reduce our revenues and access to capital.

Our success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are profitable to produce. Factors that may hinder our ability to acquire additional oil and natural gas reserves include competition, access to capital, prevailing oil and natural gas prices and the number and attractiveness of properties for sale. If we are unable to conduct successful development activities or acquire properties containing Proved Reserves, our total Proved Reserves will generally decline as a result of production. Also, our production will generally decline. In addition, if our reserves and production decline, then the amount we are able to borrow under our credit agreements will also decline. We may be unable to locate additional reserves, drill economically productive wells or acquire properties containing Proved Reserves.

We may not identify all risks associated with the acquisition of oil and natural gas properties, and any indemnifications we receive from sellers may be insufficient to protect us from such risks, which may result in unexpected liabilities and costs to us.

Generally, it is not feasible for us to review in detail every individual property involved in an acquisition. Our business strategy focuses on acquisitions of producing oil and natural gas properties. Any future acquisitions will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards, potential tax and Employee Retirement Security Act, or ERISA, liabilities, and other liabilities and other similar factors. Ordinarily, our review efforts are focused on the higher-valued properties. For example, in the TXOK, Winchester, Vernon and Southern Gas acquisitions we did not review title or production data for, or physically inspect, every well we acquired. Even a detailed review of properties and records may not reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not inspect every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we inspect a well. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition and results of operations.

Even if we are able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnity against all or part of these problems. Even if a seller agrees to provide indemnity, the indemnity may not be fully enforceable and may be limited by floors and caps on such indemnity. The indemnifications we received in the TXOK, Winchester, Vernon and Southern Gas acquisitions are subject to floors, caps and time limitations and do not cover all these types of risks.

We may be unable to obtain additional financing to implement our growth strategy.

The growth of our business will require substantial capital on a continuing basis. Due to the amount of debt we have incurred, it may be difficult for us in the foreseeable future to obtain additional debt financing on an unsecured basis or to obtain additional secured financing other than purchase money indebtedness. If we are unable to obtain additional capital on satisfactory terms and conditions, we may lose opportunities to acquire oil and natural gas properties and businesses and, therefore, unable to implement our growth strategy.

We may not be successful in managing our growth, which could adversely affect our operations and net revenues.

The pursuit of additional acquisitions is a key part of our strategy. We face challenges in growing our managerial, financial, accounting, technical, operational and administrative resources to keep up with the pace of the growth of our business and our significant corporate transactions such as the TXOK, Winchester, Vernon and Southern Gas acquisitions. For example, our rapid growth and significant transactions over the past two years have strained, and could continue to strain, our financial, tax and accounting staff. The size and scope of our business from an operational, personnel, financial reporting and accounting perspective have substantially increased due to the TXOK, Winchester, Vernon and Southern Gas acquisitions. Our growth could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards as well as internal controls and procedures. Failure to manage our growth successfully could adversely affect our operations and net revenues through increased operating costs and revenues that do not meet our expectations, as well as adversely affect our ability to satisfy our disclosure and other obligations. We may also be unable to successfully integrate acquired oil and natural gas properties into our operations or achieve desired profitability.

If we are unable to successfully prevent or address material weaknesses in our internal control over financial reporting, or any other control deficiencies, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other requirements may be adversely affected.

As of December 31, 2007, we are required to comply with Section 404 of the Sarbanes-Oxley Act of 2002. Prior to December 31, 2007, we were not required to make an assessment of the effectiveness of our internal control over financial reporting for that purpose. However, in connection with the 2004 and the 2005 audits of the financial statements of EXCO Resources, we reported a material weakness in Item 9A of our Annual Report on Form 10-K. In addition, prior to the quarter ended September 30, 2006, our management concluded that our disclosure controls and procedures were not effective due to a material weakness relating to accounting for income taxes. Although we remediated this material weakness, we may identify additional material weaknesses or other deficiencies in our internal control over financial reporting in the future.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim financial statements will not be prevented or detected on a timely basis.

We will continue to monitor the effectiveness of these and other processes, procedures and controls and will make any further changes management determines appropriate, including to effect compliance with Section 404 of the Sarbanes-Oxley Act of 2002.

Any material weaknesses or other deficiencies in our internal control over financial reporting may affect our ability to comply with SEC reporting requirements and the NYSE listing standards or cause our financial statements to contain material misstatements, which could negatively affect the market price and trading liquidity of our common stock, cause investors to lose confidence in our reported financial information, as well as subject us to civil or criminal investigations and penalties.

There are inherent limitations in all internal control systems over financial reporting, and misstatements due to error or fraud may occur and not be detected.

While we have taken actions designed to address compliance with the internal control, disclosure control and other requirements of the Sarbanes-Oxley Act of 2002 and the rules and regulations promulgated by the SEC implementing these requirements, there are inherent limitations in our ability to control all circumstances. Our management, including our Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, does not expect that our internal controls and disclosure controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Further, controls can be circumvented by individual acts of some persons, by collusion of two or more persons, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, a control may be inadequate because of changes in conditions, such as growth of the company or increased transaction volume, or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

We may encounter obstacles to marketing our oil and natural gas, which could adversely impact our revenues.

Our ability to market our oil and natural gas production will depend upon the availability and capacity of natural gas gathering systems, pipelines and other transportation facilities. We are primarily dependent upon third parties to transport our products. Transportation space on the gathering systems and pipelines we utilize is occasionally limited or unavailable due to repairs, outages caused by accidents or other events, or improvements to facilities or due to space being utilized by other companies that have priority transportation agreements. We experienced production curtailments in the Appalachian Basin during 2005, 2006 and 2007 resulting from capacity restraints and short term shutdowns of certain pipelines for maintenance purposes. Our access to transportation options can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. These factors and the availability of markets are beyond our control. If market factors dramatically change, the impact on our revenues could be substantial and could adversely affect our ability to produce and market oil and natural gas, the value of our common stock and our ability to pay dividends on our company stock.

There are risks associated with our drilling activity that could impact the results of our operations.

Our drilling involves numerous risks, including the risk that we will not encounter commercially productive oil or natural gas reservoirs. We must incur significant expenditures to identify and acquire properties and to drill and complete wells. Additionally, seismic technology does not allow us to know conclusively prior to drilling a well that oil or natural gas is present or economically producible. The costs of drilling and completing wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, weather conditions and shortages or delays in the delivery of equipment. We have experienced some delays in contracting for drilling rigs and increasing costs to drill wells. All of these risks could adversely affect our results of operations and financial condition.

We may not correctly evaluate reserve data or the exploitation potential of properties as we engage in our acquisition, development, and exploitation activities.

Our future success will depend on the success of our acquisition, development, and exploitation activities. Our decisions to purchase, develop or otherwise exploit properties or prospects will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Our estimates regarding the increase in our reserves and production resulting from the Winchester, TXOK, Vernon and Southern Gas acquisitions may prove to be incorrect, which could significantly reduce our ability to generate cash needed to service our debt and fund our capital program and other working capital requirements.

We cannot control the development of the properties we own but do not operate, which may adversely affect our production, revenues and results of operations.

As of December 31, 2007, third parties operate wells that represent approximately 5% of our Proved Reserves. As a result, the success and timing of our drilling and development activities on those properties depend upon a number of factors outside of our control, including:

- the timing and amount of capital expenditures;
- the operators' expertise and financial resources;
- the approval of other participants in drilling wells; and
- the selection of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted on a timely basis, we may be unable to increase our production or offset normal production declines, which may adversely affect our production, revenues and results of operations.

Our estimates of oil and natural gas reserves involve inherent uncertainty, which could materially affect the quantity and value of our reported reserves and our financial condition.

Numerous uncertainties are inherent in estimating quantities of proved oil and natural gas reserves, including many factors beyond our control. This Annual Report on Form 10-K contains estimates of our proved oil and natural gas reserves and the PV-10 and Standardized Measure of our proved oil and natural gas reserves. These estimates are based upon reports of our own engineers and our independent petroleum engineers. These reports rely upon various assumptions, including assumptions required by the SEC as to constant oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. These estimates should not be construed as the current market value of our estimated Proved Reserves. The process of estimating oil and natural gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir. As a result, the estimates are inherently imprecise evaluations of reserve quantities and future net revenue. Our actual future production, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from those we have assumed in the estimates. Any significant variance in our assumptions could materially affect the quantity and value of reserves, the amount of PV-10 and Standardized Measure described in this Annual Report on Form 10-K, and our financial condition. In addition, our reserves or PV-10 and Standardized Measure may be revised downward or upward, based upon production history, results of future exploitation and development activities, prevailing oil and natural gas prices and other factors. A material decline in prices paid for our production can adversely impact the estimated volumes of our reserves. Similarly, a decline in market prices for oil or natural gas may adversely affect our PV-10 and Standardized Measure. Any of these negative effects on our reserves or PV-10 and Standardized Measure may decrease the value of our common stock.

We are exposed to operating hazards and uninsured risks that could adversely impact our results of operations and cash flow.

Our operations are subject to the risks inherent in the oil and natural gas industry, including the risks of:

- fires, explosions and blowouts;
- pipe failures;
- abnormally pressured formations; and
- environmental accidents such as oil spills, gas leaks, ruptures or discharges of toxic gases, brine or well fluids into the environment (including groundwater contamination).

We have in the past experienced some of these events during our drilling operations. These events may result in substantial losses to us from:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- environmental clean-up responsibilities;
- regulatory investigation;
- penalties and suspension of operations; or
- attorneys' fees and other expenses incurred in the prosecution or defense of litigation.

As is customary in our industry, we maintain insurance against some, but not all, of these risks. Our insurance may not be adequate to cover these potential losses or liabilities. Furthermore, insurance coverage may not continue to be available at commercially acceptable premium levels or at all. Due to cost considerations, from time to time we have declined to obtain coverage for certain drilling activities and have therefore been restricted from conducting these types of drilling activities during the period we were uninsured. We do not carry business interruption insurance. Losses and liabilities arising from uninsured or under-insured events could require us to make large unbudgeted cash expenditures that could adversely impact our results of operations and cash flow.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas development and production operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to comply with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, production and sale of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition and results of operations. Please see "Business—Applicable laws and regulations" for a description of the laws and regulations that affect us.

Our business exposes us to liability and extensive regulation on environmental matters, which could result in substantial expenditures.

Our operations are subject to numerous U.S. federal, state and local laws and regulations relating to the protection of the environment, including those governing the discharge of materials into the water and air, the generation, management and disposal of hazardous substances and wastes and the clean-up of contaminated sites. We could incur material costs, including clean-up costs, fines and civil and criminal sanctions and third-party claims for property damage and personal injury as a result of violations of, or liabilities under, environmental laws and regulations. Such laws and regulations not only expose us to liability for our own activities, but may also expose us to liability for the conduct of others or for actions by us that were in compliance with all applicable laws at the time those actions were taken. In addition, we could incur substantial expenditures complying with environmental laws and regulations, including future environmental laws and regulations which may be more stringent.

Our business substantially depends on Douglas H. Miller, our Chief Executive Officer.

We are substantially dependent upon the skills of Mr. Douglas H. Miller. Mr. Miller has extensive experience in acquiring, financing and restructuring oil and natural gas companies. We do not have an employment agreement with Mr. Miller or maintain key man insurance. The loss of the services of Mr. Miller could hinder our ability to successfully implement our business strategy.

We may have write-downs of our asset values, which could negatively affect our results of operations and net worth.

We follow the full cost method of accounting for our oil and natural gas properties. Depending upon oil and natural gas prices in the future, and at the end of each quarterly and annual period when we are required to test the carrying value of our assets using full cost accounting rules, we may be required to write-down the value of our oil and natural gas properties if the present value of the after-tax future cash flows from our oil and natural gas properties falls below the net book value of these properties. We have in the past experienced ceiling test write-downs with respect to our oil and natural gas properties. Future non-cash ceiling test write-downs could negatively affect our results of operations and net worth.

We also test goodwill for impairment annually or when circumstances indicate that an impairment may exist. If the book value of our reporting units exceeds the fair value of those reporting units, an impairment charge will occur, which could negatively impact our net worth.

We may experience a financial loss if any of our significant customers fail to pay us for our oil or natural gas.

Our ability to collect the proceeds from the sale of oil and natural gas from our customers depends on the payment ability of our customer base, which includes several significant customers. If any one or more of our significant customers fails to pay us for any reason, we could experience a material loss. In addition, in recent years, a number of energy marketing and trading companies have discontinued their marketing and trading operations, which has significantly reduced the number of potential purchasers for our oil and natural gas production. This reduction in potential customers has reduced market liquidity and, in some cases, has made it difficult for us to identify creditworthy customers. We also sell a portion of our natural gas directly to end users. We may experience a material loss as a result of the failure of our customers to pay us for prior purchases of our oil or natural gas.

We may experience a decline in revenues if we lose one of our significant customers.

For the twelve months ended December 31, 2007, sales to a regulated natural gas utility company, Atmos Energy Marketing L.L.C. and its affiliates, and an independent oil and natural gas company, Anadarko and its affiliates, accounted for 20.0% and 12.1%, respectively, of total oil and natural gas revenues. For the twelve months ended December 31, 2006 and 2005 sales to one industrial customer, Alcan Rolled Products—Ravenswood, LLC, accounted for 4.9% and 10.1%, respectively, of total oil and natural gas revenues. In 2007, our top four customers accounted for approximately 43.5% of our total oil and natural gas revenues. To the extent any significant customer reduces the volume of its natural gas purchases from us, we could experience interruption in sales of, or a lower price for, our oil and natural gas.

Competition in our industry is intense and we may be unable to compete in acquiring properties, contracting for drilling equipment and hiring experienced personnel.

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have financial and technical resources and personnel substantially larger than ours. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit. The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. We may experience difficulties in obtaining drilling rigs and other services in certain areas as well as an increase in the cost for these services and related material and equipment. We are unable to predict how such shortages and price increases will affect our development and exploitation program. Competition has also been strong in hiring experienced personnel, particularly in petroleum engineering, geoscience, accounting and financial reporting, tax and land professions. In addition, competition is strong for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights. We are often outbid by competitors in our attempts to acquire properties or companies. All of these challenges could make it more difficult to execute our growth strategy and increase our costs.

The success of our natural gas gathering and transportation business depends upon our ability to continually obtain new sources of natural gas supply, and any decrease in supplies of natural gas could reduce our transportation revenues.

Our gathering and transportation pipelines are connected to natural gas reserves and wells, for which the production will naturally decline over time, which means that our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on our pipelines, we must continually obtain new natural gas supplies. We may not be able to obtain additional third party contracts for natural gas supplies. The primary factors affecting our ability to connect new supplies of gas and attract new customers to our gathering and transportation pipelines include: (i) the level of successful drilling activity near our gathering systems and (ii) our ability to compete for the commitment of such additional volumes to our systems.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. We have no control over the level of drilling activity in the areas of our operations other than our own drilling, the amount of reserves underlying the wells or the rate at which production from a well will decline. In addition, we have no control over third party producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations and the availability and cost of capital.

We face strong competition in acquiring new natural gas supplies. Competitors to our pipeline operations include major interstate and intrastate pipelines, and other natural gas gatherers. Competition for natural gas supplies is primarily based on the location of pipeline facilities, pricing arrangements, reputation, efficiency, flexibility and reliability. Many of our competitors have greater financial resources than we do.

If we are unable to maintain or increase the throughput on our gathering and transportation pipelines because of decreased drilling activity in the areas in which we operate or because of an inability to connect new supplies of gas and attract new customers to our gathering and transportation pipelines, then our business and financial results could be materially adversely affected.

If third-party pipelines and other facilities interconnected to our gathering and transportation pipelines become unavailable to transport or process natural gas, our revenues and cash flow could be adversely affected.

We depend upon third party pipelines and other facilities that provide delivery options from our transportation and gathering pipelines for the benefit of our customers. All of the natural gas transported by our pipelines must be processed by processing plants before delivery into a pipeline for natural gas. We own only one processing plant that treats certain natural gas products. If the processing plants to which we deliver natural gas were to become temporarily or permanently unavailable for any reason, or if throughput were reduced because of testing, line repair, damage to pipelines, reduced operating pressures, lack of capacity or other causes, our customers would be unable to deliver natural gas to end markets. Either of such events could materially and adversely affect our business, results of operations and financial condition.

We do not own all of the land on which our transportation and gathering pipelines and gathering system are located, which could disrupt our operations.

We do not own all of the land on which our transportation and gathering pipelines have been constructed, and we are therefore subject to the possibility of increased costs to retain necessary land use. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations and financial condition.

Risks relating to our indebtedness

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business, remain in compliance with debt covenants and make payments on our debt.

As of December 31, 2007, we had approximately $2.1 billion of indebtedness, including $1.6 billion of indebtedness which is subject to variable interest rates. Our total interest expense on an annual basis is approximately $131.1 million and would change by approximately $16.4 million for every 1% change in interest rates.

Our level of debt could have important consequences, including the following:

- it may be more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the Indenture governing our senior notes and the agreements governing our other indebtedness;
- we may have difficulty borrowing money in the future for acquisitions, capital expenditures or to meet our operating expenses or other general corporate obligations;
- the amount of our interest expense may increase because certain of our borrowings are at variable rates of interest;
- we will need to use a substantial portion of our cash flows to pay principal and interest on our debt, which will reduce the amount of money we have for operations, working capital, capital expenditures, expansion, acquisitions or general corporate or other business activities;
- we may have a higher level of debt than some of our competitors, which may put us at a competitive disadvantage;
- we may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially declines in oil and natural gas prices; and
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will be unable to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our earnings will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we do not have enough money to service our debt, we may be required but unable to refinance all or part of our existing debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all. Further, failing to comply with the financial and other restrictive covenants in our credit agreements and the Indenture governing our senior notes could result in an event of default, which could adversely affect our business, financial condition and results of operations.

We may incur substantially more debt, which may intensify the risks described above, including our ability to service our indebtedness.

Together with our subsidiaries, we may incur substantially more debt in the future in connection with our acquisition, development, exploitation and exploration of oil and natural gas producing properties. The restrictions in our debt agreements on our incurrence of additional indebtedness are subject to a number of qualifications and exceptions, and under certain circumstances, indebtedness incurred in compliance with these restrictions could be substantial. Also, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness. To the extent new indebtedness is added to our current indebtedness levels, the risks described above could substantially increase.

To service our indebtedness, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations.

Our ability to make payments on and to refinance our indebtedness, including our senior notes and loans under our credit agreements, and to fund planned capital expenditures will depend on our ability to generate cash from operations in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control, including the prices that we receive for oil and natural gas.

Our business may not generate sufficient cash flow from operations and future borrowings may not be available to us in an amount sufficient to enable us to pay our indebtedness, including our senior notes and loans under our credit agreements, or to fund our other liquidity needs. If our cash flow and capital resources are insufficient to fund our debt obligations, we may be forced to sell assets, seek additional equity or debt capital or restructure our debt. None of these remedies may, if necessary, be effected on commercially reasonable terms, or at all. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future, which could cause us to default on our obligations and could impair our liquidity.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our credit agreements contain a number of significant covenants that, among other things, restrict our ability to:

- dispose of assets;
- incur or guarantee additional indebtedness and issue certain types of preferred stock;
- pay dividends on our capital stock;
- create liens on our assets;
- enter into sale or leaseback transactions;
- enter into specified investments or acquisitions;
- repurchase, redeem or retire our capital stock or subordinated debt;
- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries;
- engage in specified transactions with subsidiaries and affiliates; or
- pursue other corporate activities.

Also, our credit agreements require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and, as a result, we may be unable to meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under our credit agreements and the Indenture governing our senior notes.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our credit arrangements. A default, if not cured or waived, could result in acceleration of all indebtedness outstanding under our credit arrangements. The accelerated debt would become immediately due and payable. If that should occur, we may be unable to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us.

Risks relating to our common stock

Our stock price may fluctuate significantly.

Our common stock began trading on the NYSE on February 9, 2006. An active trading market may not be sustained. The market price of our common stock could fluctuate significantly as a result of:

- actual or anticipated quarterly variations in our operating results;
- changes in expectations as to our future financial performance or changes in financial estimates of public market analysis;
- announcements relating to our business or the business of our competitors;
- conditions generally affecting the oil and natural gas industry;
- the success of our operating strategy; and
- the operating and stock price performance of other comparable companies.

Many of these factors are beyond our control and we cannot predict their potential effects on the price of our common stock. In addition, the stock markets in general can experience considerable price and volume fluctuations.

Future sales of our common stock may cause our stock price to decline.

As of December 31, 2007, we had 104,578,941 shares of common stock outstanding. All shares are freely tradable by persons other than our affiliates. Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock.

The equity trading markets may be volatile, which could result in losses for our shareholders.

The equity trading markets may experience periods of volatility, which could result in highly variable and unpredictable pricing of equity securities. The market price of our common stock could change in ways that may or may not be related to our business, our industry or our operating performance and financial condition.

Our articles of incorporation permit us to issue preferred stock that may restrict a takeover attempt that you may favor.

Our articles of incorporation permit our board to issue up to 10,000,000 shares of preferred stock and to establish, by resolution, one or more series of preferred stock and the powers, designations, preferences and participating, optional or other special rights of each series of preferred stock. The preferred stock may be issued on terms that are unfavorable to the holders of our common stock, including the grant of superior voting rights, the grant of preferences in favor of preferred shareholders in the payment of dividends and upon our liquidation and the designation of conversion rights that entitle holders of our preferred stock to convert their shares into our common stock on terms that are dilutive to holders of our common stock. The issuance of preferred stock in future offerings may make a takeover or change in control of us more difficult. In 2007, we issued 200,000 shares of preferred stock for proceeds of $2.0 billion to institutional accredited investors in a private placement under the Securities Act of 1933. See "Item 1. Business. Significant transactions during 2007—Private placement of preferred stock."

We have not paid dividends on our common stock in the past, and any return on investment has historically been limited to the value of our common stock.

We have never paid cash dividends on our common stock. The payment of dividends will depend on our earnings, capital requirements, financial condition, prospects and other factors our board of directors may deem relevant. If we do not pay dividends, our common stock may be less valuable because a return on your investment will only occur if our stock price appreciates. In addition, our credit agreements and the Indenture governing our senior notes restrict our ability to pay dividends.

Risks relating to our preferred stock

The holders of 7.0% Preferred Stock and Hybrid Preferred Stock have rights that could adversely affect an investment in our common stock.

On March 30, 2007, we completed the Private Placement of an aggregate of $390.0 million of 7.0% Preferred Stock and $1.61 billion of Hybrid Preferred Stock to accredited investors pursuant to the terms and conditions of a Preferred Stock Purchase Agreement dated March 28, 2007. The purchase price for each share was $10,000 (which equaled the liquidation preference per share on March 30, 2007). The designations, preferences, limitations and relative voting rights of the Hybrid Preferred Stock are identical to the designations, preferences, limitations and relative voting rights of the 7.0% Preferred Stock, including the right to dividends and the right to convert into shares of our common stock. The 7.0% Preferred Stock and the Hybrid Preferred Stock are convertible into shares of our common stock at an initial conversion price of $19.00 per share, subject to adjustment.

The initial $19.00 per share conversion price of the 7.0% Preferred Stock and the Hybrid Preferred Stock equates to each share of 7.0% Preferred Stock and Hybrid Preferred Stock being initially convertible into approximately 526.3 shares of our common stock, subject to adjustment for fractional shares. The Statement of Designation for each series of the 7.0% Preferred Stock and the Hybrid Preferred Stock contain weighted average anti-dilution provisions that provide for an adjustment to the conversion price of the 7.0% Preferred Stock and the Hybrid Preferred Stock upon (i) the issuance of stock, convertible securities or options at a price below the then-current conversion price, (ii) the issuance of options to holders of common stock at less than the current market price, (iii) a dividend or distribution to holders of common stock in excess of $0.06 per share in any quarter or (iv) an equity tender offer or share repurchase by us at a price in excess of the current market price. The exact number of shares of common stock into which the 7.0% Preferred Stock and the Hybrid Preferred Stock may ultimately be converted may vary over time as a result of the effects of these anti-dilutive adjustments to the conversion price. Assuming no adjustment to the $19.00 conversion price, the 7.0%

Preferred Stock and the Hybrid Preferred Stock are convertible into a total of 105,263,115 shares of our common stock.

The holders of 7.0% Preferred Stock and Hybrid Preferred Stock also have the right to receive cash dividends at the rate of 7.0% per annum prior to March 30, 2013 and at the rate of 9.0% per annum thereafter. In lieu of paying cash dividends, we may, under certain circumstances prior to March 30, 2013, pay such dividend at a rate of 9.0% per annum by adding the dividend to the liquidation preference of the shares of 7.0% Preferred Stock and Hybrid Preferred Stock. Upon the occurrence of a change of control, holders of 7.0% Preferred Stock and Hybrid Preferred Stock may require us to repurchase their shares for cash at the liquidation preference plus accumulated dividends. These anti-dilution, dividend and liquidation provisions could substantially dilute our common shareholders' interest and may otherwise adversely affect an investment in our common stock.

The holders of 7.0% Preferred Stock and Hybrid Preferred Stock could restrict our ability to enter into various corporate transactions that may be beneficial to our business strategy.

Without the prior consent of the holders of our 7.0% Preferred Stock and Hybrid Preferred Stock, we are generally prohibited from, among other things, the following:

- issuing shares of senior, parity or disqualified junior stock;
- amending our charter if the amendment would adversely affect any holder of 7.0% Preferred Stock or Hybrid Preferred Stock;
- increasing the size of our board of directors;
- entering into any merger or consolidation that is not permitted by our charter;
- effecting a change of control;
- distributing property or issuing dividends (other than as permitted by our charter) or engaging in an equity self-tender offer or share repurchase program; and
- effecting a sale or transfer of substantially all of our assets.

These restrictions may limit our ability to engage in activities which could expand our business, including obtaining future financing, making needed capital expenditures, or taking advantage of business opportunities such as strategic acquisitions and dispositions.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Corporate offices

We lease office space in Dallas, Texas, Akron, Ohio, Tulsa, Oklahoma, Shreveport, Louisiana and The Woodlands, Texas. We also have small offices for technical and field operations in Texas, Oklahoma, Louisiana, Colorado, Ohio and West Virginia. The table below summarizes our material corporate leases.

Location	Approximate square footage	Approximate monthly payment	Expiration
Dallas, Texas	75,000	$103,000	June 30, 2013
Akron, Ohio	30,700	48,100	December 15, 2012
Tulsa, Oklahoma	22,700	24,500	May 31, 2011
Shreveport, Louisiana	15,300	12,100	September 30, 2008
The Woodlands, Texas	13,800	28,700	June 30, 2012

Other

We have described our oil and natural gas properties, oil and natural gas reserves, acreage, wells, production and drilling activity in "Item 1. Business" of this Annual Report on Form 10-K.

ITEM 3. LEGAL PROCEEDINGS

On October 11, 2006, a putative class action was filed against our subsidiary, North Coast Energy, Inc. The case is styled *PRC Holdings, LLC, et al. v. North Coast Energy, Inc.* and was filed in the Circuit Court of Roane County, West Virginia. This action has been removed to the United States District Court for the Southern District of West Virginia. The action has been brought by certain landowners and lessors in West Virginia for themselves and on behalf of other similarly situated landowners and lessors in West Virginia. The lawsuit alleges that North Coast Energy, Inc. has not been paying royalties to the plaintiffs in the manner required under the applicable leases, has provided misleading documentation to the plaintiffs regarding the royalties due, and has breached various other contractual, statutory and fiduciary duties to the plaintiffs with regard to the payment of royalties. In a case styled *The Estate of Garrison Tawney v. Columbia Natural Resources, LLC* announced in June 2006, the West Virginia Supreme Court held that language such as "at the wellhead" and similar language contained in leases when used in describing how to calculate royalties due lessors was ambiguous and, therefore, should be construed strictly against the lessee. Accordingly, in the absence of express language in a lease that is intended to allocate between a lessor and lessee post-production costs such as the costs of marketing the product and transporting it to the point of sale, no post-production costs may be deducted from the lessor's royalty payment due from the lessee. The claims alleged by the plaintiffs in the lawsuit filed against us are similar to the claims alleged in the *Tawney* case. Plaintiffs are seeking common law and statutory compensatory and punitive damages, interest and costs and other remedies. The Company is vigorously defending the existing lawsuit. The action is in a very preliminary stage. The preliminary status of the lawsuit leaves the ultimate outcome of this litigation uncertain. The Company believes that it has substantial defenses to this lawsuit and that the adverse affects from this litigation, if any, are reflected in our financial statements and we do not expect the ultimate outcome of the lawsuit to have a material effect on our financial position, results of operations or cash flows.

In the ordinary course of business, we are periodically a party to lawsuits and claims. We do not believe that any resulting liability from existing legal proceedings, individually or in the aggregate, will have a material adverse effect on our results of operations or financial condition.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

For a description of matters related to the resignation of Vincent J. Cebula as the Series B Preferred Stock Director and his simultaneous election as a general Preferred Stock Director by the holders of our Preferred Stock and the election of B. James Ford to our board of directors as the

Series B Preferred Stock Director by the holders of our Preferred Stock, please see our Current Report on Form 8-K dated December 1, 2007 and filed with the SEC on December 5, 2007 and incorporated herein by reference.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market information for our common stock

Prior to February 14, 2006, we were 100% owned by EXCO Holdings. Effective February 9, 2006, our common stock began trading on a "when issued" basis on the NYSE under the symbol "XCO".

The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock as reported by the NYSE:

	Common Stock	
	High	Low
Year ended December 31, 2007:		
First Quarter	$18.35	$15.07
Second Quarter	19.70	15.89
Third Quarter	18.27	14.69
Fourth Quarter	17.48	13.61
Year ended December 31, 2006:		
First Quarter	$13.70	$11.81
Second Quarter	13.03	9.55
Third Quarter	15.00	10.05
Fourth Quarter	18.20	12.15

Our shareholders

According to our transfer agent, Continental Stock Transfer & Trust Company, there were approximately 146 holders of record of our common stock on December 31, 2007 (including nominee holders such as banks and brokerage firms who hold shares for beneficial holders).

Our dividend policy

We have not paid any cash dividends on our common stock. In addition, our credit agreements currently prohibit us from paying dividends on our common stock and the Indenture governing our senior notes contains restrictions on our payment of dividends. Even if our credit agreement permitted us to pay cash dividends, we can make those payments only from our surplus (the excess of the fair value of our total assets over the sum of our liabilities plus our total paid-in share capital). In addition, we can pay cash dividends only if after paying those dividends we would be able to pay our liabilities as they become due.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents our selected historical financial and operating data. You should read this financial data in conjunction with "Item 7. Management's discussion and analysis of financial condition and results of operations," our consolidated financial statements, the notes to our consolidated financial statements and the other financial information, included in this Annual Report on Form 10-K. This information does not replace the consolidated financial statements. We have completed numerous acquisitions and dispositions since 2003 that materially impact the comparability of this data between periods.

The selected financial data for the 209 day period from January 1, 2003 to July 28, 2003 is referred to as public predecessor and represents accounting periods when EXCO was a publicly traded company on the Nasdaq. On July 29, 2003, EXCO completed a going private transaction which resulted in a change of accounting basis. The selected financial data for the 156 day period from July 29, 2003 to December 31, 2003, the twelve months ended December 31, 2004 and the 275 day period from January 1, 2005 to October 2, 2005 is referred to as predecessor and represents the period of time when EXCO was privately held. The period from the Equity Buyout on October 3, 2005, which resulted in an additional change in accounting basis, through December 31, 2007 is referred to as successor.

Selected consolidated financial and operating data

(in thousands, except per share amounts)	Public Predecessor	Predecessor			Successor		
	209 day period from January 1 to July 28, 2003	156 day period from July 29 to December 31, 2003	2004	275 day period from January 1 to October 2, 2005	90 day period from October 3 to December 31, 2005	2006	2007
Statement of operations data(1):							
Revenues and other income:							
Oil and natural gas	$22,403	$ 21,767	$141,993	$ 132,821	$70,061	$355,780	$ 846,060
Derivative financial instruments(2)	—	(10,800)	(50,343)	(177,253)	(256)	198,664	26,807
Other income	(1,129)	(141)	1,184	7,096	2,374	5,005	33,643
Total revenues and other income	21,274	10,826	92,834	(37,336)	72,179	559,449	906,510
Costs and expenses:							
Oil and natural gas production	11,380	7,331	28,256	22,157	8,949	68,874	170,440
Depreciation, depletion and amortization	5,125	5,413	28,519	24,687	14,071	135,722	375,420
Accretion of discount on asset retirement obligations(3)	320	205	800	617	226	2,014	4,878
General and administrative(4)	11,347	3,874	15,466	89,442	6,375	41,206	64,670
Interest expense	1,058	1,921	34,570	26,675	19,414	84,871	181,350
Total costs and expenses	29,230	18,744	107,611	163,578	49,035	332,687	796,758
Equity in income of TXOK Acquisition, Inc.	—	—	—	—	837	1,593	—
Income (loss) before income taxes	(7,956)	(7,918)	(14,777)	(200,914)	23,981	228,355	109,752
Income tax expense (benefit)	(181)	(7,764)	5,126	(63,698)	7,631	89,401	60,096
Income (loss) before discontinued operations and change in accounting principle	(7,775)	(154)	(19,903)	(137,216)	16,350	138,954	49,656
Discontinued operations:							
Income (loss) from discontinued operations	13,534	6,217	36,274	(4,403)	—	—	—
Gain on disposition of Addison Energy Inc.	—	—	—	175,717	—	—	—
Income tax expense	4,982	1,917	10,358	49,282	—	—	—
Income from discontinued operations	8,552	4,300	25,916	122,032	—	—	—
Income (loss) before change in accounting principle	777	4,146	6,013	(15,184)	16,350	138,954	49,656
Cumulative effect of change in accounting principle, net of income tax	255	—	—	—	—	—	—
Net income (loss)	1,032	4,146	6,013	(15,184)	16,350	138,954	49,656
Dividends on preferred stock	(2,620)	—	—	—	—	—	(132,968)
Net income (loss) available to common shareholders	$(1,588)	$ 4,146	$ 6,013	$ (15,184)	$16,350	$138,954	$ (83,312)
Basic income (loss) per share from continuing operations	$ (1.25)	$ —	$ (0.17)	$ (1.18)	$ 0.35	$ 1.44	$ (0.80)
Basic income (loss) per share—total	$ (0.19)	$ 0.04	$ 0.05	$ (0.13)	$ 0.35	$ 1.44	$ (0.80)
Diluted income (loss) per share from continuing operations	$ (1.25)	$ —	$ (0.17)	$ (1.18)	$ 0.35	$ 1.41	$ (0.80)
Diluted income (loss) per share—total	$ (0.19)	$ 0.04	$ 0.05	$ (0.13)	$ 0.35	$ 1.41	$ (0.80)
Weighted average common and common equivalent shares outstanding:							
Basic	8,084	115,947	115,947	116,504	47,222	96,727	104,364
Diluted	8,084	115,947	115,947	116,504	47,222	98,453	104,364

Selected consolidated financial and operating data (continued)

(in thousands, except per share amounts)	Public Predecessor	Predecessor			Successor		
	209 day period from January 1 to July 28, 2003	156 day period from July 29 to December 31, 2003	2004	275 day period from January 1 to October 2, 2005	90 day period from October 3 to December 31, 2005	2006	2007
Statement of cash flow data:(2)							
Net cash provided by (used in):							
Operating activities	$ 20,418	$ 21,495	$ 118,528	$ (81,122)	$ 8,177	$ 227,659	$ 577,829
Investing activities	(23,520)	(237,623)	(381,476)	337,880	(13,337)	(1,791,517)	(2,396,437)
Financing activities	9,982	214,284	283,708	(47,035)	(4,018)	1,359,727	1,851,296
Balance sheet data:(2)							
Current assets	n/a	$ 31,641	$ 75,877	n/a	$ 342,525	$ 236,710	$ 311,300
Total assets	n/a	505,056	922,052	n/a	1,530,493	3,707,057	5,955,771
Current liabilities	n/a	45,188	105,695	n/a	465,725	190,924	278,167
Long-term debt, less current maturities	n/a	—	487,453	n/a	461,802	2,081,653	2,099,171
Shareholders' equity	n/a	183,895	203,885	n/a	370,882	1,179,850	1,115,742
Total liabilities and shareholders' equity	n/a	505,056	922,052	n/a	1,530,493	3,707,057	5,955,771

(1) We have completed numerous acquisitions and dispositions since January 1, 2003 that materially impact the comparability the selected financial data between periods.

(2) On July 28, 2003, EXCO completed a going private transaction which resulted in a change of control and a new basis of accounting. Upon consummation of the going private transaction, we discontinued the designation of our derivative financial instruments as hedges. Beginning with July 29, 2003, changes in the fair value of our derivative financial instruments are recognized directly in our statement of operations. See "Item 7. Managements discussion and analysis of financial condition and results of operations—Critical accounting policies—Accounting for derivatives" for a description of this accounting method.

(3) We adopted SFAS No. 143, "Accounting for asset retirement obligations," or SFAS No. 143, on January 1, 2003. See "Note 2. Summary of significant accounting policies—Deferred abandonment and asset retirement obligations" in the notes to our consolidated financial statements included in this Annual Report on Form 10-K.

(4) The 275 day period from January 1, 2005 to October 2, 2005 includes non-cash based compensation of $44.1 million and Equity Buyout compensation expenses of $29.6 million. We adopted SFAS No. 123(R), "Share-Based Payment", or SFAS No. 123(R), on October 3, 2005. Share-based compensation, pursuant to SFAS No. 123(R), included in general and administrative expenses is $3.0 million, $6.5 million and $9.0 million for the 90 day period from October 3, 2005 to December 31, 2005 and the twelve months ended December 31, 2006 and 2007, respectively. See "Note 2. Summary of significant accounting policies—Stock options" in the notes to our consolidated financial statements included in this Annual Report on Form 10-K.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our financial statements and the related notes to those statements included elsewhere in this Annual Report on Form10-K. In addition to historical financial information, the following discussion and analysis contains forward-looking statements that involve risks, uncertainties and assumptions. Our results and the timing of selected events may differ materially from those anticipated in these forward-looking statements as a result of many factors including those discussed under "risk factors" and elsewhere in this Annual Report on Form 10-K.

Overview and history

We are an independent oil and natural gas company engaged in the acquisition, development and exploitation of onshore North American oil and natural gas properties and, until February 10, 2005, in Canada. We expect to continue to grow by leveraging our management team's experience, exploiting our multi-year inventory of development drilling locations and exploitation projects, and selectively pursuing acquisitions that meet our strategic and financial objectives. We employ the use of debt along with a comprehensive derivative financial instrument program to support our acquisition strategy. This approach enhances our ability to execute our business plan over the entire commodity price cycle, protect our returns on investments, and manage our capital structure. In 2006 and 2007, we closed acquisitions of producing properties, undeveloped acreage, undeveloped properties and oil and natural gas gathering and transportation facilities totaling $2.1 billion and $2.5 billion, respectively. In 2007, we drilled 506 wells and completed 495 gross (397.2 net) wells with a 98% drilling success rate. Our 2007 development, exploitation and other oil and natural gas property capital spending activities totaled $487.2 million. In addition, our midstream and corporate capital expenditures totaled $48.3 million. Our acquisitions in 2007 were funded, in part, by a $2.0 billion private placement of preferred stock. We also amended our credit agreements in 2007 to reflect the increased borrowing capacity resulting from our acquisitions. Our 2008 capital budget, approved by our Board of Directors, totals $625.2 million. We expect to drill and complete over 600 gross (approximately 526 net) wells in 2008, along with other activities.

Oil and natural gas prices have historically been volatile. During 2007, the NYMEX price for natural gas has fluctuated from a high of $8.64 per Mmbtu to a low of $5.38 per Mmbtu. On December 31, 2007, the spot market price for natural gas at Henry Hub was $6.80 per Mmbtu, a 21% increase from December 31, 2006. The price of oil has shown similar volatility. In 2007, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were $71.17 per Bbl and $6.54 per Mcf compared with 2006 prices of $62.27 per Bbl and $6.77 per Mcf, respectively. The volatile commodity price environment from 2005 through 2007, which was accentuated in 2005 by historical high prices for natural gas after the hurricanes in the third quarter of 2005, caused an increase in demand for drilling rigs, field supplies and related oil field service costs. EXCO, as well as other producers of oil and natural gas, experienced some difficulty in timely scheduling drilling and related services during this period. However, we have not encountered any significant operational problems or operational delays as a result of these scheduling difficulties. We cannot predict the impact that the continuing volatility in oil and natural gas prices could cause to our operating revenues, results of operations, or capital budgets nor can we predict the impact on the pricing for drilling rigs and related oil field services. Management continuously monitors its operations and capital budget and employs the use of derivative financial instruments to lessen the impact of fluctuating prices for oil and natural gas.

Like all oil and natural gas production companies, we face the challenge of natural production declines. Oil and natural gas production from a given well naturally decreases over time. We attempt to overcome this natural decline by drilling to identify and develop additional reserves and by acquisitions.

Our future growth will depend upon our ability to continue to identify and add oil and natural gas reserves in excess of production at a reasonable cost. We will maintain our focus on the costs of adding reserves through drilling and acquisitions as well as the costs necessary to produce such reserves.

We also face the challenge of financing future acquisitions. Following completion of our initial public offering, or IPO, in February 2006, we amended our revolving credit agreement with our banking syndicate. As a result of our 2006 and 2007 acquisitions our credit agreements have been further amended. We also completed a $2.0 billion private placement of preferred stock in March 2007 and used the proceeds to fund acquisitions and reduce debt in our credit agreements. On February 20, 2008, the EXCO Resources Credit Agreement had a borrowing base of $1.2 billion, $920.5 million of which was drawn, and the EPOP Credit Agreement had a borrowing base of $1.3 billion, $1.1 billion of which was drawn. We believe we will have adequate unused borrowing capacity under our credit agreements and available cash flow from operations to fund capital development and working capital needs for the next 12 months. Funding for future acquisitions may require additional sources of financing, which may not be available.

Critical accounting policies

In response to the SEC's Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," we have identified the most critical accounting policies used in the preparation of our consolidated financial statements. We determined the critical policies by considering accounting policies that involve the most complex or subjective decisions or assessments. We identified our most critical accounting policies to be those related to our Proved Reserves, accounting for business combinations, accounting for derivatives, share-based payments, our choice of accounting method for oil and natural gas properties, goodwill, asset retirement obligations and income taxes.

We prepared our consolidated financial statements for inclusion in this report in accordance with GAAP. GAAP represents a comprehensive set of accounting and disclosure rules and requirements, and applying these rules and requirements requires management judgments and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. The following is a discussion of our most critical accounting policies, judgments and uncertainties that are inherent in our application of GAAP.

Estimates of Proved Reserves

The Proved Reserves data included in this Annual Report on Form 10-K was prepared in accordance with SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

You should not assume that the present value of future net cash flows represents the current market value of our estimated Proved Reserves. In accordance with SEC requirements, we based the estimated discounted future net cash flows from Proved Reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Further, the mandated discount rate of 10% may not be an accurate assumption of future interest rates.

Proved Reserves quantities directly and materially impact depletion expense. If the Proved Reserves decline, then the rate at which we record depletion expense increases, reducing net income. A decline in the estimate of Proved Reserves may result from lower market prices, and a decline may make it uneconomical to drill or produce from higher cost fields. In addition, a decline in Proved Reserves may impact the outcome of our assessment of our oil and natural gas properties and require an impairment of the carrying value of our oil and natural gas properties.

Proved Reserves are defined as the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., 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 based upon future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (i) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (ii) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of Proved Reserves do not include the following: (i) oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (ii) crude oil and natural gas, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (iii) crude oil and natural gas, that may occur in undrilled prospects; and (iv) crude oil and natural gas that may be recovered from oil shales, coal, gilsonite and other such sources.

Business combinations

We follow SFAS No. 141 "Accounting for Business Combinations", or SFAS No. 141, to record our acquisitions of oil and natural gas properties or entities which we acquire. SFAS No. 141 requires that acquired assets, identifiable intangible assets and liabilities be recorded at their fair value, with any excess purchase price being recognized as goodwill. Application of SFAS No. 141 requires significant estimates to be made by management using information available at the time of acquisition. Since these estimates require the use of significant judgment, actual results could vary as the estimates are subject to changes as new information becomes available.

Accounting for derivatives

We use derivative financial instruments to protect against commodity price fluctuations and in connection with the incurrence of debt related to our acquisition activities. Our objective in entering into these derivative financial instruments is to manage price fluctuations and achieve a more predictable cash flow to fund our development, acquisition activities and support debt incurred with our acquisitions. These derivative financial instruments are not held for trading purposes. We do not designate our derivative financial instruments as hedging instruments and, as a result, we recognize the change in the derivative's fair value as a component of current earnings.

Share-based payments

We account for share-based payments to employees using the methodology prescribed in SFAS No. 123(R) and related interpretations. At December 31, 2007, our employees and directors held options under EXCO's 2005 Long-Term Incentive Plan, or the 2005 Incentive Plan, to purchase 12,402,773 shares of EXCO common stock at prices ranging from $7.50 per share to $18.44 per share. The options expire ten years from the date of grant. Pursuant to the 2005 Incentive Plan, 25% of the options vest immediately with an additional 25% to vest on each of the next three anniversaries of the date of grant. We use the Black-Scholes model to calculate the fair value of issued options. The gross fair value of the granted options using the Black-Scholes model range from $2.29 per share to $6.53 per share. SFAS No. 123(R) requires share-based compensation be recorded with cost classifications consistent with cash compensation. EXCO uses the full cost method to account for its oil and natural gas properties. As a result, part of our share-based payments are capitalized. Total share-based compensation for 2007 was $15.0 million, of which $2.4 million was capitalized as part of our oil and natural gas properties. In 2006, a total of $7.9 million of share-based compensation was incurred, of which $1.4 million was capitalized.

Accounting for oil and natural gas properties

The accounting for, and disclosure of, oil and natural gas producing activities requires that we choose between two GAAP alternatives; the full cost method or the successful efforts method.

We use the full cost method of accounting, which involves capitalizing all costs associated with the acquisition, exploration, exploitation and development of oil and natural gas properties. Once we incur costs, they are recorded in the depletable pool of proved properties or in unproved properties, collectively, the full cost pool. Unproved property costs are not subject to depletion. We review our unproved oil and natural gas property costs on an ongoing basis, and we expect these costs to be evaluated in one to seven years and transferred to the depletable portion of the full cost pool during that time. The full cost pool is comprised of intangible drilling costs, lease and well equipment and exploration and development costs incurred plus costs of acquired proved and unproved leaseholds.

We calculate depletion using the unit-of-production method. Under this method, the sum of the full cost pool and all estimated future development costs are divided by the total amount of Proved Reserves. This rate is applied to our total production for the period, and the appropriate expense is recorded. We capitalize the portion of general and administrative costs, including share-based compensation, that is attributable to our acquisition, exploration, exploitation and development activities.

At the end of each quarterly period, the unamortized cost of proved oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using current period-end prices discounted at 10%, adjusted for related income tax effects (ceiling test). Until February 10, 2005, this ceiling test calculation was done separately for the United States and for our Canadian subsidiary full cost pools. When computing our ceiling test, we evaluate the limitation at the end of each reporting period date. In the event our capitalized costs exceed the ceiling limitation at the end of the reporting date, we subsequently evaluate the limitation for price changes that occur after the balance sheet to assess impairment as permitted by Staff Accounting Bulletin Topic 12—Oil and Gas Producing Activities. In addition, in July 2007 we sought and received an exemption from the SEC to exclude the proved oil and natural gas properties of the Winchester acquisition, and those acquired in the Vernon Acquisition and the Southern Gas Acquisition from our ceiling test for a period of 12 months from the closing date of each acquisition, provided that we could demonstrate beyond a reasonable doubt that the fair value of the oil and natural gas reserves exceeded their unamortized carrying costs. The exemption related to Winchester expired September 30, 2007 and therefore the proved oil and natural gas properties of Winchester were included in our December 31, 2007 ceiling test calculation. The exemption for the Vernon Acquisition will expire on March 30, 2008 and the exemption for the Southern Gas Acquisition will expire on May 2, 2008.

The quarterly calculation of the ceiling test is based upon estimates of Proved Reserves. There are numerous uncertainties inherent in estimating quantities of Proved Reserves, in projecting the future rates of production and in the timing of development activities. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Goodwill

As a result of the Equity Buyout on October 3, 2005, which required the application of the purchase method of accounting pursuant to SFAS No. 141, goodwill of $220.0 million was recognized. Additional goodwill of $250.1 million was recognized from our 2006 acquisitions. As of December 31, 2007, our consolidated goodwill totals $470.1 million. Our strategy is to concentrate on accumulating assets in East Texas, North Louisiana, the Mid-Continent region and Appalachia. We believe the strategic value paid for the assets substantiates the goodwill we have incurred.

None of the goodwill is currently deductible for income tax purposes. Furthermore, in accordance with SFAS No. 142, "Goodwill and Intangible Assets," or SFAS No. 142, goodwill is not amortized, but is tested for impairment on an annual basis, or more frequently as impairment indicators arise. Impairment tests, which involve the use of estimates related to the fair market value of the business operations with which goodwill is associated, are subject to various assumptions and judgments. Actual future results of these assumptions could differ as a result of economic changes which are not within our control. Losses, if any, resulting from impairment tests will be reflected in operating income in the statement of operations.

Asset retirement obligations

We follow SFAS No. 143 to account for legal obligations associated with the retirement of long-lived assets. SFAS No. 143 requires these obligations be recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The costs of plugging and abandoning oil and natural gas properties fluctuate with costs associated with the industry. We periodically assess the estimated costs of our asset retirement obligations and adjust the liability according to these estimates.

Accounting for income taxes

Income taxes are accounted for using the liability method of accounting in accordance with SFAS No. 109, "Accounting for Income Taxes," or SFAS No. 109. We must make certain estimates related to the reversal of temporary differences, and actual results could vary from those estimates. Deferred taxes are recorded to reflect the tax benefits and consequences of future years' differences between the tax basis of assets and liabilities and their financial reporting basis. We record a valuation allowance to reduce deferred tax assets if it is more likely than not that some portion or all of the deferred tax assets will not be realized.

In July 2006, the Financial Accounting Standards Board, or FASB, issued Financial Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," or FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with Statement of Financial Accounting Standards, or SFAS, No. 109, "Accounting for Income Taxes." FIN 48 provides guidance on recognizing, measuring, presenting and disclosing in the financial statements uncertainties relating to tax positions that a company has taken or expects to take on a tax return. We adopted FIN 48 on January 1, 2007. The adoption of FIN 48 did not have a material impact on our consolidated financial position or results of operations.

Recent accounting pronouncements

The FASB issued FASB Staff Position EITF 00-19-2 "Accounting for Registration Payment Arrangements," or FSP 00-19-2, on December 21, 2006. FSP 00-19-2 requires contingent obligations to make future payments under a registration payment arrangement to be recognized separately in accordance with SFAS No. 5, "Accounting for Contingencies," or SFAS No. 5. SFAS No. 5 requires that an estimated loss from a loss contingency be accrued if the loss is probable and can reasonably be estimated. Our 7.0% Preferred Stock and Hybrid Preferred Stock contain requirements for EXCO, in certain circumstances, to register shares on behalf of the preferred stockholders. On September 5, 2007, we filed an automatically effective registration statement on Form S-3 with the SEC to register for resale the shares of common stock issuable upon conversion of the Series A-1 7.0% Preferred Stock and the Series A-1 Hybrid Preferred Stock. If such registration deadlines are not met, or a prior registration statement ceases to remain effective, we may be obligated to pay liquidated damages. We adopted FSP 00-19-2 upon issuance of the 7.0% Preferred Stock and the Hybrid Preferred Stock. We do not believe any of the contingencies associated with the registration rights of the preferred stockholders are probable as of December 31, 2007 and therefore they are not valued separately at December 31, 2007.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," or SFAS No. 157, which defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years for financial assets and liabilities. In February 2008, the FASB issued a one year deferral for non-financial assets and liabilities. We adopted SFAS No. 157 for financial instruments on January 1, 2008. We will adopt SFAS No. 157 for non-financial assets and liabilities on January 1, 2009. The adoption of SFAS No. 157 is not expected to have a significant effect on our financial statements.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB Statement No. 115," or SFAS No. 159. SFAS No. 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. The fair value option established by SFAS No. 159 permits us to choose to measure eligible items at fair value at specified election dates. Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and as such, was adopted by us on January 1, 2008. The adoption of SFAS No. 159 is not expected to have a significant effect on our financial statements.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations," or SFAS No. 141(R). SFAS No. 141(R) replaces SFAS No. 141. SFAS No. 141(R) broadens the scope of business combinations to include bargain purchases and combinations of related companies, provides guidance on measuring goodwill and requires acquisition costs to be separate from the value of assets and liabilities purchased. SFAS No. 141(R) is effective for financial statements issued for fiscal years beginning after December 15, 2008, and as such, will be adopted by us on January 1, 2009. We are currently evaluating the effect of adopting SFAS No. 141(R) on our financial statements.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements," or SFAS No. 160. SFAS No. 160 amends Accounting Research Bulletin 51, or ARB 51. SFAS No. 160 requires the recognition of a noncontrolling interest (minority interest) as equity in the consolidated financial statements separate from the parent's equity. The amount of net income attributable to the noncontrolling interest will be included in consolidated net income on the face of the income statement. It also amends certain of ARB No. 51's consolidation procedures for consistency with the requirements of SFAS No. 141(R). SFAS No. 160 also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. SFAS No. 160 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and as such, will be adopted by us on January 1, 2009. We are currently evaluating the effect of adopting SFAS No. 160 on our financial statements.

Our results of operations

Due to the application of purchase accounting for the Equity Buyout in October 2005, our results of operations contain predecessor and successor periods. Because the application of purchase accounting can inhibit meaningful comparison of historical results before and after such transactions, we analyzed the impact of the Equity Buyout on our statements of operations. We believe that our results of operations for 2005, 2006 and 2007 are comparable on an annual basis except as it relates to depreciation, depletion and amortization expenses resulting from a change in basis of the underlying properties in 2005. As a result we believe that the non-GAAP measure for 2005, discussed below, provides a more meaningful basis for comparing our results of operations. A summary of key financial data for 2005, 2006 and 2007 related to our results of operations for the years then ended is presented below.

(dollars in thousands, except per unit price)	Predecessor For the 275 day period from January 1, 2005 to October 2, 2005	Successor For the 90 day period from October 3, 2005 to December 31, 2005	Non-GAAP combined 2005	Successor Year ended December 31, 2006	Successor Year ended December 31, 2007	Year to year change 2005-2006(b)	Year to year change 2006-2007
Production:							
Oil (Mbbls)	375	116	491	916	1,645	425	729
Natural gas (Mmcf)(a)	15,490	5,112	20,602	44,123	111,419	23,521	67,296
Total production (Mmcfe)	17,740	5,808	23,548	49,619	121,289	26,071	71,670
Oil and natural gas revenues before derivative financial instrument activities:							
Oil revenues	$ 19,528	$ 6,666	$ 26,194	$ 57,043	$ 117,073	$ 30,849	$ 60,030
Natural gas sales(a)	113,293	63,395	176,688	298,737	728,987	122,049	430,250
Total oil and gas sales	$ 132,821	$ 70,061	$ 202,882	$355,780	$ 846,060	$152,898	$ 490,280
Derivative financial instruments:							
Cash settlements on derivative financial instruments	$ (62,842)	$(22,210)	$ (85,052)	$ 29,423	$ 108,413	$114,475	$ 78,990
Non-cash change in fair value of derivative financial instruments	(114,411)	21,954	(92,457)	169,241	(81,606)	261,698	(250,847)
Total derivative financial instrument activities	$(177,253)	$ (256)	$(177,509)	$198,664	$ 26,807	$376,173	$(171,857)
Average sales price (before cash settlements of derivative financial instruments):							
Oil (Bbl)	$ 52.07	$ 57.47	$ 53.35	$ 62.27	$ 71.17	$ 8.92	$ 8.90
Natural gas (per Mcf)	7.31	12.40	8.58	6.77	6.54	(1.81)	(0.23)
Natural gas equivalent (per Mcfe)	7.49	12.06	8.62	7.17	6.98	(1.45)	(0.19)
Oil and natural gas production costs:							
Oil and natural gas operating costs	$ 14,581	$ 5,485	$ 20,066	$ 46,534	$ 117,160	$ 26,468	$ 70,626
Production and ad valorem taxes	7,576	3,464	11,040	22,340	53,280	11,300	30,940
Depreciation, depletion and amortization	24,687	14,071	38,758	135,722	375,420	96,964	239,698
General and administrative(c)	89,442	6,375	95,817	41,206	64,670	(54,611)	23,464
Interest expense	26,675	19,414	46,089	84,871	181,350	38,782	96,479
Expenses (per Mcfe):							
Oil and natural gas operating costs	$ 0.82	$ 0.94	$ 0.85	$ 0.94	$ 0.97	$ 0.09	$ 0.03
Production and ad valorem taxes	0.43	0.60	0.47	0.45	0.44	(0.02)	(0.01)
Depreciation, depletion and amortization	1.39	2.42	1.65	2.74	3.10	1.09	0.36
General and administrative	5.04	1.10	4.07	0.83	0.53	(3.24)	(0.30)
Net income (loss)(d)	$(137,216)	$ 16,350	$(120,866)	$138,954	$ 49,656	$259,820	$ (89,298)
Preferred stock dividends	—	—	—	—	(132,968)	—	(132,968)
Income (loss) available to common shareholders	$(137,216)	$ 16,350	$(120,866)	$138,954	$ (83,312)	$259,820	$(222,266)

(a) Natural gas production and sales include volumes and values previously reported as natural gas liquids for the 275 day period from January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005 and the non-GAAP combined 2005. Barrels of natural gas liquids volumes have been calculated by converting one barrel of natural gas liquids to six Mcf of natural gas.

(b) Year to year changes relative to 2005 are calculated using non-GAAP combined 2005 totals.

(c) The 275 day period from January 1, 2005 to October 2, 2005 includes non-cash based compensation of $44.1 million and Equity Buyout compensation expenses of $29.6 million. We adopted SFAS No. 123(R), "Share-Based Payment", or SFAS No. 123(R), on October 3, 2005. Share-based compensation, pursuant to SFAS No. 123(R), included in general and administrative expenses is $3.0 million, $6.5 million and $9.0 million for the 90 day period from October 3, 2005 to December 31, 2005 and the twelve months ended December 31, 2006 and 2007, respectively. See "Note 2. Summary of significant accounting policies—Stock options" in the notes to our consolidated financial statements included in this Annual Report on Form 10-K.

(d) The Predecessor net loss represents net loss from continuing operations. A $122.0 million after-tax gain from the sale of our Canadian subsidiary in February 2005 was reported as a discontinued operation and is not presented on this table.

The following is a discussion of our financial condition and results of operations for the years ended December 31, 2005, 2006 and 2007. Information presented for the year ended December 31, 2005 represents the non-GAAP combined total for the 275 day period from January 1, 2005 to October 2, 2005 (predecessor) and the 90 day period from October 3, 2005 to December 31, 2005 (successor).

The comparability of our results of operations from 2005, 2006 and 2007 is impacted by:

- property acquisitions and dispositions, including the sale of our Canadian subsidiary on February 10, 2005;
- significant fluctuations in oil and natural gas prices which impact our oil and natural gas revenues;
- changes in our Proved Reserves and their impact on depreciation, depletion and amortization;
- fluctuations associated with use of mark-to-market for derivative financial instruments;
- the Equity Buyout that occurred on October 3, 2005, the significant amount of debt incurred to finance the Equity Buyout and the resulting step-up in accounting basis;
- compensation expenses related to the Equity Buyout and the adoption of SFAS No. 123(R);
- the IPO that closed on February 14, 2006;
- the acquisition of TXOK on February 14, 2006, PGMT on April 28, 2006 and Winchester on October 2, 2006;
- the incurrence of debt to finance the Winchester acquisition, the Vernon Acquisition and the Southern Gas Acquisition;
- the $2.0 billion private placement of preferred stock on March 30, 2007; and
- other property sales.

The availability of a ready market for oil and natural gas and the prices of oil and natural gas are dependent upon a number of factors that are beyond our control. These factors include, among other things:

- the level of domestic production and economic activity generally;
- the availability of imported oil and natural gas;
- actions taken by foreign oil producing nations;
- the cost and availability of natural gas pipelines with adequate capacity and other transportation facilities;
- the cost and availability of other competitive fuels, fluctuating and seasonal demand for oil, natural gas and refined products; and
- the extent of governmental regulation and taxation (under both present and future legislation) of the production, refining, transportation, pricing, use and allocation of oil, natural gas, refined products and substitute fuels.

Accordingly, in light of the many uncertainties affecting the supply and demand for oil, natural gas and refined petroleum products, we cannot accurately predict the prices or marketability of the oil and natural gas from any producing well in which we have or may acquire an interest.

Marketing arrangements and backlog

We produce oil and natural gas. We do not refine or process the oil we produce. We sell the majority of the oil we produce under short-term contracts using market sensitive pricing. The majority of our oil contracts are based on NYMEX pricing, which is typically calculated as the average of the daily closing prices of oil to be delivered one month in the future. We also sell a portion of our oil at F.O.B. field prices posted by the principal purchaser of oil where our producing properties are located. Our sales contracts are of a type common within the industry, and we usually negotiate a separate contract for each property. Generally, we sell our oil to purchasers and refiners near the areas of our producing properties.

We sell the majority of our natural gas under individually negotiated gas purchase contracts using market sensitive pricing. Our natural gas contracts vary in length from spot market sales of a single day to term agreements that may extend for a year or more. Our natural gas customers include utilities, natural gas marketing companies and a variety of commercial and industrial end users. The natural gas purchase contracts define the terms and conditions unique to each of these sales. The prices received for natural gas sold on the spot market varies daily, reflecting changing market conditions. We also gather and transport natural gas for other producers in fields which we operate for which we are compensated.

For the twelve months ended December 31, 2007, sales to a regulated natural gas utility company, Atmos Energy Marketing L.L.C. and its affiliates, and an independent oil and natural gas company, Anadarko and its affiliates, accounted for 20.0% and 12.1%, respectively, of total oil and natural gas revenues. For the twelve months ended December 31, 2006 and 2005 sales to one industrial customer, Alcan Rolled Products—Ravenswood, LLC, accounted for 4.9% and 10.1%, respectively, of total oil and natural gas revenues. The loss of any significant customer may cause a temporary interruption in sales of, or a lower price for, our oil and natural gas, but we believe that the loss of any one customer would not have a material adverse effect on our results of operations or financial condition.

We may be unable to market all the oil and natural gas we produce. If our oil and natural gas can be marketed, we may be unable to negotiate favorable price and contractual terms. Changes in oil or natural gas prices may significantly affect our revenues, cash flows, the value of our oil and natural gas properties and the estimates of economically recoverable oil and natural gas contained in our properties. Further, significant declines in the prices of oil or natural gas may have a material adverse effect on our business and on our financial condition.

We engage in oil and natural gas production activities in geographic regions where, from time to time, the supply of oil or natural gas available for delivery exceeds the demand. In this situation, companies purchasing oil or natural gas in these areas reduce the amount of oil or natural gas that they purchase from us. If we cannot locate other buyers for our production or for any of our newly discovered oil or natural gas reserves, we may shut-in our oil or natural gas wells for periods of time. If this occurs, we may incur additional payment obligations under our oil and natural gas leases and, under certain circumstances, the oil and natural gas leases might be terminated.

Summary

For purposes of comparative analysis, we have combined the predecessor and successor operating results for the 2005 periods and refer to the combined results as non-GAAP 2005.

For the year ended December 31, 2007, we had a net loss available to common shareholders of $83.3 million compared to net income of $139.0 million for 2006. For the 2005 non-GAAP combined period we incurred a net loss from continuing operations of $120.9 million and net income of $1.2 million, reflecting a gain on the sale of our Canadian subsidiary of $122.0 million.

The impact of acquisitions and derivative financial instruments are significant to our results of operations. During 2007, we closed approximately $2.5 billion of acquisitions of oil and natural gas properties which significantly increased our production, revenues and operating costs. In addition, we do not designate our derivative financial instruments as hedges. Therefore, we mark the changes in the fair value of our unsettled derivative financial instruments to market at the end of each reporting period. Due to significant fluctuations in the price of oil and natural gas during 2005, 2006 and 2007, the impacts of derivative financial instruments, including the non-cash mark-to-market impacts, totaled losses of $177.5 million and gains of $198.7 million for the non-GAAP combined 2005 and 2006, respectively, compared to 2007, in which the impacts of derivative financial instruments resulted in a net gain of $26.8 million, which includes $81.6 million as an unrealized loss.

Oil and natural gas sales, production and prices

Total oil and natural gas sales, excluding the impact of derivative financial instruments, for 2007 were $846.1 million compared with $355.8 million for 2006 and $202.9 million for the 2005 non-GAAP combined period. For 2007, natural gas represented 86.2% of our revenues and 91.9% of equivalent production. Both 2006 and 2005 also have natural gas percentages in excess of 80.0% of total revenues and total production. Our equivalent production volumes for 2007 were 121.3 Bcfe compared with 49.6 Bcfe for 2006, an increase of 144.6%, primarily due to our acquisitions. Equivalent production from our 2007 acquisitions represented over 40.8% of 2007 total volumes. Our equivalent production volumes for 2006 were 49.6 Bcfe, or 111.1% greater than the 2005 non-GAAP combined period. The average price per Mcfe, before the impact of derivative financial instruments, was $6.98, $7.17 and $8.62 for 2007, 2006 and the 2005 non-GAAP combined period, respectively.

For 2007, our average price received for natural gas, excluding the impact of derivative financial instruments, was $6.54 per Mcf compared with $6.77 per Mcf in 2006 and $8.58 in the 2005 non-GAAP combined period. The 2007 average price received for oil, also excluding the impacts of derivative financial instruments was $71.17 per Bbl, or 14.3% higher than the 2006 price of $62.27 per Bbl. The average price per Bbl for the 2005 non-GAAP combined period was $53.35. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, estimates of oil and natural gas in storage, weather and other seasonal conditions, including hurricanes and tropical storms. Market conditions involving over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect the volatility to continue in the future. Changes in oil and natural gas prices have a significant impact on our oil and natural gas revenues, cash flows, quantities of estimated Proved Reserves and related liquidity. Assuming our December 2007 production levels, a change of $0.10 per Mcf of natural gas sold would result in an increase or decrease in revenues and cash flow of approximately $11.1 million and a change of $1.00 per Bbl of oil sold would result in an increase or decrease in revenues and cash flow of approximately $1.6 million without considering the effects of derivative financial instruments.

Changes in oil and natural gas volumes from our acquisitions, development drilling and exploitation projects combined with significant price fluctuations significantly impacted our operating revenues and cash flows from operations. In 2007, our revenues (before the impact of derivative financial instruments) increased to $846.1 million from $355.8 million for 2006. The total increase of $490.3 million was attributable to an increase of $492.3 million from increased volumes primarily due to 2006 and 2007 acquisitions. This increase was partially offset by a reduction in our realized price per Mcfe, which lowered revenue by $2.0 million.

The 2006 and 2007 acquisitions significantly increased our presence in the East Texas/North Louisiana and Mid-Continent regions. Following is a summary of production grouped by our significant producing regions for the 2005 non-GAAP combined period and years ended December 31, 2006 and 2007.

	Years ended December 31,					
	Non-GAAP 2005		2006		2007	
Areas	Mmcfe	%	Mmcfe	%	Mmcfe	%
East Texas/North Louisiana	3,518	14.9	17,888	36.1	78,312	64.6
Mid-Continent	994	4.2	9,494	19.1	19,271	15.9
Appalachia	12,892	54.7	15,028	30.3	15,661	12.9
Permian	3,591	15.2	4,725	9.5	7,277	6.0
Rockies	2,553	10.8	2,484	5.0	768	0.6
Total production	23,548	100.0	49,619	100.0	121,289	100.0

In January 2007, we completed the sale of our producing properties and undeveloped drilling locations in the Wattenberg Field area of the DJ Basin, Colorado. This transaction included substantially all of our producing assets in the Rockies area. In May 2007, we sold a group of properties acquired in the Southern Gas Acquisition. While this sale, which provided proceeds of approximately $235.5 million was substantial, it did not impact our results of operations as we did not hold the properties for a period of time sufficient to impact our operating results. In July 2007, we completed the sale of substantially all of our interest in the Cement Field located in our Mid-Continent area. In October 2007, we completed the purchase of an additional 45% ownership interest in approximately 28,000 acres of leasehold interests and 135 producing wells in our Canyon Sand field in West Texas located in our Permian area. We also completed several small sales of producing properties and acreages throughout 2007. The acquisitions of the Vernon Assets and the Southern Gas Assets significantly increased our production in the East Texas/North Louisiana and Mid-Continent areas during 2007.

Derivative financial instruments

Our objective in entering into derivative financial instrument contracts is to manage price fluctuations, protect our returns on investments, and achieve a more predictable cash flow in connection with our acquisition activities and borrowings related to these activities. These transactions limit exposure to declines in prices, but also limit the benefits we would realize if prices increase. When prices for oil and natural gas are volatile, a significant portion of the effect of our derivative financial instrument management activities consists of non-cash income or expenses due to changes in the fair value of our derivative financial instrument contracts. Cash charges or gains only arise from payments made or received on monthly settlements of contracts or if we terminate a contract prior to its expiration.

The following table presents our realized and unrealized gains and losses from derivative financial instruments. We expect that our revenues will continue to be significantly impacted in future periods by changes in the value of our derivative financial instruments as a result of volatility in oil and natural gas prices and the amount of future production volumes subject to derivative financial instruments.

(In thousands)	Predecessor For the 275 day period from January 1, 2005 to October 2, 2005	Successor For the 90 day period from October 3, 2005 to December 31, 2005	Non-GAAP combined 2005	Successor Year ended December 31, 2006	Successor Year ended December 31, 2007	Year to year change 2005-2006(a)	Year to year change 2006-2007
Derivative financial instrument activities:							
Cash settlements on derivative financial instruments	$ (62,842)	$(22,210)	$ (85,052)	$ 29,423	$ 108,413	$114,475	$ 78,990
Non-cash change in fair value of derivative financial instruments	(114,411)	21,954	(92,457)	169,241	(81,606)	261,698	(250,847)
Total derivative financial instrument activities	$(177,253)	$ (256)	$(177,509)	$198,664	$ 26,807	$376,173	$(171,857)

(a) Year to year changes relative to 2005 are calculated using the non-GAAP combined 2005 totals.

The use of derivative financial instruments allow us to limit the impacts of volatile price fluctuations associated with oil and natural gas. The following table presents our natural gas prices, before the impact of derivative financial instruments where average realized prices per Mcfe ranged from a high of $12.06 during the 90 day period from October 3, 2005 to December 31, 2005 to a low of $6.98 during the year ended December 31, 2007 while the impact from realized settlements after the impact of our derivative financial instruments reduced our price volatility from a high of $8.24 per Mcfe during the 90 day period from October 3, 2005 to December 31, 2005 to a range of $7.76 to $7.87 per Mcfe for the years ended December 31, 2006 and 2007, respectively.

(In thousands)	Predecessor For the 275 day period from January 1, 2005 to October 2, 2005	Successor For the 90 day period from October 3, 2005 to December 31, 2005	Non-GAAP combined 2005	Successor Year ended December 31, 2006	Successor Year ended December 31, 2007	Year to year change 2005-2006(a)	Year to year change 2006-2007
Realized pricing:							
Oil per Bbl, before impact of derivative financial instruments	$ 52.07	$ 57.47	$ 53.35	$ 62.27	$ 71.17	$ 8.92	$ 8.90
Natural gas per Mcf, before impact of derivative financial instruments	7.31	12.40	8.58	6.77	6.54	(1.81)	(0.23)
Natural gas equivalent per Mcfe, before impact of derivative financial instruments	7.49	12.06	8.62	7.17	6.98	(1.45)	(0.19)
Effect of cash settlements on derivatives(b)	(0.58)	(3.82)	(1.38)	0.59	0.89	1.97	0.30
Net price per Mcfe, net of derivative financial instruments	$ 6.91	$ 8.24	$ 7.24	$ 7.76	$ 7.87	$ 0.52	$ 0.11

(a) Year to year changes relative to 2005 are calculated using the non-GAAP combined 2005 totals.

(b) The Predecessor period for the 275 day period from January 1, 2005 to October 2, 2005 and the non-GAAP combined 2005 effects exclude $52.6 million of payments made to counterparties to terminate existing derivative financial instruments and enter into new derivative financial instruments contracts at higher underlying product prices.

Our cash settlements for 2007 increased revenue by $108.4 million, or $0.89 per Mcfe compared to $29.4 million, or $0.59 per Mcfe, in 2006. The NYMEX oil and natural gas prices that we used to settle our derivative financial instruments varied significantly during 2006 and 2007.

Our non-cash mark-to-market changes in the value of derivative financial instruments for 2007 resulted in a loss of $81.6 million compared to a gain of $169.2 million in the prior year. The significant fluctuation was, again, attributable to high volatility in the prices for oil and natural gas between each of the years. The ultimate settlement amount of the unrealized portion of the derivative financial instruments is dependent on future commodity prices.

We expect to continue our comprehensive derivative financial instrument program as part of our overall acquisition and financing strategy to enhance our ability to execute our business plan over the entire commodity price cycle, protect our returns on investment, and manage our capital structure. In connection with our acquisitions, we typically hedge a portion of future production acquired in order to lessen the variability of our returns on shareholders' equity and to protect our shareholders' equity by supporting our ability to meet our debt service obligations and stabilize cash flows.

Oil and natural gas operating costs

Operating costs, which include labor, materials and supplies necessary to produce our oil and natural gas, were $117.2 million, or $0.97 per Mcfe for 2007, compared with $46.5 million, or $0.94 per Mcfe for 2006. The increase of $70.7 million is due primarily to $60.6 million of costs associated with the 2006 and 2007 acquisitions, including TXOK, PGMT, Winchester, Vernon and Southern Gas. The per unit increase in cost reflects a general increase in the cost of goods and services for all of our producing areas and an increase in workover activities, which is partially offset by lower per unit operating costs from the Vernon Acquisition due to high production volumes for the properties acquired in the Vernon Acquisition.

Operating costs for 2005 non-GAAP combined period were $20.1 million, or $0.85 per Mcfe, compared with $46.5 million, or $0.94 per Mcfe in 2006. Operating costs per unit increased from 2005 to 2006 due to a general increase in the cost of goods and services for all of our producing areas, including our 2006 acquisitions.

Production and ad valorem taxes

Production and ad valorem taxes were $53.3 million, $22.3 million and $11.0 million for 2007, 2006 and non-GAAP combined 2005, respectively. Production and ad valorem taxes are set by state and local governments and vary as to the tax rate and the value to which the rate is applied. On a percentage of sales basis, our 2007 production and ad valorem taxes were 6.3% of oil and natural gas sales, excluding the impact of derivative financial instruments, compared with 6.3% in 2006 and 5.4% for non-GAAP combined 2005. The change in the consolidated rate in 2006 compared with non-GAAP combined 2005 is due to a higher percentage of revenues from our East Texas/North Louisiana and Mid-Continent producing areas which have a higher combined production and ad valorem tax rates than our Appalachia producing areas.

Depreciation, depletion and amortization

The following table presents our depreciation, depletion and amortization expenses for the 275 day period from January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005, non-GAAP combined 2005, the years ended December 31, 2006 and 2007. The Equity Buyout, which resulted in a change of basis in our oil and natural gas assets, had a significant impact on the depletion rate, which increased to $2.28 per Mcfe for the 90 day successor period from October 3, 2005 to December 31, 2005 from the predecessor period, where the depletion rate was $1.27 per Mcfe. The depreciation, depletion and amortization rate per Mcfe produced varies significantly for each of the periods presented due to our acquisition of TXOK, PGMT and Winchester in 2006, which increased the depreciation, depletion and amortization rate to $2.74 per Mcfe in 2006. The Vernon Acquisition and the Southern Gas Acquisition, which included significant proved developed producing properties, further increased the depreciation, depletion and amortization rate to $3.10 per Mcfe in 2007.

(in thousands)	Predecessor For the 275 day period from January 1, 2005 to October 2, 2005	Successor For the 90 day period from October 3, 2005 to December 31, 2005	Non-GAAP combined 2005	Successor Year ended December 31, 2006	Successor Year ended December 31, 2007	Year to year change 2005-2006(a)	Year to year change 2006-2007
Depreciation, depletion and amortization costs:							
Depletion expense	$ 22,541	$ 13,281	$ 35,822	$129,311	$ 357,902	$ 93,489	$ 228,591
Depreciation and amortization expense	$ 2,146	$ 790	$ 2,936	$ 6,411	$ 17,518	$ 3,475	$ 11,107
Mmcfe produced	17,740	5,808	23,548	49,619	121,289	26,071	71,670
Depletion calculated rate per Mmcfe	$ 1.27	$ 2.28	$ 1.52	$ 2.61	$ 2.95	$ 1.09	$ 0.34
Depreciation and amortization calculated rate per Mmcfe	$ 0.12	$ 0.14	$ 0.13	$ 0.13	$ 0.15	$ —	$ 0.02
Consolidated depreciation, depletion and amortization rate per Mcfe	$ 1.39	$ 2.42	$ 1.65	$ 2.74	$ 3.10	$ 1.09	$ 0.36

(a) Year to year changes relative to 2005 are calculated using the non-GAAP combined 2005 totals.

Accretion of discount on asset retirement obligations increased to $4.9 million in 2007 from $2.0 million in 2006 and $0.8 million in non-GAAP combined 2005. The increase in 2007 from 2006 and in 2006 from non-GAAP combined 2005 is due to the combination of significant well additions and related plugging liabilities in connection with our 2006 and 2007 acquisitions and increased estimates for the costs to plug and abandon properties. The increased estimates for plugging and abandoning properties reflect increased costs for labor, rig rates and materials used in those operations.

General and administrative expenses

The following table presents our general and administrative expenses for the 275 day period from January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005, the twelve months non-GAAP combined 2005, the years ended December 31, 2006 and 2007 and changes for each of the years then ended. The table also reflects significant non-recurring expenses incurred in connection with the October 3, 2005 Equity Buyout.

(in thousands)	Predecessor For the 275 day period from January 1, 2005 to October 2, 2005	Successor For the 90 day period from October 3, 2005 to December 31, 2005	Non-GAAP combined 2005	Successor Year ended December 31, 2006	Successor Year ended December 31, 2007	Year to year change 2005-2006(a)	Year to year change 2006-2007
General and administrative costs:							
Gross general and administrative expense	$ 18,220	$ 7,329	$ 25,549	$ 52,357	$ 88,778	$ 26,808	$ 36,421
Operator overhead reimbursements	(1,291)	(532)	(1,823)	(7,824)	(18,413)	(6,001)	(10,589)
Nonrecurring bonus expense from equity buyout	29,624	—	29,624	—	—	(29,624)	—
Equity buyout non cash—stock based compensation	44,092	—	44,092	—	—	(44,092)	—
Capitalized acquisition, development and exploitation charges	(1,203)	(422)	(1,625)	(3,327)	(5,695)	(1,702)	(2,368)
Net general and administrative expense	$ 89,442	$ 6,375	$ 95,817	$ 41,206	$ 64,670	$(54,611)	$ 23,464
General and administrative expense per Mcfe	$ 5.04	$ 1.10	$ 4.07	$ 0.83	$ 0.53	$ (3.24)	$ (0.30)

(a) Year to year changes relative to 2005 are calculated using the non-GAAP combined 2005 totals.

Net general and administrative expenses for the year ended December 31, 2007 were $64.7 million compared with $41.2 million in 2006, an increase of $23.5 million. Each of the respective years contains significant and notable variances. In 2007, we experienced significant increases in personnel and support facilities related to our 2006 and 2007 acquisitions and our continued efforts to becoming compliant with Sarbanes-Oxley regulations. These increased personnel expenses totaled approximately $18.2 million of increased cash expenses for 2007 and increases of approximately $2.5 million from share-based compensation for 2007. We also incurred approximately $16.5 million for 2007 of legal and project-oriented costs including (i) audit and legal fees in connection with our 2006 and 2007 acquisitions, (ii) costs for implementation and compliance with Section 404 of the Sarbanes-Oxley Act of 2002 and (iii) expenses incurred for conversion of our information technology systems to a common platform.

When comparing 2006 general and administrative costs to non-GAAP combined 2005, general and administrative expenses for non-GAAP combined 2005 include $73.7 million one-time charges related to the Equity Buyout. The decrease in general and administrative expenses from non-GAAP combined 2005 to the year ended December 31, 2006 is partially offset by 2006 acquisition related expenses and Sarbanes-Oxley compliance efforts.

Partially offsetting the increases in general and administrative expenses were operator overhead recoveries of $1.8 million, $7.8 million and $18.4 million for the twelve months non-GAAP combined 2005 and the years ended 2006 and 2007, respectively. Additional offsets to general and administrative expenses were capitalized costs of $1.6 million, $3.3 million and $5.7 million for the non-GAAP combined 2005 and the years ended December 31, 2006 and 2007, respectively.

Stock based and other compensation expense

We adopted the provisions of SFAS No. 123(R) on October 3, 2005 upon closing of the Equity Buyout. Upon closing of the initial public offering, Holdings merged with us and we assumed the EXCO Holdings 2005 Long-Term Incentive Plan, or the 2005 Long-Term Incentive Plan.

During 2007, we issued options to purchase approximately 5.0 million shares of common stock under our 2005 Long-Term Incentive Plan to our employees, which resulted in non-cash compensation expenses of $12.6 million to general and administrative and lease operating expense and $2.4 million of capital charges to our full cost pool.

During 2006, we issued options to purchase approximately 3.6 million shares of common stock to our employees, which resulted in non-cash compensation expenses of $6.5 million to general and administrative expenses and $1.4 million of capital charges to our full cost pool.

Immediately prior to the closing of the Equity Buyout on October 3, 2005, we recorded stock based and other compensation expense for the following items, which are included as part of general and administrative expenses in the 275 day period ended October 2, 2005:

- A non-cash charge of approximately $44.1 million as a result of the acquisition by Holdings II of all of the shares of Class B common stock of EXCO Holdings held by certain members of our management and other employees. The offset to this expense was to additional paid-in capital. The stockholder agreements governing the Class A and Class B common stock of EXCO Holdings provided that, upon the occurrence of certain specified events, including the change of control that occurred upon the Equity Buyout:
  - the holders of the Class A shares would receive the first $175.0 million of proceeds, and
  - the remaining proceeds in excess of the $175.0 million would be allocated on a pro-rata basis to the holders of the Class A shares and the Class B shares. For financial accounting purposes, the Class B shares were considered to be a "variable" plan since a holder of the

shares had to be employed at the date of the change of control to receive fair value for the Class B shares. As a result, we did not recognize compensation expense prior to the consummation of the change of control event.

- A charge of $17.8 million for payments made to holders of options to purchase Class A shares of EXCO Holdings less options held by the EXCO Holdings Employee Stock Participation Plan, or ESPP. This amount was paid to option holders at the time of the Equity Buyout by EXCO Holdings to purchase all stock options outstanding at that time. The amount represented the cumulative difference between the $5.197 per share proceeds for the Class A shares and the exercise price of the outstanding stock options times the number of stock options outstanding.
- A charge of $8.3 million for payments made to our employees who were participants in the ESPP. This amount was paid by EXCO Holdings at the time of the Equity Buyout and was based upon shares of EXCO Holdings Class A and Class B common stock that were reserved, but unissued, for the ESPP. All employees on the date of the Equity Buyout who were not direct owners of EXCO Holdings Class A or Class B common stock received payments under the ESPP. For financial accounting purposes, the ESPP was considered to be a "variable" plan since, to be eligible, a recipient had to be employed at the date of the change of control to receive a payment. As a result, we did not recognize compensation expense prior to the consummation of the change of control event.
- A charge of $2.6 million for accelerated payments made by EXCO Holdings to certain employees of EXCO Resources under the EXCO Holdings Employee Bonus Retention Plan, or the Retention Plan. The Retention Plan was accelerated, paid in full and terminated upon consummation of the Equity Buyout.

During the 90 day period from October 3, 2005 to December 31, 2005, we recorded a non-cash charge of $2.2 million, of which $1.0 million was capitalized as part of our proved oil and natural gas properties as a result of the granting of options to purchase 4,992,650 shares of common stock under the 2005 Long-Term Incentive Plan. The offset to this expense was to shareholders' equity as additional paid-in capital.

Interest expense

Our interest expense for the twelve months ended December 31, 2007 was $181.4 million compared to $84.9 million for the same period in 2006. The increase in interest expense is due to an increase in long-term debt balances in 2006 from $461.8 million at December 31, 2005 to $2.1 billion at December 31, 2006 while our total debt balance remained constant at $2.1 billion throughout 2007. During the last quarter of 2006, our debt increased by more than $1.2 billion. In 2007, this amount was outstanding the full twelve months. Additionally, in 2007 we had expenses related to amendments of our credit agreements along with retirement of debt. The following table presents our interest expense, including charges of $32.1 million attributable to (a) redemption premium of $13.0 million from the retirement of the EPOP Senior Term Credit Agreement, (b) write-off of $12.2 million for unamortized deferred financing costs and unamortized original issue discount on the EPOP Senior Term Credit

Agreement and (c) expensed fees of $6.9 million associated with commitment letters from members of our banking group which were not utilized as a result of the Private Placement on March 30, 2007.

(in thousands)	Predecessor	Successor		Successor			
	For the 275 day period from January 1, 2005 to October 2, 2005	For the 90 day period from October 3, 2005 to December 31, 2005	Non-GAAP combined 2005	Year ended December 31, 2006	Year ended December 31, 2007	Year to year change 2005-2006(a)	Year to year change 2006-2007
Interest expense:							
7¼% senior notes due 2011	$24,615	$ 7,269	$31,884	$29,275	$ 28,922	$(2,609)	$ (353)
JP Morgan bridge loan	—	8,750	8,750	1,216	—	(7,534)	(1,216)
EXCO credit agreements	193	90	283	15,951	29,415	15,668	13,464
Amortization and write-off of deferred financing costs on EXCO facilities	1,618	3,301	4,919	6,789	4,138	1,870	(2,651)
EPOP revolving credit facility	—	—	—	11,937	68,462	11,937	56,525
EPOP term loan	—	—	—	18,827	18,140	18,827	(687)
Amortization and write-off of deferred financing costs on EPOP loans	—	—	—	858	32,100	858	31,242
$50 million senior term loan	245	2	247	—	—	(247)	—
Other interest expense	4	2	6	18	173	12	155
Total interest expense	$26,675	$19,414	$46,089	$84,871	$181,350	$38,782	$96,479

(a) Year to year changes relative to 2005 are calculated using the non-GAAP combined 2005 totals.

Interest expense for the year ended December 31, 2006 was $84.9 million compared with $46.1 million for non-GAAP combined 2005, an increase of $38.8 million, which is primarily attributable to the increase in our overall debt balances in 2006 related to the 2006 acquisitions of TXOK, PGMT and Winchester.

Income taxes

The following table presents a reconciliation of our income tax provision (benefit) for the 275 day period from January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005, and the years ended December 31, 2006 and 2007.

(in thousands)	Predecessor	Successor		
	For the 275 day period from January 1, 2005 to October 2, 2005	For the 90 day period from October 3, 2005 to December 31, 2005	Year ended December 31, 2006	Year ended December 31, 2007
United States federal income taxes (benefit) at statutory rate of 35%	$(70,293)	$ 8,150	$79,925	$38,413
Increases (reductions) resulting from:				
Foreign tax items	644	(2,996)	—	—
Change in U.S. tax law related to Canadian dividend	(2,075)	—	—	—
Adjustments to the valuation allowance	—	—	—	9,336
Non-deductible compensation	15,432	604	1,420	3,144
State taxes net of federal benefit	(6,665)	1,095	8,704	4,423
State tax rate change	—	—	—	3,078
Other	(741)	468	(648)	1,702
Total income tax provision	$(63,698)	$ 7,321	$89,401	$60,096

On February 9, 2005, we repatriated Cdn. $74.5 million ($59.6 million) in an extraordinary dividend from our Canadian subsidiary. We recognized a tax liability of $8.2 million as of December 31, 2004 related to the extraordinary dividend. As a result of certain technical advice issued by the U.S. Treasury Department, we reduced the tax liability by $2.1 million during the second quarter of 2005. EXCO Resources filed amended quarterly reports on Form 10-Q/A that included restated financial statements for the quarters ended June 30, 2005 and September 30, 2005 to reflect the tax benefit in the earlier quarter and to classify the benefit as a component of continuing rather than discontinued operations in the September 30, 2005 quarter. This additional tax benefit is recognized as a component of taxes from continuing operations pursuant to SFAS No. 109 and EITF 93-13, which require that a tax effect of a change in enacted rates be allocated to continuing operations without regard to whether the item giving rise to the effect is a component of discontinued operations.

In June 2005, the state of Ohio enacted new legislation that changed the method of taxing businesses that operate in Ohio. We have significant operations in the state of Ohio through our North Coast subsidiary. As a result of the new tax legislation in Ohio, we recognized a reduction to our deferred tax liability of $5.2 million as of December 31, 2005, which reflects the change in Ohio tax rates and the impacts of our stepped-up basis resulting from the Equity Buyout.

On May 18, 2006, the Texas governor signed into law a Texas Margin tax that replaces the current franchise tax effective January 1, 2007. We had recorded the effect of the change in the tax rate on our existing deferred balances in the second quarter of 2006. Our deferred income tax related to the Texas Margin tax is $0.5 million and $0.9 million at December 31, 2007 and 2006, respectively.

During 2007, our income tax rate was impacted by the substitution of a current federal net operating loss carryback for previously claimed foreign tax credits resulting from the 2005 sale of our Canadian subsidiary. The impact, net of a federal refund of $6.1 million, was an $11.0 million non-cash expense, principally related to foreign tax credits which are required since we no longer have any foreign operations.

Also, as a result of our 2007 acquisitions, our state effective rate increased which required us to change the rate in which we record our deferred tax assets and liabilities. This amount was recognized in our 2007 income tax expense as a current period expense and is presented as part of the Other line item.

On February 10, 2005, we sold our Canadian subsidiary and certain intercompany notes associated with Canada. The aggregate purchase price after contractual adjustments was Cdn. $551.3 million ($443.3 million) less the payment of the outstanding Canadian credit facility of Cdn. $90.1 million ($72.1 million). We have recognized a gain from the sale of our Canadian subsidiary of $175.7 million before income tax expense of $50.1 million related to the gain. The income tax is composed of:

(unaudited, in thousands)	275 day period ended October 2, 2005
U.S. income tax before foreign tax credits	$ 50,128
Canadian income tax on the gain	33,717
U.S. foreign tax credit	(33,788)
Total income tax on gain	$ 50,057

Income taxes from discontinued operations for the 275 day period ended October 2, 2005 reflects the income tax on the gain of $50.1 million as discussed above, an income tax benefit of $1.3 million from our Canadian subsidiary's operations during the period January 1, 2005 to February 10, 2005, and approximately $0.5 million of Canadian income taxes withheld on interest paid by our Canadian subsidiary in 2005 on the intercompany notes.

The loss from discontinued operations of $4.4 million before the gain on the sale of our Canadian subsidiary and income taxes from discontinued operations for the 275 day period ended October 2, 2005 includes:

- approximately $3.8 million in losses from commodity price risk management activities; and
- approximately $2.7 million in severance for employees not hired by the purchaser and management retention bonus payments to certain of our Canadian subsidiary's employees that were accelerated as a result of the sale.

EXCO files income tax returns in the U.S. federal jurisdictions and various state jurisdictions. With few exceptions, EXCO is no longer subject to U.S. federal and state and local examinations by tax authorities for years before 2004. The Internal Revenue Service, or IRS, completed its examination of EXCO's 2004 U.S. federal income tax return in January 2008. The result of the audit was an adjustment between U.S. and our Canadian subsidiary for a hedge recorded to the wrong entity. There was no material change to EXCO's financial position.

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainties in Income Taxes" on January 1, 2007. As a result of the implementation of Interpretation No. 48, the Company recognized a zero liability for unrecognized tax benefits. As of December 31, 2006 and December 31, 2007, the Company's policy is to recognize interest related to unrecognized tax benefits of interest expense and penalties in operating expenses. The Company has not accrued any interest or penalties relating to unrecognized tax benefits in the current financials.

Liquidity, capital resources and capital commitments

General

Most of our growth has resulted from acquisitions and our development and exploitation programs. Consistent with our strategy of acquiring and developing reserves, we have an objective of maintaining financing flexibility. In the past, we have utilized a variety of sources of capital to fund our acquisition, development and exploitation programs and to fund our operations. Our general financial strategy is to use a combination of cash flow from operations, bank financing, cash received from the sale of oil and natural gas properties and the sale or issuance of equity and debt securities to fund our operations, conduct development and exploitation activities and to fund acquisitions. We do not have a set budget for acquisitions as these tend to be opportunity driven. Historically, we have used the proceeds from the issuance of equity and debt securities and borrowings under our credit agreements to raise cash to fund acquisitions. Our ability to borrow from sources other than our credit agreements is subject to restrictions imposed by our lenders. In addition, our Indenture governing our senior notes contains restrictions on incurring indebtedness and pledging our assets. Some of the significant transactions affecting our liquidity to support our growth strategy are discussed below.

In February 2005, we sold our Canadian subsidiary for $443.3 million after contractual adjustments.

On February 14, 2006, we completed an underwritten IPO of 53,615,200 shares of our common stock, including an exercise by the underwriters of their over-allotment option, for aggregate net proceeds to EXCO Resources of $662.2 million. The net proceeds from the IPO, together with cash on hand and additional borrowings under EXCO's credit agreement, were used as follows:

- $360.0 million to repay $350.0 million in principal plus accrued and unpaid interest under the interim bank loan incurred in connection with the Equity Buyout;
- $158.8 million to fund the redemption of the $150.0 million of TXOK preferred stock, plus accumulated and unpaid dividends in connection with the acquisition of ONEOK Energy;

- $375.5 million to repay $171.8 million in principal plus accrued and unpaid interest of $0.9 million under the TXOK credit facility ($137.0 remained outstanding under this facility following the IPO) and $200.0 million in principal plus accrued and unpaid interest of $2.8 million under the TXOK term loan, both loans having been incurred in connection with the acquisition of ONEOK Energy; and
- $6.0 million to pay fees and expenses in connection with the IPO.

On March 30, 2007, we issued 200,000 shares of preferred stock for $2.0 billion in cash in connection with the Vernon Acquisition. In conjunction with the Vernon Acquisition, the Southern Gas Acquisition and the Gulf Coast Sale, we amended our credit agreements which increased our aggregate borrowing base to $2.2 billion. Additional liquidity totaling approximately $495.9 million, net of contractual purchase price adjustments, has been generated from the sale of oil and natural gas properties during 2007.

Net cash provided by operating activities was $577.8 million for the twelve months ended December 31, 2007. At December 31, 2007, our cash and cash equivalents balance was $55.5 million, an increase of $32.7 million from December 31, 2006.

Acquisitions and capital expenditures

The following table presents our capital expenditures and entity acquisitions for the 275 day period from January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005, the non-GAAP combined 2005 and the years ended December 31, 2006 and 2007.

	Predecessor	Successor		Successor	
(in thousands)	For the 275 day period from January 1, 2005 to October 2, 2005	For the 90 day period from October 3, 2005 to December 31, 2005	Non-GAAP combined 2005	Year ended December 31, 2006	Year ended December 31, 2007
Property acquisitions	$103,222	$ —	$103,222	$ 221,103	$ 180,160
Acquisition of TXOK Acquisition, Inc. preferred stock, net of cash acquired	—	—	—	126,489	—
Acquisition of Power Gas Marketing & Transmission, Inc., net of cash acquired, excluded debt and derivative financial instruments assumed	—	—	—	61,776	—
Acquisition of Winchester Energy, Ltd., net of cash acquired	—	—	—	1,094,910	—
Vernon Acquisition	—	—	—	—	1,521,938
Southern Gas Acquisition	—	—	—	—	761,140
Lease purchases	—	—	—	8,991	21,415
Development capital expenditures	39,900	13,194	53,094	194,312	446,675
Corporate and other	5,944	1,712	7,656	10,980	48,399
Total expenditures	$149,066	$14,906	$163,972	$1,718,561	$2,979,727

During 2006, we completed the following acquisitions of oil and natural gas properties and undeveloped acreage, including the acquisition of Winchester. A summary of these acquisitions and their related values to oil and natural gas properties and gathering facilities, net of contractual adjustments is presented on the following table.

(in thousands)	Effective dates	Values allocated
Asset acquisitions:		
West Texas properties from private producer	April 2006	$ 84,925
East Texas properties from private producer	May 2006	50,904
Wyoming properties from private producer	August 2006	27,519
Appalachia properties from private producer	September 2006	49,426
Mid-Continent region and other	Various	8,329
Corporate acquisitions:		
TXOK Acquisition, Inc.	February 2006	569,995
Power Gas Marketing & Transmission, Inc.	April 2006	125,966
Winchester Energy Company, Ltd	October 2006	889,123
Total 2006 acquisitions		$1,806,187

Details of the components of the purchase price and related allocation of the purchase price to the acquired assets and liabilities of our corporate acquisitions in 2006 are as follows:

(in thousands)	TXOK Acquisition, Inc.	Power Gas Marketing & Transmission, Inc.	Winchester Energy Company, Ltd.
Purchase price calculations:			
Carrying value of initial investment in TXOK Acquisition, Inc.	$ 21,531	$ —	$ —
Acquisition of preferred stock, including accrued and unpaid dividends	158,750	—	—
Value of preferred stock redemption premium	4,667	—	—
Cash payments for acquired equity	—	63,615	1,095,028
Assumption of debt:			
Term loan, plus accrued interest	202,755	—	—
Revolving credit facility plus accrued interest	309,701	13,096	—
Assumption of derivative financial instruments	—	38,098	—
Less cash acquired	(32,261)	(1,839)	(118)
Net purchase price	$665,143	$112,970	$1,094,910
Allocation of purchase price:			
Oil and natural gas properties—proved	$489,076	$122,972	$ 583,683
Oil and natural gas properties—unproved	60,840	421	154,291
Gathering and other fixed assets	20,079	2,573	151,149
Goodwill	64,887	21,249	163,935
Current and non-current assets	37,460	2,024	31,872
Deferred income taxes	26,783	(31,424)	—
Accounts payable and other accrued expenses	(30,377)	(3,318)	(39,420)
Asset retirement obligations	(8,203)	(1,527)	(7,793)
Fair value of oil and natural gas derivatives	4,598	—	57,193
Total purchase price allocation	$665,143	$112,970	$1,094,910

On February 14, 2006, at closing of our IPO, we acquired the 89% of TXOK that we did not already own by redeeming their outstanding preferred stock and assuming TXOK's outstanding debt of $512.5 million. The purchase price, net of cash acquired was $665.1 million.

In April and May 2006, we acquired producing properties and undeveloped acreage in West Texas and the Cotton Valley trend in East Texas. The purchase price of these assets was $135.8 million, after contractual adjustments, which was funded with indebtedness drawn under the EXCO Resources Credit Agreement.

On April 28, 2006, we closed an acquisition and acquired 100% of the common stock of PGMT for a net purchase price of $113.0 million. The purchase price included the assumption of $13.1 million of debt and $38.1 million outstanding derivative financial instruments. Upon closing of the transaction, which was funded with indebtedness drawn under the EXCO Resources Credit Agreement, we paid the assumed debt and terminated the assumed commodity hedges.

On October 2, 2006, we closed our acquisition of Winchester and its affiliated entities from Progress Energy, Inc. for approximately $1.1 billion in cash, net of purchase price adjustments. The assets included producing and undeveloped acreage located in the Cotton Valley, Hosston and Travis Peak trends in East Texas and North Louisiana. The assets also include six gathering systems with 300 miles of pipe and a 53-mile pipeline system. The acquisition was financed with a $650.0 million loan under the EPOP Senior Term Credit Agreement and $651.0 million of borrowings under the EPOP Revolving Credit Facility. We formed a new subsidiary to purchase Winchester and that subsidiary became an unrestricted subsidiary as defined under the Indenture governing our senior notes and the EXCO Resources Credit Agreement. Concurrent with the closing of the purchase of Winchester, we contributed to EPOP all of our East Texas properties, with an estimated value of approximately $425.0 million, and related indebtedness of approximately $150.0 million. EPOP is not a guarantor of the EXCO Resources Credit Agreement nor does EXCO Resources guarantee the debt of EPOP.

During 2007, we completed the following acquisitions of oil and natural gas properties and undeveloped acreage, including the Vernon Acquisition and the Southern Gas Acquisition. A summary of these acquisitions and their related values to oil and natural gas properties and gathering facilities, net of contractual adjustments is presented on the following table.

(in thousands)	Vernon Acquisition	Southern Gas Acquisition	Other acquisitions	Consolidated total
Purchase price calculations:				
Purchase price	$1,520,183	$759,100	$180,160	$2,459,443
Acquisition related expenses	1,755	2,040	—	3,795
Total purchase price	$1,521,938	$761,140	$180,160	$2,463,238
Allocation of purchase price:				
Proved oil and natural gas properties	$1,417,823	$577,852	$159,502	$2,155,177
Unproved oil and natural gas properties	58,192	4,743	20,658	83,593
Gulf coast sale	—	235,477	—	235,477
Gas gathering and related facilities	119,409	—	—	119,409
Fair value (liability) of assumed derivative financial instruments	(60,015)	(42,204)	—	(102,219)
Asset retirement obligations	(10,726)	(12,567)	—	(23,293)
Other liabilities, net	(2,745)	(2,161)	—	(4,906)
Total purchase price allocation	$1,521,938	$761,140	$180,160	$2,463,238

On March 30, 2007, EPOP completed the purchase of substantially all of the oil and natural gas properties and assets related to the Vernon and Ansley fields located in Jackson Parish, Louisiana from Anadarko for approximately $1.5 billion in cash, net of purchase price adjustments. Pursuant to the purchase and sale agreement, the purchase price and resulting allocation was finalized during the third quarter of 2007. The Vernon Acquisition was funded by a $1.75 billion capital contribution from EXCO to EPOP. The capital contribution consisted of $1.67 billion in cash and an $80.0 million deposit made by EXCO in December 2006.

On May 2, 2007, we completed the purchase of oil and natural gas properties and related assets, including derivative financial instruments, covering a significant portion of estimated production for 2007, 2008 and 2009 from entities affiliated with Anadarko in multiple fields primarily located in Oklahoma, Texas and Louisiana for approximately $761.1 million in cash, including acquisition related expenses, net of purchase price adjustments, or the Southern Gas Acquisition. The acquisition was funded with cash on hand of $145.2 million, including $133.0 million from escrow accounts from prior sales, borrowings under the EXCO Resources Credit Agreement of $572.9 million and the application of a $43.0 million deposit paid by EXCO to Anadarko in February 2007.

On May 2, 2007, in connection with the Southern Gas Acquisition, EXCO entered into the Second Amended and Restated Credit Agreement, or the EXCO Resources Credit Agreement, among EXCO, as borrower, certain subsidiaries of EXCO, as guarantors, and a group of lenders. As a result of the Southern Gas Acquisition, EXCO and the lenders agreed to increase the borrowing base from $750.0 million to $1.0 billion.

On October 9, 2007, we completed the acquisition of an additional 45.0% interest in 28,000 acres of leasehold interests and 135 producing wells in our Canyon Sand field in West Texas for $155.0 million, subject to customary post-closing purchase price adjustments.

On February 20, 2008, EXCO acquired shallow natural gas properties from EOG Resources, Inc. located primarily in EXCO's central Pennsylvania operating area. The properties include approximately 2,500 producing wells, 2,000 shallow undrilled locations and 16 Mmcfe/d of net production. The purchase price was $395.0 million. After reduction for preliminary closing adjustments of $7.4 million, the net purchase price paid on February 20, 2008 was $387.6 million and was financed with the EXCO Resources Credit Agreement.

2007 divestitures

During 2007, we sold various oil and natural gas properties to multiple purchasers for proceeds totaling approximately $490.3 million.

On January 5, 2007, we completed the sale of oil and natural gas properties and undeveloped drilling locations in the Wattenberg field area of the DJ Basin, or the Wattenberg Field, for approximately $130.9 million in cash, net of contractual adjustments. The transaction included substantially all of the assets EXCO held in the area. Proceeds from the sale were deposited with a third party and used for the Southern Gas Acquisition to facilitate a like-kind exchange for federal income tax purposes.

On May 8, 2007, we completed the sale of a portion of the oil and natural gas properties and related assets in multiple fields primarily located in South Texas and South Louisiana acquired in the Southern Gas Acquisition to an entity affiliated with Crimson Exploration Inc., or Crimson, for an aggregate sale price of $235.5 million in cash, net of preliminary purchase price adjustments, and 750,000 shares of unregistered restricted Crimson common stock, or the Gulf Coast Sale. In connection with the closing of the Gulf Coast Sale, the borrowing base on the EXCO Resources Credit Agreement was reduced from $1.0 billion to $900.0 million.

On July 13, 2007, we completed the sale of substantially all of our interest in the Cement Field, located in Caddo and Grady Counties, Oklahoma in our Mid-Continent area for approximately $99.7 million, after contractual purchase price adjustments. Proceeds from this sale were deposited with a third party intermediary and used to purchase assets in West Texas in October 2007.

In November 2007, we sold certain assets across our portfolio for approximately $20.4 million, subject to post-closing adjustments. Through this divestiture, we exited Nebraska, Colorado, and certain non-operated properties in Texas and the Gulf Coast area of Louisiana.

No gain or loss was recognized from these sales as we use the full cost method of accounting.

Capital budget

We have budgeted $625.2 million for capital expenditures in 2008. We anticipate increasing this amount in light of our recently completed acquisition of properties from EOG Resources, Inc. and for increased activities related to our Marcellus Shale play in Appalachia.

We expect to utilize our current cash balance, cash flow from operations and available funds under our credit agreements to fund our acquisitions, capital expenditures and working capital. We also plan to continue pursuing sales of non-strategic assets to assist with meeting our business objectives.

We believe that our capital resources from existing cash balances, cash flow from operating activities and borrowing capacity under our credit agreements are adequate to meet the cash requirements of our business. However, future cash flows are subject to a number of variables including production volumes, fluctuations in oil and natural gas prices and our ability to service the debt incurred in connection with our acquisitions. If cash flows decline we may be required to reduce our capital expenditure budget which in turn may affect our production in future periods. Our operations and other capital resources may not provide cash in sufficient amounts to maintain or initiate planned levels of capital expenditures. We experienced increased costs for tubular goods and for certain services during 2006 and 2007 and some oil and natural gas producing companies encountered difficulties in contracting for drilling rigs and other services due to high demand. Currently, we do not believe that these conditions have had a significant impact upon our capital expenditures programs or our results of operations. However, if such conditions arise that do affect us, projects may be delayed due to lack of services or materials or we may have to delay projects to stay within our capital budget or available liquidity.

7¼% senior notes due January 15, 2011

At December 31, 2007, $444.7 million in principal was outstanding on our 7¼% senior notes due January 15, 2011, or senior notes. Unamortized premium on the senior notes was $11.0 million. The estimated fair value of the senior notes, based on quoted market prices for the senior notes, was $426.9 million on December 31, 2007.

Interest is payable on the senior notes semi-annually in arrears on January 15 and July 15 of each year. The senior notes mature on January 15, 2011. Prior to January 15, 2007, we may redeem all, but not less than all, of the senior notes in cash at a redemption price equal to 100% of the principal amount of the senior notes plus a premium. We may redeem some or all of the senior notes beginning on January 15, 2007 for the redemption price set forth in the senior notes.

The Indenture governing the senior notes contains covenants which limit our ability and the ability of certain of our subsidiaries to:

- incur or guarantee additional debt and issue certain types of preferred stock;
- pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated debt;
- make investments;
- create liens on our assets;
- enter into sale/leaseback transactions;

- create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to us;
- engage in transactions with our affiliates;
- transfer or issue shares of stock of subsidiaries;
- transfer or sell assets; and
- consolidate, merge or transfer all or substantially all of our assets and the assets of our subsidiaries.

Credit agreements

EXCO Resources Credit Agreement

Effective February 20, 2008, the EXCO Resources Credit Agreement was amended and restated and the borrowing base was increased from $900.0 million to $1.2 billion. All other terms remain unchanged. The borrowing base is redetermined semi-annually with EXCO and the lenders having the right to interim unscheduled redeterminations in certain circumstances. Scheduled redeterminations are on March 1 and September 1 of each year beginning on September 1, 2007. The facility matures on March 30, 2012. The interest rate ranges from London Inter Bank Offered Rate, or LIBOR, plus 100 bps to LIBOR plus 175 bps depending upon borrowing base usage. The facility also includes an Alternate Base Rate, or ABR, pricing alternative ranging from ABR plus 0 bps to ABR plus 75 bps depending upon borrowing base usage. Borrowings under the EXCO Resources Credit Agreement are collateralized by a first lien mortgage providing a security interest in our oil and natural gas properties. EXCO has also agreed to have in place commodity derivative contracts covering no more than 80% of its "forecasted production from total Proved Reserves" (as defined) for the next two years and 70% in the third, fourth and fifth years. EXCO will have in place mortgages covering 80% of the Engineered Value of its Borrowing Base Properties (as defined). The foregoing description is not complete and is qualified in its entirety by the EXCO Resources Credit Agreement. As of December 31, 2007, EXCO was in compliance with the financial covenants contained in the EXCO Resources Credit Agreement, which require that we:

- maintain a Consolidated Current Ratio (as defined) of at least 1.0 to 1.0 as of the end of any fiscal quarter ending on or after September 30, 2007;
- not permit our ratio of Consolidated Funded Indebtedness (as defined) to Consolidated EBITDAX (as defined) to be greater than 3.5 to 1.0 at the end of any fiscal quarter ending on or after September 30, 2007; and
- maintain a Consolidated EBITDAX to Consolidated Interest Expense (as defined) ratio of at least 2.5 to 1.0 at the end of any fiscal quarter ending on or after September 30, 2007.

At December 31, 2007, the six month LIBOR rate was 4.6%, which would result in an interest rate of approximately 5.8%, on any new indebtedness we may incur under the EXCO Resources Credit Agreement. At December 31, 2007, we had a borrowing base of $900.0 million of which $560.5 million was outstanding under the EXCO Resources Credit Agreement. At February 20, 2008, we had $920.5 million outstanding under the EXCO Resources Credit Agreement.

EPOP Credit Agreement

The EPOP Credit Agreement has a borrowing base of $1.3 billion. The borrowing base is scheduled to be redetermined on a semi-annual basis, with EPOP and the lenders having the right to interim unscheduled redeterminations in certain circumstances. Scheduled redeterminations will be made on or about April 1 and October 1 of each year, beginning October 1, 2007. The EPOP Credit

Agreement is secured by a first priority lien on the assets of EPOP, including 100% of the equity of EPOP's subsidiaries, and is guaranteed by all existing and future subsidiaries of EPOP. Effective February 20, 2008, the EPOP Credit Agreement was amended to provide a valuation mechanism with respect to our midstream, pipeline and gathering assets in East Texas/North Louisiana for purposes of setting the borrowing base. EPOP has agreed to have in place derivative financial instruments covering no more than 80.0% of the "forecasted production from total Proved Reserves" (as defined) for the next two years and 70.0% of the forecasted production from total Proved Reserves in the third, fourth and fifth years. The foregoing description is not complete and is qualified in its entirety by the EPOP Credit Agreement. As of December 31, 2007, EPOP was in compliance with the financial covenants contained the EPOP Credit Agreement, which require that EPOP:

- maintain a consolidated current ratio (as defined under the EPOP Credit Agreement) of at least 1.0 to 1.0 at the end of any fiscal quarter, beginning with the quarter ended June 30, 2007;
- not permit our ratio of consolidated indebtedness to consolidated EBITDAX (as defined under the EPOP Credit Agreement) to be greater than 3.5 to 1.0 at the end of each fiscal quarter, beginning with the quarter ended June 30, 2007; and
- not permit our interest coverage ratio (as defined under the EPOP Credit Agreement) to be less than 2.5 to 1.0 at the end of each fiscal quarter, beginning with the quarter ended June 30, 2007.

The EPOP Credit Agreement contains representations, warranties, covenants, events of default, and indemnities customary for agreements of this type. The EPOP Credit Agreement matures March 30, 2012. Interest under the EPOP Credit Agreement ranges from LIBOR plus 100 basis points (bps) to 175 bps or ABR, as defined, ranging from ABR plus 0 bps to ABR plus 75 bps.

At December 31, 2007, the six month LIBOR rate was 4.6%, which would result in an interest rate of approximately 6.1% on any new indebtedness we may incur under the EPOP Credit Agreement. At December 31, 2007, we had a borrowing base of $1.3 billion, of which $1.1 billion was outstanding under the EPOP Credit Agreement. At February 20, 2008, $1.1 billion outstanding under the EPOP Credit Agreement.

Preferred stock

The 7.0% Preferred Stock and Hybrid Preferred Stock were issued in several series at a purchase price of $10,000 per share. As of December 31, 2007, the liquidation preference of the 7.0% Preferred Stock and the Hybrid Preferred Stock was $0.4 billion and $1.6 billion, respectively.

We paid dividends on the 7.0% Preferred Stock and Hybrid Preferred Stock totaling $127.1 million during 2007. We have accrued dividends of $5.8 million as of December 31, 2007. EXCO held its annual meeting of shareholders on August 30, 2007. During this meeting, shareholders voted in favor of the transformation of the Hybrid Preferred Stock into terms identical to the 7.0% Preferred Stock. As a result, the annual dividend requirement on the Hybrid Preferred Stock is reduced from $177.1 million to $112.7 million, a reduction of $64.4 million per annum. Our annual dividends on the 7.0% Preferred Stock and Hybrid Preferred Stock now total $140.0 million.

Derivative financial instruments

We use derivative financial instruments to manage exposure to commodity prices and interest rate risks. Our objectives for holding derivatives are to minimize risks using the most effective methods to eliminate or reduce the impacts of these exposures.

Our production is generally sold at prevailing market prices. However, we periodically enter into derivative financial instrument contracts for a portion of our production when market conditions are deemed favorable and oil and natural gas prices exceed our minimum internal price targets.

Our objective in entering into derivative financial instrument contracts is to manage price fluctuations and achieve a more predictable cash flow associated with our acquisition activities and borrowings under our credit agreements. These transactions limit exposure to declines in prices, but also limit the benefits we would realize if prices increase. As of December 31, 2007, including all contracts entered into through February 22, 2008, we had contracts in place for the volumes and prices shown in the table below, which includes contracts we entered into or assumed in connection with acquisitions.

(in thousands, except prices)	NYMEX gas volume—Mmbtu	Weighted average contract price per Mmbtu	NYMEX oil volume—Bbls	Weighted average contract price per Bbl
Swaps NYMEX:				
Q1 2008	25,485	$8.59	355	$68.27
Q2 2008	26,685	8.27	355	68.23
Q3 2008	26,910	8.29	358	68.20
Q4 2008	26,910	8.39	358	68.16
2009	95,055	8.09	1,215	69.11
2010	37,098	7.94	473	84.85
2011	1,825	4.51	—	—
2012	1,830	4.51	—	—
2013	1,825	4.51	—	—

Off-balance sheet arrangements

None.

Contractual obligations and commercial commitments

The following table presents a summary of our contractual obligations at December 31, 2007:

	Payments due by period				
(in thousands)	Less than one year	One to three years	Three to five years	More than five years	Total
7¼% senior notes(1)	$ —	$ —	$ 444,720	$ —	$ 444,720
EXCO Resources credit agreement(2)	—	—	560,500	—	560,500
EPOP credit agreement(3)	—	—	1,083,000	—	1,083,000
Operating leases(4)	4,172	7,018	4,963	878	17,031
Appalachia property acquisition(5)	348,144	—	—	—	348,144
Drilling/work commitments	26,001	13,401	—	—	39,402
Total contractual cash obligations(6)	$378,317	$20,419	$2,093,183	$878	$2,492,797

(1) Our senior notes are due on January 15, 2011. The annual interest obligation is $32.2 million.

(2) The EXCO Resources Credit Agreement matures on March 30, 2012.

(3) The EPOP Credit Agreement matures on March 30, 2012.

(4) Excludes month-to-month rental expense on compressors.

(5) Represents an executed purchase and sale agreement, dated December 7, 2007, to purchase oil and natural gas properties for $395.0 million, subject to customary closing adjustments. In connection with the execution of the agreement, we paid a $39.5 million deposit, which was

applied to the purchase price at closing on February 20, 2008. On February 20, 2008, preliminary purchase price adjustments from the seller of $7.4 million were applied to reduce the purchase price.

(6) Excludes annual dividends of $140.0 million on our 7.0% Preferred and Hybrid Preferred Stock. Such dividends are payable when, and as, declared by the Board of Directors.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Some of the information below contains forward-looking statements. The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices, interest rates charged on borrowings and earned on cash equivalent investments, and adverse changes in the market value of marketable securities. The disclosure is not meant to be a precise indicator of expected future losses, but rather an indicator of reasonably possible losses. This forward-looking information provides an indicator of how we view and manage our ongoing market risk exposures. Our market risk sensitive instruments were entered into for hedging and investment purposes, not for trading purposes.

Commodity price risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices for natural gas. Pricing for oil and natural gas production is volatile.

The following table sets forth our use of derivative financial instruments activities as of December 31, 2007:

(in thousands, except prices)	Volume Mmbtus/Bbls	Weighted average strike price per Mmbtu/Bbl	Fair value at December 31, 2007
Natural Gas:			
Swaps:			
2008	99,870	$ 8.36	$ 53,993
2009	80,455	7.94	(43,826)
2010	29,798	7.79	(20,794)
2011	1,825	4.51	(5,923)
2012	1,830	4.51	(5,834)
2013	1,825	4.51	(5,618)
Total Natural Gas	215,603		(28,002)
Oil:			
Swaps:			
2008	1,425	68.22	(34,667)
2009	850	60.09	(22,295)
2010	108	59.85	(2,424)
Total Oil	2,383		(59,386)
Total Oil and Natural Gas			$(87,388)

At December 31, 2007, the average forward spot oil prices per Bbl for calendar 2008 and for 2009 were $93.11 and $87.96, respectively, and the average forward spot natural gas prices per Mmbtu for calendar 2008 and for 2009 were $7.81 and $8.52, respectively.

Realized gains or losses from the settlement of derivative financial instruments are recorded in our financial statements as increases or decreases in revenue. For example, using the oil swaps in place at December 31, 2007, if the settlement price exceeds the actual weighted average strike price of $68.22, then a reduction in revenue will be recorded for the difference between the settlement price and $69.22 multiplied by the hedged volume of 1,425 Bbls. Conversely, if the settlement price is less than $68.22, then an increase in revenue will be recorded for the difference between the settlement price and $67.22 multiplied by the hedged volume of 1,425 Bbls. For example, for a hedged volume of 1,425 Bbls, if the settlement price is $69.22, then revenue will be decreased by $1.4 million. Conversely, if the settlement price is $67.22 revenue will be increased by $1.4 million.

Interest rate risk

At December 31, 2007, our exposure to interest rate changes related primarily to borrowings under our credit agreements and interest earned on our short-term investments. The interest rate is fixed at 7¼% on the $444.7 million in senior notes we have outstanding. As of December 31, 2007, we were not using any derivatives to manage interest rate risk. Interest is payable on borrowings under our credit agreements based on a floating rate as more fully described in "Management's discussion and analysis of financial condition and results of operations—Our liquidity, capital resources and capital commitments." At December 31, 2007, we had $560.5 million in outstanding borrowings under the EXCO Resources Credit Agreement. As of February 20, 2008, the outstanding balance under the EXCO Resources Credit Agreement was $920.5 million as of that date, the weighted average interest rate under the EXCO Resources Credit Agreement was 4.40%. A 1% change in interest rates based on the borrowings as of February 20, 2008 would result in an increase or decrease in our interest costs of $9.2 million per year. The interest we pay on these borrowings is set periodically based upon market rates.

The EPOP Credit Agreement bears interest based on a floating rate. As of December 31, 2007, the outstanding balance under the EPOP Credit Agreement was $1.1 billion. As of February 20, 2008, our outstanding balance under the EPOP Credit Agreement was $1.1 billion. As of that date, the weighted average interest rate under the EPOP Credit Agreement was 4.67%. A 1% change in interest rates based on the borrowings as of February 20, 2008 under the EPOP Credit Agreement would result in an increase or decrease in interest costs of $10.7 million per year. The interest we pay on these borrowings is set periodically based upon market rates.

In January 2008, we entered into financial risk management instruments to mitigate our exposure to fluctuations in interest rates on $700.0 million in principal through February 14, 2010 at LIBOR rates ranging from 2.45% to 2.8%.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EXCO RESOURCES, INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Contents

Financial information for the 275 day period from January 1, 2005 to October 2, 2005, represents predecessor (Predecessor) basis financial statements for the period prior to our Equity Buyout transaction. Beginning October 3, 2005, the effective date of the Equity Buyout, the accompanying consolidated financial statements reflect a stepped up (Successor) basis of accounting to reflect the purchase of EXCO Resources by EXCO Holdings. See "Note 1. Organization" to the consolidated financial statements.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

To the Board of Directors and Shareholders of
EXCO Resources, Inc.:

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended). Our internal control over financial reporting is designed to provide reasonable assurance to management and our board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework.* Based on our assessment, we believe that, as of December 31, 2007, our internal control over financial reporting is effective based on those criteria.

The effectiveness of EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2007 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which appears herein.

By: /s/ DOUGLAS H. MILLER

By: /s/ J. DOUGLAS RAMSEY

Dallas, Texas
February 28, 2008

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
EXCO Resources, Inc.:

We have audited EXCO Resources, Inc.'s (the Company) internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). EXCO Resources, Inc.'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 an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit 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. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, EXCO Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of EXCO Resources, Inc. and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the two-year period ended December 31, 2007, and our report dated February 27, 2008 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
February 27, 2008

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
EXCO Resources, Inc.:

We have audited the accompanying consolidated balance sheets of EXCO Resources, Inc. and subsidiaries as of December 31, 2007 and 2006, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the two-year period ended December 31, 2007. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of EXCO Resources, Inc. and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2008 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
February 27, 2008

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
EXCO Resources, Inc.:

In our opinion, the accompanying consolidated statements of operations, of comprehensive income (loss), of shareholders' equity and of cash flows present fairly, in all material respects, the results of operations and cash flows of EXCO Resources, Inc. and its subsidiaries (Predecessor Company) for the period from January 1, 2005 to October 2, 2005 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 audit. We conducted our audit 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 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 audit provides a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, all financial information presented reflects the consolidated results of operations of EXCO Resources, Inc. and its former parent, EXCO Holdings Inc. in order to account for transactions between entities under common control as required by Statement of Financial Accounting Standards No. 141, "Business Combinations".

/s/ PRICEWATERHOUSECOOPERS LLP

Dallas, Texas
May 15, 2006, except for Note 20,
as to which the date is February 28, 2008

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
EXCO Resources, Inc.:

In our opinion, the accompanying consolidated statements of operations, of comprehensive income (loss), of shareholders' equity and of cash flows present fairly, in all material respects, the results of operations and cash flows of EXCO Resources, Inc. and its subsidiaries (Successor Company) for the period from October 3, 2005 to December 31, 2005 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 audit. We conducted our audit 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 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 audit provides a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, all financial information presented reflects the consolidated results of operations of EXCO Resources, Inc. and its former parent, EXCO Holdings Inc. in order to account for transactions between entities under common control as required by Statement of Financial Accounting Standards No. 141, "Business Combinations".

/s/ PRICEWATERHOUSECOOPERS LLP

Dallas, Texas
May 15, 2006, except for Note 20,
as to which the date is February 28, 2008

EXCO Resources, Inc.

Consolidated balance sheet

(in thousands)	December 31, 2006	December 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 22,822	$ 55,510
Accounts receivable:		
Oil and natural gas	84,078	146,297
Joint interest	14,902	21,614
Interest and other	12,199	2,151
Oil and natural gas derivatives	91,614	66,632
Deferred income taxes	—	6,764
Other	11,095	12,332
Total current assets	236,710	311,300
Oil and natural gas properties (full cost accounting method):		
Unproved oil and natural gas properties	297,919	334,803
Proved developed and undeveloped oil and natural gas properties	2,492,863	4,926,053
Accumulated depletion	(142,591)	(500,493)
Oil and natural gas properties, net	2,648,191	4,760,363
Gas gathering assets	203,537	340,706
Accumulated depreciation and amortization	(4,181)	(16,142)
Gas gathering assets, net	199,356	324,564
Office and field equipment, net	14,805	20,844
Advance on pending acquisition	80,000	39,500
Oil and natural gas derivatives	41,469	2,491
Deferred financing costs, net	15,929	20,406
Other assets	520	6,226
Goodwill	470,077	470,077
Total assets	$3,707,057	$5,955,771

See accompanying notes.

EXCO Resources, Inc.

Consolidated balance sheets

(in thousands, except per share and share data)	December 31, 2006	December 31, 2007
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 54,402	$ 106,305
Accrued interest payable	36,000	21,835
Revenues and royalties payable	53,994	100,978
Income taxes payable	89	87
Deferred income taxes payable	32,639	—
Current portion of asset retirement obligations	1,579	1,656
Current portion of long-term debt	6,500	—
Oil and natural gas derivatives	5,721	47,306
Total current liabilities	190,924	278,167
Long-term debt, net of current portion	2,081,653	2,099,171
Asset retirement obligations and other long-term liabilities	57,570	89,810
Deferred income taxes	166,136	271,398
Oil and natural gas derivatives	30,924	109,205
Commitments and contingencies	—	—
7.0% Cumulative Convertible Perpetual Preferred Stock, par value $0.001 per share, 39,008 shares outstanding at December 31, 2007, liquidation preference of $391,218 at December 31, 2007	—	388,574
Hybrid Preferred Stock, par value $0.001 per share, 160,992 shares outstanding at December 31, 2007, liquidation preference of $1,614,616 at December 31, 2007	—	1,603,704
Shareholders' equity:		
Preferred stock, par value $0.001 per share; 10,000,000 shares authorized at December 31, 2007, of which 39,008 shares have been designated as 7.0% Cumulative Convertible Perpetual Preferred Stock and 160,992 shares have been designated as Hybrid Preferred Stock; no shares of preferred stock other than the 7.0% Cumulative Convertible Perpetual and Hybrid Preferred Stock (presented above) are issued and outstanding at December 31, 2007	—	—
Common stock, $0.001 par value; Authorized shares—350,000,000; issued and outstanding shares—104,162,241 at December 31, 2006 and 104,578,941 at December 31, 2007	104	105
Additional paid-in capital	1,024,442	1,043,645
Retained earnings	155,304	71,992
Total shareholders' equity	1,179,850	1,115,742
Total liabilities and shareholders' equity	$3,707,057	$5,955,771

See accompanying notes.

EXCO Resources, Inc.

Consolidated statements of operations

(in thousands, except per share data)	Predecessor: For the 275 day period from January 1, 2005 to October 2, 2005	Successor: For the 90 day period from October 3, 2005 to December 31, 2005	Successor: Year ended December 31, 2006	Successor: Year ended December 31, 2007
Revenues and other income:				
Oil and natural gas	$ 132,821	$70,061	$355,780	$ 846,060
Gain (loss) on derivative financial instruments	(177,253)	(256)	198,664	26,807
Other income	7,096	2,374	5,005	33,643
Total revenues and other income	(37,336)	72,179	559,449	906,510
Cost and expenses:				
Oil and natural gas production (includes $0, $0, $0 and $3.6 million of non-cash compensation expense for the period from January 1, 2005 to October 2, 2005, the period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007, respectively)	22,157	8,949	68,874	170,440
Depreciation, depletion and amortization	24,687	14,071	135,722	375,420
Accretion of discount on asset retirement obligations	617	226	2,014	4,878
General and administrative (includes $44.1 million, $2.2 million, $6.5 million and $9.0 million of non-cash compensation expense for the period from January 1, 2005 to October 2, 2005, the period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007, respectively)	89,442	6,375	41,206	64,670
Interest	26,675	19,414	84,871	181,350
Total cost and expenses	163,578	49,035	332,687	796,758
Equity in net income of TXOK Acquisition, Inc.	—	837	1,593	—
Income (loss) before income taxes	(200,914)	23,981	228,355	109,752
Income tax expense (benefit)	(63,698)	7,631	89,401	60,096
Income (loss) before discontinued operations	(137,216)	16,350	138,954	49,656
Discontinued operations:				
Loss from operations	(4,403)	—	—	—
Gain on disposition of Addison Energy Inc.	175,717	—	—	—
Income tax expense	49,282	—	—	—
Income from discontinued operations	122,032	—	—	—
Net income (loss)	(15,184)	16,350	138,954	49,656
Preferred stock dividends	—	—	—	(132,968)
Net income (loss) available to common shareholders	$ (15,184)	$16,350	$138,954	$ (83,312)
Earnings per share:				
Basic				
Net income (loss) from continuing operations	$ (1.18)	$ 0.35	$ 1.44	$ (0.80)
Net income (loss) available to common shareholders	$ (0.13)	$ 0.35	$ 1.44	$ (0.80)
Weighted average common shares outstanding	116,504	47,222	96,727	104,364
Diluted				
Net income (loss) from continuing operations	$ (1.18)	$ 0.35	$ 1.41	$ (0.80)
Net income (loss) available to common shareholders	$ (0.13)	$ 0.35	$ 1.41	$ (0.80)
Weighted average common and common equivalent shares outstanding	116,504	47,222	98,453	104,364

See accompanying notes.

EXCO Resources, Inc.

Consolidated statements of cash flows

(in thousands)	Predecessor	Successor		
	For the 275 day period from January 1, 2005 to October 2, 2005	For the 90 day period from October 3, 2005 to December 31, 2005	Year ended December 31, 2006	Year ended December 31, 2007
Operating Activities:				
Net income (loss)	$ (15,184)	$ 16,350	$ 138,954	$ 49,656
Income from discontinued operations	(122,032)	—	—	—
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Equity in net income of TXOK Acquisition, Inc.	—	(837)	(1,593)	—
Gain on sale of other assets	(373)	—	(89)	(941)
Depreciation, depletion and amortization	24,687	14,071	135,722	375,420
Stock option compensation expense	44,092	2,207	6,532	12,632
Accretion of discount on asset retirement obligations	617	226	2,014	4,878
Non-cash change in fair value of derivatives	114,410	(21,954)	(169,241)	81,606
Cash settlements of assumed derivative	—	—	—	14,214
Deferred income taxes	(59,467)	15,964	89,401	66,171
Amortization of deferred financing costs, premium on 7¼% senior notes due 2011 and discount on long-term debt	1,320	2,381	4,733	10,332
Gains from sales of marketable securities	3	—	—	—
Effect of changes, net of acquisition effects, in:				
Accounts receivable	(24,512)	(2,533)	24,038	(59,290)
Other current assets	(369)	1,094	(3,727)	(3,092)
Accounts payable and other current liabilities	25,458	(18,792)	915	26,243
Net cash provided by (used in) operating activities of discontinued operations	(69,772)	—	—	—
Net cash provided by (used in) operating activities	(81,122)	8,177	227,659	577,829
Investing Activities:				
Investment in TXOK Acquisition, Inc.	—	(20,000)	—	—
Additions to oil and natural gas properties, gathering systems and equipment	(151,144)	(13,207)	(434,166)	(2,846,969)
Proceeds from disposition of property and equipment	46,010	(393)	5,824	490,362
Payment to TXOK Acquisition, Inc. for preferred stock redemptions, net of cash acquired	—	—	(126,489)	—
Acquisition of Power Gas Marketing & Transmission, Inc., net of cash acquired	—	—	(61,776)	—
Acquisition of Winchester Energy Company, Ltd., net of cash acquired	—	—	(1,094,910)	—
Advance payment on pending acquisition	—	—	(80,000)	(39,500)
Proceeds from sale of Addison Energy Inc., net of cash sold of $1,415	443,397	—	—	—
Advances/investments with affiliates	—	20,000	—	—
Proceeds from sales of marketable securities	59	—	—	5,228
Net cash (provided by) used in investing activities of discontinued operations	(442)	—	—	—
Other investing activities	—	263	—	(5,558)
Net cash provided by (used in) investing activities	337,880	(13,337)	(1,791,517)	(2,396,437)
Financing Activities:				
Proceeds from long-term debt	41,300	9,999	1,884,250	2,235,500
Repayment of interim bank loan	—	—	(350,000)	—
Payments on long-term debt	(148,247)	(15,279)	(776,849)	(2,221,532)
Proceeds from issuance of common stock, net of underwriter's commissions and initial public offering costs	—	—	657,381	4,162
Proceeds from issuance of preferred stock, net of underwriter's commissions and issuance costs	—	—	—	1,992,273
Dividends on preferred stock	—	—	—	(127,134)
Principal and interest on notes receivable-employees	311	1,262	—	—
Settlement of derivative financial instruments on Power Gas Marketing & Transmission, Inc. acquisition	—	—	(38,098)	—
Settlements of derivative financial instruments with a financing element	—	—	—	(14,214)
Deferred financing costs and other	—	—	(16,957)	(17,759)
Net cash provided by (used in) financing activities of discontinued operations	59,601	—	—	—
Net cash provided by (used in) financing activities	(47,035)	(4,018)	1,359,727	1,851,296
Net increase (decrease) in cash	209,723	(9,178)	(204,131)	32,688
Cash at beginning of period	26,408	236,131	226,953	22,822
Cash at end of period	$ 236,131	$226,953	$ 22,822	$ 55,510
Supplemental Cash Flow Information:				
Interest paid	$ 33,099	$ 124	$ 65,378	$ 182,192
Income taxes paid (received)	$ 38,213	$ 15,500	$ —	$ (6,075)
Value of shares issued in connection with redemption of TXOK Acquisition, Inc. preferred stock	$ —	$ —	$ 4,667	$ —
Long-term debt assumed in TXOK Acquisition, Inc. acquisition	$ —	$ —	$ 508,750	$ —
Long-term debt assumed in Power Gas Marketing & Transmission, Inc. acquisition	$ —	$ —	$ 13,096	$ —
Derivative financial instruments assumed in acquisitions	$ —	$ —	$ —	$ (102,219)
Value of common stock—Crimson	$ —	$ —	$ —	$ 4,575
Supplemental non cash investing:				
Capitalized stock compensation	$ —	$ 1,034	$ 1,401	$ 2,411

See accompanying notes.

EXCO Resources, Inc.

Consolidated statements of changes in shareholders' equity

(in thousands)	Common Stock Shares	Common Stock Amount	Additional paid-In capital	Notes receivable—officers and employees	Retained earnings (deficit)	Accumulated other comprehensive income (loss)	Total shareholders' equity
Predecessor:							
Balance, December 31, 2004	127,873	$128	$ 173,804	$(1,573)	$ 10,159	$ 21,367	$ 203,885
Foreign currency translation adjustments	—	—	—	—	—	(21,384)	(21,384)
Unrealized gain on equity investments	—	—	—	—	—	17	17
Principal and interest payable	—	—	—	311	—	—	311
Net loss	—	—	—	—	(15,184)	—	(15,184)
Balance for the 275 day period ended October 2, 2005	127,873	128	173,804	(1,262)	$ (5,025)	—	167,645
Successor:							
Acquisition by Holdings II	50,000	50	350,965	—	—	—	351,015
Stock based compensation	—	—	3,517	—	—	—	3,517
Net income	—	—	—	—	16,350	—	16,350
Balance for the 90 day period ended December 31, 2005	50,000	50	354,482	—	16,350	—	370,882
Issuance of common stock, net of expenses	54,162	54	668,021	—	—	—	668,075
Deferred initial public offering costs	—	—	(6,027)	—	—	—	(6,027)
Share-based compensation	—	—	7,966	—	—	—	7,966
Net income	—	—	—	—	138,954	—	138,954
Balance at December 31, 2006	104,162	104	1,024,442	—	155,304	—	1,179,850
Issuance of common stock	417	1	4,161	—	—	—	4,162
Preferred stock dividends	—	—	—	—	(132,968)	—	(132,968)
Share-based compensation	—	—	15,042	—	—	—	15,042
Net income	—	—	—	—	49,656	—	49,656
Balance at December 31, 2007	104,579	$105	$1,043,645	$ —	$ 71,992	$ —	$1,115,742

See accompanying notes.

EXCO Resources, Inc.

Notes to consolidated financial statements

1. Organization

Unless the context requires otherwise, references in this Annual Report on Form 10-K to "EXCO," "EXCO Resources," "Company," "we," "us," and "our" are to EXCO Resources, Inc., its consolidated subsidiaries and EXCO Holdings Inc., or EXCO Holdings, our former parent company that merged with us on February 14, 2006.

EXCO Resources, Inc., a Texas corporation, was formed in October 1955. We are an independent oil and natural gas company engaged in the acquisition, development and exploitation of onshore North American oil and natural gas properties. We expect to continue to grow by leveraging our management team's experience, exploiting our multi-year inventory of development drilling locations and exploitation projects, and selectively pursuing acquisitions that meet our strategic and financial objectives. We employ the use of debt along with a comprehensive derivative financial instrument program to support our acquisition strategy. This approach enhances our ability to execute our business plan over the entire commodity price cycle, protect our returns on investment, and manage our capital structure. Our operations are focused in key North American oil and natural gas areas including East Texas/North Louisiana, Appalachia, Mid-Continent and Permian. In February 2005, we sold our Canadian subsidiary. As a result, all of our operations include onshore United States oil and natural gas properties and related facilities.

Due to the merger of our parent, EXCO Holdings (formerly EXCO Holdings II), into EXCO Resources on February 14, 2006 concurrent with the closing of our initial public offering, or IPO, all financial information in this Annual Report on Form 10-K contains the consolidated financial position and results of EXCO Resources and EXCO Holdings pursuant to presentation requirements contained in Statement of Financial Accounting Standards, or SFAS, No. 141, "Business Combinations", or SFAS No. 141, for transactions between entities under common control. For comparative purposes pursuant to SFAS No. 141, the prior period financial statements of EXCO Resources present the consolidated operations of EXCO Resources and EXCO Holdings for all periods. As described below, our financial statements contain two separate and distinct bases of accounting.

Predecessor—For the 275 day period from January 1, 2005 to October 2, 2005, financial information presented in our consolidated statements of operations, consolidated statements of cash flows and consolidated statements of shareholders' equity reflect the consolidated information of EXCO Resources and EXCO Holdings, our parent company until October 2, 2005.

Successor—For the 90 day period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007, financial information presented in our consolidated financial statements of operations, statements of cash flows and consolidated statements of shareholders' equity reflect the consolidated information of EXCO Resources and Holdings II, which became our parent company on October 3, 2005 effective when all of the outstanding equity securities of EXCO Holdings was purchased in a private transaction, or the Equity Buyout, and with the acquisition by and merger of Holdings II into EXCO Holdings. The Equity Buyout was accounted for as a purchase pursuant to SFAS No. 141 and resulted in a new basis of accounting. The consolidated balance sheets as of December 31, 2006 and 2007 reflect this new basis of accounting.

In addition, as a result of the redemption of TXOK preferred stock (See "Note 4. Significant transactions—Redemption of preferred stock and consolidation of TXOK") on February 14, 2006, our investment in TXOK Acquisition, Inc., or TXOK, which was accounted for using the equity method of accounting until our redemption of the preferred stock, became a wholly-owned subsidiary.

On February 8, 2006, our registration statement on Form S-1, as amended, was declared effective by the Securities and Exchange Commission, or SEC, pursuant to which we offered 50,000,000 shares of our common stock, par value $.001 per share, at an initial offering price of $13.00 per share, or a net price after underwriting discount of $12.35 per share. Net proceeds from the offering after underwriting discount, but before other expenses, were approximately $617.5 million. Concurrent with the February 14, 2006 closing of the IPO, EXCO Holdings, our parent company, was merged into and with EXCO Resources and EXCO Resources became the surviving company. Shares of stock and stock options of EXCO Holdings were automatically converted into an equal number of like securities of EXCO Resources. Subsequently, the underwriters of our IPO exercised their over-allotment option to purchase an additional 3,615,200 shares of our common stock at $12.35 per share which yielded additional net proceeds of approximately $44.6 million.

The accompanying consolidated balance sheets as of December 31, 2006 and 2007, results of operations, cash flows and changes in shareholders' equity for the 275 day period from January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007 are for EXCO, its subsidiaries, and prior to the IPO, its parent. All intercompany transactions have been eliminated. Certain prior year amounts have been reclassified to conform to the current year presentation.

2. Summary of significant accounting policies

Principles of consolidation

The accompanying consolidated balance sheets as of December 31, 2006 and December 31, 2007 and the results of operations and cash flows for the 90 day period from October 3, 2005 to December 31, 2005 and for the twelve months ended December 31, 2006 and 2007 are for EXCO and its subsidiaries and represent the stepped up accounting basis of the Successor company following the Equity Buyout transaction.

The accompanying results of operations and cash flows for the 275 day period from January 1, 2005 to October 2, 2005 are for EXCO and its subsidiaries and represent the Predecessor company's basis of accounting.

All intercompany transactions and accounts have been eliminated.

Management estimates

In preparing financial statements in conformity with accounting principles generally accepted in the United States, we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses during the reporting periods. The most significant estimates pertain to proved oil and natural gas reserve volumes, future development costs, dismantlement and abandonment costs, share-based compensation expenses, estimates relating to certain oil and natural gas revenues and expenses and the fair market value of assets and liabilities acquired in business combinations, derivatives and equity securities. Actual results may differ from management's estimates.

Cash equivalents

We consider all highly liquid investments with maturities of three months or less when purchased, to be cash equivalents.

Concentration of credit risk and accounts receivable

Financial instruments that potentially subject us to a concentration of credit risk consist principally of cash, trade receivables and our derivative financial instruments. We place our cash with high credit quality financial institutions. We sell oil and natural gas to various customers. In addition, we participate with other parties in the drilling, completion and operation of oil and natural gas wells. The majority of our accounts receivable are due from either purchasers of oil or natural gas or participants in oil and natural gas wells for which we serve as the operator. We have the right to offset future revenues against unpaid charges related to wells which we operate. Oil and natural gas receivables are generally uncollateralized. The allowance for doubtful accounts receivable aggregated $1.9 million and $2.0 million at December 31, 2006 and 2007, respectively. We place our derivative financial instruments with financial institutions and other firms that we believe have high credit ratings. For a discussion of the credit risks associated with our commodity price risk management activities, see "Note 6. Derivative financial instruments."

Derivative financial instruments

In connection with the incurrence of debt related to our acquisition activities, our management has adopted a policy of entering into oil and natural gas derivative financial instruments to protect against commodity price fluctuations and to achieve a more predictable cash flow. SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," or SFAS No. 133, requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met, or exemptions for normal purchases and normal sales as permitted by SFAS No. 133 exist. We do not designate our derivative financial instruments as hedging instruments and, as a result, recognize the change in the derivative's fair value currently in earnings.

Oil and natural gas properties

We use the full cost method of accounting, which involves capitalizing all acquisition, exploration, exploitation and development costs. Once we incur costs, they are recorded in the depletable pool of proved properties or in unproved properties, collectively, the full cost pool. Unproved property costs, which totaled $297.9 million and $334.8 million as of December 31, 2006 and 2007, respectively, are not subject to depletion. We review our unproved oil and natural gas property costs on a quarterly basis, and we expect these costs to be evaluated in one to seven years and transferred to the depletable portion of the full cost pool during that time. The full cost pool is comprised of intangible drilling costs, lease and well equipment and exploration and development costs incurred plus acquired proved and unproved leaseholds.

We calculate depletion using the unit-of-production method. Under this method, the sum of the full cost pool and all estimated future development costs are divided by the total amount of Proved Reserves. This rate is applied to our total production for the period, and the appropriate expense is recorded. We capitalize the portion of general and administrative costs, including share-based compensation, that is attributable to our acquisition, exploration, exploitation and development activities.

At the end of each quarterly period, the unamortized cost of oil and natural gas properties, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from our oil and natural gas properties using current period-end prices discounted at 10%, adjusted for related income tax effects (ceiling test). Until February 10, 2005, this ceiling test calculation was done separately for the United States and for our Canadian subsidiary full cost pools. When computing our ceiling test, we evaluate the limitation at the end of each reporting period date. In the event our capitalized costs exceed the ceiling limitation at the end of the reporting date, we subsequently evaluate the limitation for price changes that occur after the balance sheet to assess impairment as permitted by Staff Accounting Bulletin Topic 12—Oil and Gas Producing Activities. In addition, in July 2007, we sought, and received, an exemption from the SEC to exclude the acquisitions of Winchester, Vernon and Southern Gas from our ceiling test for a period of 12 months from the closing date of each acquisition, provided that we could demonstrate beyond a reasonable doubt that the fair value of the oil and natural gas reserves exceeded their unamortized carrying costs. The exemption related to

Winchester expired October 2, 2007 and therefore was included in our December 31, 2007 ceiling test calculation. The exemption related to Vernon will expire on March 30, 2008 and the exemption related to Southern Gas will expire on May 2, 2008.

Sales, dispositions and other oil and natural gas property retirements are accounted for as adjustments to the full cost pool, with no recognition of gain or loss unless the disposition would significantly alter the amortization rate.

The allocated value of proved properties for the 2007 Acquisitions totaled approximately $2.2 billion, which represented an increase of over 87% to the full cost pool from December 31, 2006. The request for exemption was made because the Company believes the fair value of the 2007 Acquisitions' proved oil and gas properties, in certain cases, can be demonstrated beyond a reasonable doubt to exceed their unamortized costs. The Company's expectation of future prices is principally based on NYMEX futures contracts, adjusted for basis differentials, for a period of five years. After a five year period we have historically elected to use flat pricing as the NYMEX futures contracts become more thinly traded. Generally, the flat price used for the sixth year through the economic life of the property is management's internal long-term price estimate, which is, in large part, based on an extension of the NYMEX pricing. EXCO believes the NYMEX futures contract reflects an independent proxy for fair value.

We recognize that, due to the volatility associated with oil and natural gas prices, a downward trend in market prices could occur. If such a trend were to occur and is deemed to be other than a temporary trend, we would assess the 2007 Acquisitions for impairment during the 2008 exemption period.

The calculation of the ceiling test is based upon estimates of Proved Reserves. There are numerous uncertainties inherent in estimating quantities of Proved Reserves, in projecting the future rates of production and in the timing of development activities. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Full cost ceiling test

As of December 31, 2007, the ceiling test computation resulted in the carrying costs of our unamortized proved oil and natural gas properties, net of deferred taxes, exceeding the December 31, 2007 present value of future net revenues by approximately $206.2 million, of which approximately $112.3 million was attributable to our Vernon and Southern Gas acquisitions, which would have resulted in a net ceiling test impairment of $93.9 million. Even though the December 31, 2007 prices for oil and natural gas indicated impairment, the spot price for natural gas and oil increased on February 22, 2008 to a level sufficient to eliminate the need for a ceiling test write-down.

Gas gathering assets

Gas gathering assets are capitalized at cost and depreciated on a straight line basis over their estimated useful lives of 25 to 40 years.

Office and field equipment

Office and field equipment are capitalized at cost and depreciated on a straight line basis over their estimated useful lives. Office and field equipment useful lives range from 3 to 15 years.

Goodwill

In accordance with SFAS No. 142, "Goodwill and Intangible Assets," or SFAS No. 142, goodwill is not amortized, but is tested for impairment on an annual basis, or more frequently as impairment indicators arise. Impairment tests, which involve the use of estimates related to the fair market value of the business operations with which goodwill is associated, are performed at the end of our fourth quarter. Losses, if any, resulting from impairment tests will be reflected in operating income in the statement of operations. In a February 2005 letter to oil and natural gas companies, the SEC provided guidance concerning the treatment of goodwill in situations when a company sells less than 25% of its proved oil and natural gas reserves in a cost pool. The guidance indicated that such dispositions may trigger a need to evaluate goodwill for impairment under SFAS No. 142. As a result of this guidance, beginning January 1, 2005, we no longer reduce the balance of goodwill for property dispositions of less than 25% of our oil and natural gas reserves unless there is an indication that our goodwill is impaired as a result of the sale.

The following table reflects our balances for goodwill as of December 31, 2005, 2006 and 2007 (in thousands):

Successor:	
Balance as of December 31, 2005	$220,006
Acquisition of TXOK	64,887
Acquisition of Power Gas Marketing and Transmission, Inc.	21,249
Acquisition of Winchester Energy Company, Ltd.	163,935
Balance as of December 31, 2006 and 2007	$470,077

Deferred abandonment and asset retirement obligations

In June 2001, the Financial Accounting Standards Board, or FASB, issued SFAS No. 143, "Accounting for Asset Retirement Obligations," or SFAS No. 143. The statement requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state laws.

The following is a reconciliation of our asset retirement obligations for the periods indicated (in thousands):

	Predecessor	Successor		
	For the 275 day period from January 1, 2005 to October 2, 2005	For the 90 day period from October 3, 2005 to December 31, 2005	For the year ended December 31, 2006	For the year ended December 31, 2007
Asset retirement obligations at beginning of period	$13,247	$14,275	$15,823	$56,149
Activity during the period:				
Adjustment to liability due to purchase of EXCO Resources, Inc. by EXCO Holdings II, Inc. in 2005	—	1,607	—	—
Adjustment to liability due to 2006 acquisitions	—	—	16,954	—
Adjustment to liability due to 2007 acquisitions	—	—	—	23,293
Liabilities incurred during period	1,686	51	21,681	5,127
Liabilities settled during period	(1,275)	(336)	(323)	(5,077)
Accretion of discount	617	226	2,014	4,878
Asset retirement obligations at end of period:	14,275	15,823	56,149	84,370
Less current portion	1,713	1,408	1,579	1,656
Long-term portion	$12,562	$14,415	$54,570	$82,714

We have no assets that are legally restricted for purposes of settling asset retirement obligations.

Revenue recognition and gas imbalances

We use the sales method of accounting for oil and natural gas revenues. Under the sales method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers. Gas imbalances at December 31, 2006 and 2007 were not significant.

Capitalization of internal costs

We capitalize as part of our proved developed oil and natural gas properties a portion of salaries and, beginning in October 2005, related share-based compensation for employees who are directly involved in the acquisition and exploitation of oil and natural gas properties. During the 275 day period from January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007, we have capitalized $1.2 million, $1.5 million, $4.7 million and $8.1 million, respectively. Included in the $1.5 million, the $4.7 million and $8.1 million are $1.0 million, $1.4 million and $2.4 million of share based compensation for the 90 day period from October 3, 2005 to December 31, 2005, the years ended December 31, 2006 and 2007, respectively, resulting from the adoption of SFAS No. 123(R), "Share-Based Compensation," or SFAS No. 123(R), on October 3, 2005. See "Note 13. Stock transactions" for further discussion.

Overhead reimbursement fees

We have classified fees from overhead charges billed to working interest owners, including ourselves, of $1.3 million, $0.5 million, $7.8 million and $18.4 million, for the 275 day period from January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007, respectively, as a reduction of general and administrative expenses in the accompanying consolidated statements of operations. Our share of these charges was \$0.8 million, \$0.3 million, \$5.5 million and \$13.5 million for the 275 day period from January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007, respectively, and are classified as oil and natural gas production costs.

Environmental costs

Environmental costs that relate to current operations are expensed as incurred. Remediation costs that relate to an existing condition caused by past operations are accrued when it is probable that those costs will be incurred and can be reasonably estimated based upon evaluations of currently available facts related to each site.

Income taxes

Income taxes are accounted for using the liability method under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year-end. The effect on deferred taxes for a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

Earnings per share

We account for earnings per share in accordance with SFAS No. 128, "Earnings Per Share", or SFAS No. 128. SFAS No. 128 requires companies to present two calculations of earnings per share, or EPS; basic and diluted. Basic earnings per common share are based on the weighted average number of common shares outstanding during the period. Diluted earnings per common share is computed in the same manner as basic earnings per share after assuming issuance of common stock for all potentially dilutive equivalent shares, whether exercisable or not.

Stock options

On December 16, 2004, FASB issued SFAS No. 123(R); which is a revision of SFAS No. 123, "Accounting for Stock-Based Compensation," or SFAS No. 123. SFAS No. 123(R) supersedes APB 25 and amends SFAS No. 95, "Statement of Cash Flows." Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in our consolidated statements of operations based on their estimated fair values. Pro forma disclosure is no longer an alternative.

EXCO adopted the 2005 Long-Term Incentive Plan, or the 2005 Incentive Plan, which provides for the granting of options to purchase up to 20,000,000 shares of our common stock. New shares will be issued for any stock options exercised. As a result of the new basis in accounting due to the Equity Buyout, we adopted the provisions of SFAS No. 123(R) as of October 3, 2005 in connection with the Equity Buyout. See "Note 14. Stock transactions" for additional information related to the 2005 Incentive Plan. The adoption of SFAS No. 123(R) did not have a cumulative affect on our financial statements as no options were outstanding prior to October 5, 2005.

3. Recent accounting pronouncements

The FASB issued FASB Staff Position 00-19-2 "Accounting for Registration Payment Arrangements," or FSP 00-19-2, on December 21, 2006. FSP 00-19-2 requires contingent obligations to make future payments under a registration payment arrangement to be recognized separately in accordance with SFAS No. 5, "Accounting for Contingencies," or SFAS No. 5. SFAS No. 5 requires that an estimated loss from a loss contingency be accrued if the loss is probable and can reasonably be estimated. Our 7.0% Preferred Stock and Hybrid Preferred Stock contain requirements for EXCO, in certain circumstances, to register shares on behalf of the preferred stockholders. On September 5, 2007, we filed an automatically effective registration statement on Form S-3 with the SEC to register for resale the shares of common stock issuable upon conversion of the Series A-1 7.0% Preferred Stock and the Series A-1 Hybrid Preferred Stock. If such registration deadlines are not met, or a prior registration statement ceases to remain effective, we may be obligated to pay liquidated damages. We adopted FSP 00-19-2 upon issuance of the 7.0% Preferred Stock and the Hybrid Preferred Stock. We do not believe any of the contingencies associated with the registration rights of the preferred stockholders are probable as of December 31, 2007 and therefore are not valued separately at December 31, 2007.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," or SFAS No. 157, which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, or GAAP, and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years for financial instruments. In February 2008, the FASB issued a one year deferral for non-financial assets and liabilities. We adopted SFAS No. 157 for financial assets and liabilities on January 1, 2008. We will adopt SFAS No. 157 for non-financial assets and liabilities on January 1, 2009. The effect of adopting SFAS No. 157 is not expected to have a significant effect on our financial statements.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB Statement No. 115," or SFAS No. 159. SFAS No. 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. The fair value option established by SFAS No. 159 permits all entities to choose to measure eligible items at fair value at specified election dates. Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and as such, was adopted by us on January 1, 2008. The effect of adopting SFAS No. 159 is not expected to have a significant effect on our financial statements.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations," or SFAS No. 141(R). SFAS No. 141(R) replaces SFAS No. 141. SFAS No. 141(R) broadens the scope of business combinations to include bargain purchases, combinations of related companies, provides guidance on measuring goodwill and requires acquisition costs to be separate from the value of assets and liabilities purchased. SFAS No. 141(R) is effective for financial statements issued for fiscal years beginning after December 15, 2008, and as such, will be adopted by us on January 1, 2009. We are currently evaluating the effect of adopting SFAS No. 141(R) on our financial statements.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements," or SFAS No. 160. SFAS No. 160 amends Accounting Research Bulletin 51, or ARB 51. SFAS No. 160 requires the recognition of a noncontrolling interest (minority interest) as equity in the consolidated financial statements separate from the parent's equity. The amount of net income attributable to the noncontrolling interest will be included in consolidated net income on the face of the income statement. It also amends certain of ARB No. 51's consolidation procedures for consistency with the requirements of SFAS No. 141(R). SFAS No. 160 also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. SFAS No. 160 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and as such, will be adopted by us on January 1, 2009. We are currently evaluating the effect of adopting SFAS No. 160 on our financial statements.

4. Significant transactions

Initial public offering

On February 14, 2006, we closed our IPO and subsequently issued 53.6 million shares of our common stock, including shares subsequently issued pursuant to an exercise by the underwriters of their over-allotment option, for net proceeds of $662.2 million. Concurrent with the consummation of the IPO, we advanced $158.8 million to TXOK to redeem the TXOK preferred stock and issued an additional 388,889 shares of our common stock as a redemption premium (see—Redemption of preferred stock and consolidation of TXOK). The redemption of this preferred stock caused TXOK to become our wholly-owned subsidiary. In addition to the redemption of the preferred stock of TXOK, we used proceeds from the IPO, together with cash on hand to repay the interim bank loan, repay the TXOK term loan, repay a portion of TXOK's revolving credit facility and pay fees and expenses incurred in connection with the IPO. Concurrent with the closing of the IPO, EXCO Holdings merged with and into Resources and the shares of stock and stock options of EXCO Holdings were automatically converted into an equal number of like securities of EXCO Resources. As a result, we became the surviving company.

Redemption of preferred stock and consolidation of TXOK

On February 14, 2006, we redeemed all of the outstanding TXOK preferred stock, which represented 90% of the voting rights and an 89% economic interest in TXOK. The redemption price for the TXOK preferred stock was cash in the amount of $150.0 million plus $8.8 million of unpaid dividends at a rate of 15% and 388,889 shares of our common stock. The EXCO common stock issued in connection with the preferred redemption represented the value necessary to produce an overall 23% annualized rate of return on the stated value of the TXOK preferred stock as of the date of redemption pursuant to the terms of the preferred stock agreement. For purposes of calculating the rate of return, the common stock of EXCO was valued at $12.00 as required by the terms of the preferred stock. Once the TXOK preferred stock was redeemed, our acquisition of TXOK, or the TXOK acquisition, was complete and it became our wholly-owned subsidiary. We accounted for the acquisition of TXOK as a step acquisition using the purchase method of accounting and began consolidating its operations effective February 14, 2006. As a result, 89% of the fair value of the assets and liabilities of TXOK was recorded at the redemption date and the remaining 11% was recorded as an adjustment to book value as of the date of the initial investment. The total purchase price of TXOK was $665.1 million representing the redemption of the TXOK preferred stock, the initial investment in TXOK common stock and the assumption of liabilities as detailed below. The allocation of the purchase price to the assets and liabilities acquired, which reflects certain second quarter adjustments to the original fair values assigned to certain current assets, current liabilities and deferred income taxes, are also presented (in thousands).

Purchase price calculation:	
Carrying value of initial investment in TXOK Acquisition, Inc.	$ 21,531
Acquisition of preferred stock, including accrued and unpaid dividends	158,750
Value of preferred stock redemption premium	4,667
Assumption of debt:	
Term loan, plus accrued interest	202,755
Revolving credit facility plus accrued interest	309,701
Less cash acquired	(32,261)
Net purchase price	$665,143
Allocation of purchase price:	
Oil and natural gas properties—proved	$489,076
Oil and natural gas properties—unproved	60,840
Other fixed assets	20,079
Current and non-current assets	37,460
Deferred income taxes	26,783
Goodwill	64,887
Fair value of oil and natural gas derivatives	4,598
Accounts payable and other accrued expenses	(30,377)
Asset retirement obligations	(8,203)
Total purchase price allocation	$665,143

Acquisition of Power Gas Marketing & Transmission, Inc.

On April 28, 2006, our wholly-owned subsidiary, North Coast Energy, Inc., or North Coast, closed an acquisition of 100% of the common stock of Power Gas Marketing & Transmission, Inc., or PGMT, for a purchase price of $115.0 million before contractual adjustments, and a net purchase price of $113.0 million. The purchase price included the assumption of $13.1 million of debt and $38.1 million of derivative financial instruments. Upon closing of the transaction, which was funded with indebtedness drawn under our credit facility, we paid the assumed debt and terminated the assumed derivative financial instruments. The acquisition was accounted for as a purchase in accordance with

SFAS No. 141. The allocation of the purchase price to the assets and liabilities of PGMT is presented on the following table (in thousands).

Purchase price calculation:	
Cash payments for acquired shares and contractual payments	$ 63,615
Assumption of debt including accrued interest	13,096
Assumption of derivative financial instruments	38,098
Less cash acquired	(1,839)
Net purchase price	$112,970
Allocation of purchase price:	
Oil and natural gas properties—proved	$122,972
Oil and natural gas properties—unproved	421
Land, field equipment and other assets	2,573
Current assets	2,024
Goodwill	21,249
Current liabilities	(3,267)
Other liabilities	(51)
Deferred taxes, net	(31,424)
Asset retirement obligations	(1,527)
Total purchase price allocation	$112,970

Winchester Acquisition

On October 2, 2006, our wholly-owned subsidiary, Winchester Acquisition, LLC, or Winchester Acquisition, acquired Winchester Energy Company, Ltd., or Winchester, and its affiliated entities from Progress Fuels Corporation for $1.1 billion in cash which was funded with $1.3 billion of indebtedness incurred by EXCO Partners Operating Partnership, or EPOP, an unrestricted wholly-owned subsidiary of EXCO. For a detailed description of the EPOP debt incurred in connection with the Winchester acquisition, see "Note 7. Long-term debt—EPOP Credit Agreement and EPOP Senior Term Credit Agreement." The acquisition was accounted for as a purchase in accordance with SFAS No. 141. Goodwill of $163.9 million resulted from the acquisition, primarily due to the Company's emphasis in concentrating on assets in the East Texas/North Louisiana producing regions.

The allocation of the purchase price to the assets and liabilities of Winchester is presented on the following table (in thousands):

Purchase price calculation:	
Cash payments for acquired shares of common stock	$1,095,028
Less cash acquired	(118)
Net purchase price	$1,094,910
Allocation of purchase price:	
Oil and natural gas properties—proved	$ 583,683
Oil and natural gas properties—unproved	154,291
Gathering and other fixed assets	151,149
Current and non-current assets	31,872
Fair value of oil and natural gas derivatives	57,193
Goodwill	163,935
Accounts payable and other accrued expenses	(39,420)
Asset retirement obligations	(7,793)
Total purchase price allocation	$1,094,910

Private placement of preferred stock

On March 30, 2007, we completed a private placement, or Private Placement, of an aggregate of $390.0 million of 7.0% Preferred Stock and $1.61 billion of Hybrid Preferred Stock to accredited investors pursuant to the terms and conditions of a Preferred Stock Purchase Agreement dated March 28, 2007. The purchase price for each share was $10,000 (which equaled the liquidation preference per share on March 30, 2007). The issuance and sale of the shares in the Private Placement was exempt from registration under the Securities Act of 1933, or Securities Act, pursuant to Section 4(2) thereof and Regulation D promulgated thereunder.

The net proceeds of the Private Placement were used to fund the purchase price of approximately $1.5 billion for the acquisition on March 30, 2007 of substantially all of the oil and natural gas properties, acreage and related assets, including derivative financial instruments in respect of a significant portion of estimated production for 2007, 2008 and 2009, from Anadarko Petroleum Corporation, or Anadarko, in the Vernon and Ansley Fields located in Jackson Parish, Louisiana, or the Vernon Acquisition, and to repay certain outstanding indebtedness.

The 7.0% Preferred Stock is convertible into shares of our common stock at an initial conversion price of $19.00 per share, subject to anti-dilution adjustments, which equates to each share of 7.0% Preferred Stock being initially convertible into approximately 526.3 shares of our common stock, subject to adjustment for fractional shares. The Hybrid Preferred Stock was not initially convertible into shares of our common stock. Under applicable New York Stock Exchange, or NYSE, rules, shareholder approval is required to issue common stock, or securities convertible into or exercisable for common stock, if (i) such common stock has, or will have upon issuance, 20.0% or more of the voting power outstanding before the issuance, (ii) the number of shares of common stock to be issued is, or will be upon issuance, equal to 20.0% or more of the number of shares of common stock outstanding before the issuance, (iii) such common stock, or securities convertible into or exercisable for common stock, will be issued to a director, officer or substantial security holder of the Company and such securities exceed either a threshold of one percent or, if issued to a substantial security holder who is not a director or officer at a price that is not less than the book and market value of the common stock, five percent of the number of shares of common stock or the voting power outstanding before the issuance or (iv) such issuance will result in a change of control of the Company.

As a result of the NYSE rules, limited time period to fund the Vernon Acquisition and the time required to organize a special meeting of shareholders, we issued 39,008 shares of 7.0% Preferred Stock and 160,992 shares of Hybrid Preferred Stock.

We agreed with the preferred stock investors to seek the shareholder approval required by the NYSE, or NYSE Shareholder Approval, to transform the terms of the Hybrid Preferred Stock into the same terms as the 7.0% Preferred Stock. On August 30, 2007, NYSE Shareholder Approval was obtained and the designations, preferences, limitations and relative voting rights of the Series A-1 Hybrid Preferred Stock and Series A-2 Hybrid Preferred Stock became identical to the designations, preferences, limitations and relative voting rights of the Series A-1 7.0% Preferred Stock and the Series A-2 7.0% Preferred Stock, respectively, including the right to receive dividends at an annual rate of 7.0% and the right to convert into shares of our common stock at an initial conversion price of $19.00 per share, subject to anti-dilution adjustments.

Principal terms of the preferred stock

The following summarizes the principal terms of the 7.0% Preferred Stock and the Hybrid Preferred Stock. This discussion is not complete and is qualified in its entirety by, and should be read in conjunction with, the Statements of Designation establishing each series of the 7.0% Preferred Stock and the Hybrid Preferred Stock, which are filed as exhibits to our Current Report on Form 8-K dated March 28, 2007 and filed with the SEC on April 2, 2007.

Series A-1 7.0% Preferred Stock

The Series A-1 7.0% Preferred Stock has an initial liquidation preference equal to $10,000 per share and is convertible into common stock at a price of $19.00 per share, as may be adjusted in accordance with the terms of the Series A-1 7.0% Preferred Stock. We may force the conversion of the Series A-1 7.0% Preferred Stock at any time if the common stock trades for 20 days within a period of 30 consecutive days at a price (i) above 175% of the then effective conversion price ($33.25 per share at the current conversion price of $19.00 per share) at any time during the 24 months after issuance, (ii) above 150% of the then effective conversion price ($28.50 per share at the current conversion price of $19.00 per share) thereafter through the 48th month after issuance and (iii) above 125% of the then effective conversion price ($23.75 per share at the current conversion price of $19.00 per share) at any time thereafter. Cash dividends will accrue at the rate of 7.0% per annum prior to March 30, 2013 and at the rate of 9.0% per annum thereafter. In lieu of paying cash dividends, we may, under certain circumstances prior to March 30, 2013, pay dividends at a rate of 9.0% per annum by adding the dividends to the liquidation preference of the shares of Series A-1 7.0% Preferred Stock. Upon the occurrence of a change of control, holders of the Series A-1 7.0% Preferred Stock may require us to repurchase their shares for cash at the liquidation preference plus accumulated dividends. Holders of the Series A-1 7.0% Preferred Stock have the right to vote with the holders of common stock, the holders of other series of 7.0% Preferred Stock and the holders of Hybrid Preferred Stock, together as a single class, on all matters submitted to our shareholders (except the election of directors) on an as-converted basis. Holders of Series A-1 7.0% Preferred Stock, Series B 7.0% Preferred Stock, Series C 7.0% Preferred Stock and Series A-1 Hybrid Preferred Stock have the right to separately elect up to four directors, subject to the rights of the holders of Series B 7.0% Preferred Stock and Series C 7.0% Preferred Stock to vote as separate classes to each elect one of such preferred directors. In addition, upon the occurrence of specified defaults in the Statements of Designation for the 7.0% Preferred Stock and the Hybrid Preferred Stock, the holders of the 7.0% Preferred Stock and Hybrid Preferred Stock, voting together as a class, have the right to elect four additional directors, or Default Directors, until such default is cured.

Series B 7.0% Preferred Stock

The Series B 7.0% Preferred Stock has substantially the same rights as the Series A-1 7.0% Preferred Stock, except that the holders of Series B 7.0% Preferred Stock have the right to designate one of the preferred directors and do not have registration rights under the 7.0% Registration Rights Agreement. The Series B 7.0% Preferred Stock is convertible into Series A-1 7.0% Preferred Stock at any time at the election of the holder and will automatically convert into Series A-1 7.0% Preferred Stock when such holder ceases to own an aggregate of 10,000 shares of Series B 7.0% Preferred Stock and/or Hybrid Preferred Stock.

Series C 7.0% Preferred Stock

The Series C 7.0% Preferred Stock has substantially the same rights as the Series A-1 7.0% Preferred Stock, except that the holders of Series C 7.0% Preferred Stock have the right to designate one of the preferred directors and do not have any registration rights under the 7.0% Registration Rights Agreement. The Series C 7.0% Preferred Stock is convertible into Series A-1 7.0% Preferred Stock at any time at the election of the holder and will automatically convert into Series A-1 7.0% Preferred Stock when such holder ceases to own an aggregate of 10,000 shares of Series C 7.0% Preferred Stock and/or Hybrid Preferred Stock.

Series A-1 Hybrid Preferred Stock

Since NYSE Shareholder Approval was obtained on August 30, 2007, the designations, preferences, limitations and relative voting rights of the Series A-1 Hybrid Preferred Stock became identical to the designations, preferences, limitations and relative voting rights of the Series A-1 7.0% Preferred Stock, including the right to dividends and the right to convert into our common stock.

7.0% Preferred Stock Registration Rights Agreement

In connection with the Private Placement, we entered into the 7.0% Registration Rights Agreement with the Preferred Stock investors. The 7.0% Registration Rights Agreement contemplates the registration of the resale of the shares of common stock underlying the 7.0% Preferred Stock and the Hybrid Preferred Stock. The 7.0% Registration Rights Agreement contains customary terms and conditions for a transaction of this type. We agreed to file with the SEC, not later than September 26, 2007, a registration statement to register the offer and sale of the common shares issuable upon conversion of the 7.0% Preferred Stock and the Hybrid Preferred Stock and to use our best efforts to have the registration statement declared effective by March 24, 2008. On September 5, 2007, we filed an automatically effective registration statement on Form S-3 with the SEC to register for resale the shares of common stock issuable upon conversion of the Series A-1 Hybrid Preferred Stock and the Series A-1 7.0% Preferred Stock. If any shares of 7.0% Preferred Stock or Hybrid Preferred are outstanding on March 30, 2011, we agreed to file a registration statement with the SEC by June 28, 2011 registering such shares for resale and to use our best efforts to have such registration statement declared effective by September 26, 2011. If we are unable to meet the deadlines described above, if a registration statement ceases to remain effective or if we restrict sales under a registration statement under certain "blackout provisions" for longer than the contractually permitted period, we must pay liquidated damages at a rate of 0.5% per annum of the liquidation preference applicable to the 7.0% Preferred Stock and the Hybrid Preferred Stock for the first 90 days and thereafter for each subsequent 90-day period at an additional rate of 0.25% up to a maximum of 2.0% per annum during any default period. We also agreed to indemnify holders against certain liabilities under the Securities Act in respect of any such resale registration.

Hybrid Preferred Stock Registration Rights Agreement

In connection with the Private Placement, we entered into a registration rights agreement, or Hybrid Registration Rights Agreement, with the Hybrid Preferred Stock investors. The Hybrid Registration Rights Agreement contemplates the registration of the resale of the shares of Series A-1 Hybrid Preferred Stock. If NYSE Shareholder Approval had not been obtained by September 26, 2007, we would have been required to file a registration statement with the SEC by December 24, 2007, covering the resale prior to such shareholder approval of shares of Hybrid Preferred Stock and to use our best efforts to have the registration statement declared effective by March 24, 2008. The Hybrid Registration Rights Agreement and the obligation of the parties thereunder terminated on August 30, 2007 because NYSE Shareholder Approval was obtained.

Vernon Acquisition

On March 30, 2007, EPOP completed the purchase of substantially all of the oil and natural gas properties and related assets, including derivative financial instruments, covering a significant portion of estimated production for 2007, 2008 and 2009 from entities affiliated with Anadarko in the Vernon and Ansley fields located in Jackson Parish, Louisiana for approximately $1.5 billion in cash, net of final purchase price adjustments. The Vernon Acquisition was funded by a $1.75 billion capital contribution from EXCO to EPOP. The capital contribution consisted of $1.67 billion in cash and application of an $80.0 million deposit paid by EXCO to Anadarko in December 2006.

The allocation of the purchase price to the assets and liabilities of the Vernon Acquisition is presented in the following table (in thousands):

Purchase price calculation:	
Purchase price	$1,520,183
Acquisition related expenses	1,755
Total purchase price	$1,521,938
Allocation of purchase price:	
Oil and natural gas properties—proved	$1,417,823
Oil and natural gas properties—unproved	58,192
Gas gathering and related facilities	119,409
Other liabilities, net	(2,745)
Fair value (liability) of assumed derivative financial instruments	(60,015)
Asset retirement obligations	(10,726)
Total purchase price allocation	$1,521,938

Amended and restated credit agreement of EPOP

Concurrent with the Vernon Acquisition, EPOP entered into an Amended and Restated Credit Agreement, or the EPOP Credit Agreement, among EPOP, as borrower, certain subsidiaries of EPOP, as guarantors, and certain lenders. The initial interest rate was London Inter Bank Offered Rate, or LIBOR, plus 150 basis points with a maximum rate of LIBOR plus 175 basis points. The material changes reflected in the EPOP Credit Agreement included an increase in the borrowing base from $750.0 million to $1.3 billion, principally to reflect the assets acquired in the Vernon Acquisition. EPOP used a portion of the increased borrowing capacity and the remaining cash from EXCO's capital contribution to repay $668.7 million of an existing EPOP term loan, or the Senior Term Credit Facility, which included principal of $650.0 million, accrued interest of $5.7 million and a prepayment premium of $13.0 million. Upon consummation of the Vernon Acquisition and repayment of the Senior Term Credit Facility, approximately $1.1 billion was outstanding under the EPOP Credit Agreement.

Southern Gas Acquisition

On May 2, 2007, we completed the purchase of oil and natural gas properties and related assets, including derivative financial instruments, covering a significant portion of estimated production for 2007, 2008 and 2009, from entities affiliated with Anadarko in multiple fields primarily located in Oklahoma, Texas and Louisiana for approximately $761.1 million in cash, including acquisition related expenses, net of preliminary purchase price adjustments, or the Southern Gas Acquisition. The acquisition was funded with cash on hand of $145.2 million, including $133.0 million from escrow accounts from prior sales, borrowings under the EXCO Resources Credit Agreement of $572.9 million and the application of a $43.0 million deposit paid by EXCO to Anadarko in February 2007. The purchase price allocation will be finalized when purchase price adjustments are agreed to with Anadarko.

The allocation of the preliminary purchase price to the assets and liabilities of the Southern Gas Acquisition is presented in the following table (in thousands):

Purchase price calculation:	
Preliminary purchase price	$759,100
Acquisition related expenses	2,040
Total purchase price	$761,140
Allocation of purchase price:	
Oil and natural gas properties—proved	$577,852
Oil and natural gas properties—unproved	4,743
Gulf Coast Sale	235,477
Other, net	(2,161)
Fair value (liability) of assumed derivative financial instruments	(42,204)
Asset retirement obligations	(12,567)
Total purchase price allocation	$761,140

On May 2, 2007, in connection with the Southern Gas Acquisition, EXCO entered into the Second Amended and Restated Credit Agreement, or the EXCO Resources Credit Agreement, among EXCO, as borrower, certain subsidiaries of EXCO, as guarantors, and a group of lenders. As a result of the Southern Gas Acquisition, EXCO and the lenders agreed to increase the borrowing base from $750.0 million to $1.0 billion.

Gulf Coast Sale

On May 8, 2007, we completed the sale of a portion of the oil and natural gas properties and related assets in multiple fields primarily located in South Texas and South Louisiana acquired in the Southern Gas Acquisition to an entity affiliated with Crimson Exploration Inc., or Crimson, for an aggregate sale price of $235.5 million in cash, net of preliminary purchase price adjustments, and 750,000 shares of unregistered restricted Crimson common stock, or the Gulf Coast Sale. In connection with the closing of the Gulf Coast Sale, the borrowing base on the EXCO Resources Credit Agreement was reduced from $1.0 billion to $900.0 million.

On August 15, 2007, we sold the 750,000 shares of unregistered restricted common stock of Crimson for an aggregate sales price of approximately $5.2 million. We recorded a gain of $0.7 million on the sale, which is included in other income for the year ended December 31, 2007.

Pro forma results of operations

The following table reflects the unaudited pro forma results of operations as though the acquisitions of TXOK, PGMT, Winchester, the Private Placement, the Vernon Acquisition, the Southern Gas Acquisition and the Gulf Coast Sale had occurred on January 1, 2006.

(in thousands, except per share data)	Year ended December 31, 2006	Year ended December 31, 2007
Revenues and other income	$1,430,863	$1,063,492
Net income	335,129	101,697
Preferred stock dividends	(140,000)	(140,000)
Net income (loss) available to common shareholders	$ 195,129	$ (38,303)
Basic earnings (loss) per share	$ 2.02	$ (0.37)
Diluted earnings (loss) per share	$ 1.65	$ (0.37)

The following table reflects the unaudited pro forma results of operations as though our significant 2006 acquisitions of TXOK, PGMT and Winchester had occurred at the beginning of each respective period.

(in thousands except per share data, unaudited)	For the 275 day period from January 1, 2005 to October 2, 2005	For the 90 day period from October 3, 2005 to December 31, 2005
Revenues and other income	$177,774	$207,390
Income (loss) from continuing operations	(133,545)	44,259
Net income (loss)	(87,333)	44,259
Basic earnings (loss) per share	$ (0.84)	$ 0.43
Diluted earnings (loss) per share	$ (0.84)	$ 0.41

5. Other acquisitions and dispositions

Transactions other than TXOK, PGMT and Winchester that occurred during 2006

In April and May 2006, we acquired producing properties and undeveloped acreage in West Texas and the Cotton Valley trend in East Texas in two separate acquisitions. The aggregate purchase price of these assets was $135.8 million, after contractual adjustments, which was funded with indebtedness drawn under our credit agreement.

In August and September 2006, we closed two acquisitions of producing properties and acreage for an aggregate purchase price of $76.9 million, after contractual adjustments, adding properties and acreage in our Appalachia and Rockies areas. We paid $27.5 million for properties located in Wyoming.

For the year ended December 31, 2006, property and other asset sales totaled $5.8 million.

Transactions other than the Vernon Acquisition, the Southern Gas Acquisition and Gulf Coast Sale that occurred during 2007

On January 5, 2007, we completed the sale of oil and natural gas properties and undeveloped drilling locations in the Wattenberg Field area of the DJ Basin, or the Wattenberg Field, for approximately $130.9 million in cash, net of contractual adjustments. The transaction included substantially all of the assets EXCO held in the area. Proceeds from the sale were deposited with a third party intermediary pending closing of the Southern Gas Acquisition to facilitate a like-kind exchange for federal income tax purposes.

On July 13, 2007, we completed the sale of substantially all of our interest in the Cement Field, located in Caddo and Grady Counties Oklahoma, in our Mid-Continent area for approximately $99.7 million, after contractual purchase price adjustments. Proceeds from this sale were deposited with a third party intermediary pending closing of assets purchased in West Texas in October 2007.

No gain or loss was recognized from these sales since we use the full cost method of accounting as the sales do not represent a significant divestiture as defined in full cost accounting rules.

On October 9, 2007, we closed the acquisition of an additional 45% interest in 28,000 acres of leasehold interests and 135 producing wells in our Canyon Sand field in West Texas for $155.0 million from private sellers.

6. Derivative financial instruments

The following table sets forth our oil and natural gas derivatives as of December 31, 2007. The fair values at December 31, 2007 are estimated by us and represent the amount that we would expect to receive or pay to terminate the contracts at December 31, 2007. We have the right to offset amounts we expect to receive or pay among our individual counterparties. As a result, we have offset amounts for financial statement presentation purposes.

(in thousands, except prices)	Volume Mmbtus/Bbls	Weighted average strike price per Mmbtu/Bbl	Fair value at December 31, 2007
Natural Gas:			
Swaps:			
2008	99,870	$ 8.36	$ 53,993
2009	80,455	7.94	(43,826)
2010	29,798	7.79	(20,794)
2011	1,825	4.51	(5,923)
2012	1,830	4.51	(5,834)
2013	1,825	4.51	(5,618)
Total Natural Gas	215,603		(28,002)
Oil:			
Swaps:			
2008	1,425	68.22	(34,667)
2009	850	60.09	(22,295)
2010	108	59.85	(2,424)
Total Oil	2,383		(59,386)
Total Oil and Natural Gas			$(87,388)

At December 31, 2007, the average forward NYMEX oil prices per Bbl for calendar 2008 and 2009 were $93.11 and $87.96, respectively, and the average forward NYMEX natural gas prices per Mmbtu for calendar 2008 and 2009 were $7.81 and $8.52, respectively.

7. Long-term debt

(in thousands)	December 31, 2006	December 31, 2007
Short-term debt:		
Current portion of long-term debt	$ 6,500	$ —
Long term debt:		
EXCO Credit Agreement	$ 339,000	$ 560,500
EPOP Credit Agreement	643,500	1,083,000
EPOP Senior Term Credit Agreement	643,500	—
Unamortized discount on EPOP Senior Term Credit Agreement	(3,180)	—
7¼% senior notes due 2011	444,720	444,720
Unamortized premium on 7¼% senior notes due 2011	14,113	10,951
Total	$2,081,653	$2,099,171

Credit agreements

EXCO Resources Credit Agreement

The EXCO Resources Credit Agreement has a borrowing base of $900.0 million. The borrowing base is redetermined semi-annually with EXCO and the lenders having the right to interim unscheduled redeterminations in certain circumstances. Scheduled redeterminations are on March 1 and September 1 of each year beginning on September 1, 2007. The facility matures on March 30, 2012. The interest rate ranges from LIBOR plus 100 bps to plus 175 bps depending upon borrowing base usage. The facility also includes an Alternate Base Rate, or ABR, pricing alternative ranging from ABR plus 0 bps to ABR plus 75 bps depending upon borrowing base usage. Borrowings under the EXCO Resources Credit Agreement are collateralized by a first lien mortgage providing a security interest in our oil and natural gas properties. EXCO has also agreed to have in place commodity derivative contracts covering no more than 80% of its "forecasted production from total Proved Reserves" (as defined) for the next two years and 70% in the third, fourth and fifth years. EXCO shall have in place mortgages covering 80% of the Engineered Value of its Borrowing Base Properties (as defined). The foregoing description is not complete and is qualified in its entirety by the EXCO Resources Credit Agreement. As of December 31, 2007, EXCO was in compliance with the financial covenants contained in the EXCO Resources Credit Agreement, which require that we:

- maintain a Consolidated Current Ratio (as defined) of at least 1.0 to 1.0 as of the end of any fiscal quarter ending on or after September 30, 2007;
- not permit our ratio of Consolidated Funded Indebtedness (as defined) to Consolidated EBITDAX (as defined) to be greater than 3.5 to 1.0 at the end of any fiscal quarter ending on or after September 30, 2007; and
- maintain a Consolidated EBITDAX to Consolidated Interest Expense (as defined) ratio of at least 2.5 to 1.0 at the end of any fiscal quarter ending on or after September 30, 2007.

At December 31, 2007, the six month LIBOR rate was 4.6%, which would result in an interest rate of approximately 5.8%, on any new indebtedness we may incur under the EXCO Resources Credit Agreement. At December 31, 2007, we had $560.5 million of outstanding indebtedness under the EXCO Resources Credit Agreement.

EPOP Credit Agreement

The EPOP Credit Agreement has a borrowing base of $1.3 billion. The borrowing base is scheduled to be redetermined on a semi-annual basis, with EPOP and the lenders having the right to interim unscheduled redeterminations in certain circumstances. Scheduled redeterminations will be made on or about April 1 and October 1 of each year, beginning October 1, 2007. The EPOP Credit Agreement is secured by a first priority lien on the assets of EPOP, including 100% of the equity of EPOP's subsidiaries, and is guaranteed by all existing and future subsidiaries of EPOP. EPOP has agreed to have in place derivative financial instruments covering no more than 80.0% of the "forecasted production from total Proved Reserves" (as defined) for the next two years and 70.0% of the forecasted production from total Proved Reserves in the third, fourth and fifth years. The foregoing description is not complete and is qualified in its entirety by the EPOP Credit Agreement. As of December 31, 2007, EPOP was in compliance with the financial covenants contained the EPOP Credit Agreement, which require that EPOP:

- maintain a consolidated current ratio (as defined under the EPOP Credit Agreement) of at least 1.0 to 1.0 at the end of any fiscal quarter, beginning with the quarter ended June 30, 2007;
- not permit our ratio of consolidated indebtedness to consolidated EBITDAX (as defined under the EPOP Credit Agreement) to be greater than 3.5 to 1.0 at the end of each fiscal quarter, beginning with the quarter ended June 30, 2007; and
- not permit our interest coverage ratio (as defined under the EPOP Credit Agreement) to be less than 2.5 to 1.0 at the end of each fiscal quarter, beginning with the quarter ended June 30, 2007.

The EPOP Credit Agreement contains representations, warranties, covenants, events of default, and indemnities customary for agreements of this type. The EPOP Credit Agreement matures March 30, 2012. Interest under the EPOP Credit Agreement ranges from LIBOR plus 100 basis points, or bps, to 175 bps or an ABR, as defined, ranging from ABR plus 0 bps to ABR plus 75 bps.

At December 31, 2007, the six month LIBOR rate was 4.6%, which would result in an interest rate of approximately 6.1% on any new indebtedness we may incur under the EPOP Credit Agreement. At December 31, 2007, we had approximately $1.1 billion of outstanding indebtedness under the EPOP Credit Agreement.

EPOP Senior Term Credit Agreement

In connection with the Winchester Acquisition, EPOP entered into the EPOP Senior Term Credit Agreement dated October 2, 2006 (as amended and restated as of October 13, 2006). On March 30, 2007, in connection with the $1.75 billion capital contribution from EXCO and the amendments to the EPOP Credit Agreement, the EPOP Senior Term Credit Agreement was paid in full. Total costs to retire the debt was $668.7 million consisting of $650.0 million of principal, $5.7 million of accrued interest and $13.0 million representing a 2.0% redemption premium pursuant to terms of the EPOP Senior Term Credit Agreement. The $13.0 million redemption premium is reported as a component of interest expense in the consolidated statement of operations for the year ended December 31, 2007. Unamortized deferred financing costs and unamortized original issue discount of $12.2 million associated with the EPOP Senior Term Credit Agreement and $6.9 million of bank fees associated with a commitment letter arrangement entered into to ensure sufficient financing to complete acquisitions from Anadarko were also written off and reported as a component of interest expense as a result of the retirement of this debt.

7¼% senior notes due January 15, 2011

As of December 31, 2007, $444.7 million in principal was outstanding on our 7¼% senior notes due January 15, 2011, or senior notes. Unamortized premium on the senior notes at December 31, 2007 was $11.0 million. The estimated fair value of the senior notes, based on quoted market prices for the senior notes, was $426.9 million on December 31, 2007.

Interest is payable on the senior notes semi-annually in arrears on January 15 and July 15 of each year. The senior notes mature on January 15, 2011. We may redeem some or all of the senior notes beginning on January 15, 2007 for the redemption price set forth in the senior notes.

The indenture governing the senior notes contains covenants, which limit our ability and the ability of our subsidiaries to:

- incur or guarantee additional debt and issue certain types of preferred stock;
- pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated debt;
- make investments;
- create liens on our assets;
- enter into sale/leaseback transactions;
- create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to us;
- engage in transactions with our affiliates;
- transfer or issue shares of stock of subsidiaries;
- transfer or sell assets; and
- consolidate, merge or transfer all or substantially all of our assets and the assets of our subsidiaries.

8. Environmental regulation

Various federal, state and local laws and regulations covering discharge of materials into the environment, or otherwise relating to the protection of the environment, may affect our operations and the costs of our oil and natural gas exploitation, development and production operations. We do not anticipate that we will be required in the foreseeable future to expend amounts material in relation to the financial statements taken as a whole by reason of environmental laws and regulations. Because these laws and regulations are constantly being changed, we are unable to predict the conditions and other factors over which we do not exercise control that may give rise to environmental liabilities affecting us.

9. Commitments and contingencies

We lease our offices and certain equipment. Our rental expenses were approximately $0.6 million, $0.2 million, $1.7 million and $8.8 million for the 275 day period from January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007, respectively. Our future minimum rental payments under operating leases with remaining noncancellable lease terms at December 31, 2007, are as follows (in thousands). The table excludes month-to-month rental expenses on compressors:

	Amount
2008	$ 4,172
2009	3,711
2010	3,307
2011	2,677
2012	2,286
Thereafter	878
Total	$17,031

We regularly enter into agreements with contract drilling companies which commit us to utilize, or to pay for if not utilized, drilling rigs. As of December 31, 2007, the minimum amount that we are obligated to pay under these contracts is $39.4 million.

On October 11, 2006, a putative class action was filed against our subsidiary, North Coast Energy, Inc. The case is styled *PRC Holdings, LLC, et al. v. North Coast Energy, Inc.* and was filed in the Circuit Court of Roane County, West Virginia. This action has been removed to the United States District Court for the Southern District of West Virginia. The action has been brought by certain landowners and lessors in West Virginia for themselves and on behalf of other similarly situated landowners and lessors in West Virginia. The lawsuit alleges that North Coast Energy, Inc. has not been paying royalties to the plaintiffs in the manner required under the applicable leases, has provided misleading documentation to the plaintiffs regarding the royalties due, and has breached various other contractual, statutory and fiduciary duties to the plaintiffs with regard to the payment of royalties. In a case styled *The Estate of Garrison Tawney v. Columbia Natural Resources, LLC* announced in June 2006, the West Virginia Supreme Court held that language such as "at the wellhead" and similar language contained in leases when used in describing how to calculate royalties due lessors was ambiguous and, therefore, should be construed strictly against the lessee. Accordingly, in the absence of express language in a lease that is intended to allocate between a lessor and lessee post-production costs such as the costs of marketing the product and transporting it to the point of sale, no post-production costs may be deducted from the lessor's royalty payment due from the lessee. The claims alleged by the plaintiffs in the lawsuit filed against us are similar to the claims alleged in the *Tawney* case. Plaintiffs are seeking common law and statutory compensatory and punitive damages, interest and costs and other remedies. We are vigorously defending the existing lawsuit. The action is in a very preliminary stage. The preliminary status of the lawsuit leaves the ultimate outcome of this litigation uncertain. We believe that we have substantial defenses to this lawsuit and that the adverse affects from this litigation, if any, are reflected in our financial statements and we do not expect the ultimate outcome of the lawsuit to have a material effect on our financial position, results of operations or cash flows.

In the ordinary course of business, we are periodically a party to lawsuits. We do not believe that any resulting liability from existing legal proceedings, individually or in the aggregate, will have a material adverse effect on our results of operations or financial condition.

10. Employee benefit plans

At December 31, 2007, we sponsored two 401(k) plans for our U.S. employees and match up to 100% of employee contributions based on years of service with us. Our matching contributions of $0.4 million, $0.1 million, $1.1 million and $2.6 million for the 275 day period from January 1, 2005 to October 2, 2005, for the 90 day period from October 3, 2005 to December 31, 2005 and for the years ended December 31, 2006 and 2007, respectively, have been included as general and administrative expense.

11. Bonus retention program

We established a bonus retention program in 2003 to provide an incentive for the employee stockholders to remain employed with the company and its subsidiaries. The program provided for equal quarterly payments to the employee stockholders totaling $1.8 million on an annual basis.

The payments to employee stockholders were to continue for four years unless the employee stockholder voluntarily terminated employment or was dismissed for cause, at which time the payments would cease. On February 10, 2005, in conjunction with the sale of our Canadian subsidiary, the Canadian subsidiary's employee bonus retention plan was terminated and all bonus retention amounts payable, aggregating approximately $1.0 million, were accelerated and paid in full pursuant to the terms of the plan. This amount has been included in the loss from operations of discontinued operations during the 275 day period from January 1, 2005 to October 2, 2005. The Equity Buyout on October 3, 2005 constituted a change of control as defined in the agreement. As a result, the employee bonus retention plan was terminated resulting in an additional charge of $2.6 million. Accordingly, all bonus retention amounts payable, aggregating approximately $2.8 million, were accelerated and paid in full pursuant to the terms of the plan. As a result, we have included this amount in general and administrative expense related to this program during the 275 day period from January 1, 2005 to October 2, 2005.

12. Earnings per share

The following table presents basic and diluted earnings (loss) per share for 275 day period from January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007 (in thousands, except per share amounts):

	Predecessor	Successor		
	For the 275 day period from January 1, 2005 to October 2, 2005	For the 90 day period from October 3, 2005 to December 31, 2005	Year ended December 31, 2006	Year ended December 31, 2007
Basic earnings per share:				
Income (loss) from continuing operations available to common shareholders	$(137,216)	$16,350	$138,954	$(83,312)
Income from discontinued operations	122,032	—	—	—
Net income available to common shareholders	$ (15,184)	$16,350	$138,954	$(83,312)
Shares:				
Weighted average number of common shares outstanding	116,504	47,222	96,727	104,364
Basic earnings (loss) per share:				
Continuing operations	$ (1.18)	$ 0.35	$ 1.44	$ (0.80)
Discontinued operations	1.05	—	—	—
Total basic earnings per share	$ (0.13)	$ 0.35	$ 1.44	$ (0.80)
Diluted earnings per share:				
Income (loss) from continuing operations available to common shareholders	$(137,216)	$16,350	$138,954	$(83,312)
Income from discontinued operations	122,032	—	—	—
Net income available to common shareholders	$ (15,184)	$16,350	$138,954	$(83,312)
Shares:				
Weighted average number of common shares outstanding	116,504	47,222	96,727	104,364
Dilutive effect of stock options	—	—	1,726	—
Weighted average common shares and common stock equivalents	116,504	47,222	98,453	104,364
Diluted earnings (loss) per share:				
Continuing operations	$ (1.18)	$ 0.35	$ 1.41	$ (0.80)
Discontinued operations	1.05	—	—	—
Total diluted earnings per share	$ (0.13)	$ 0.35	$ 1.41	$ (0.80)

As a result of the loss from continuing operations for the 275 day period from January 1, 2005 to October 2, 2005 and the year ended December 31, 2007, the potential common stock equivalents from the assumed conversion of stock options of 8,801,351 and 2,619,522, respectively, have been excluded from the diluted EPS calculation. Also excluded from the 2007 diluted earnings per share are 105,263,158 shares of common stock from the assumed conversion of the 7.0% Preferred Stock and Hybrid Preferred Stock as their effect is antidilutive. For financial accounting purposes, the Class B shares of Holdings for the 275 day period from January 1, 2005 to October 2, 2005, were considered to be a "variable" plan since a holder of the shares had to be employed at the date of a change in control to receive fair value for the Class B shares. As a result, the Class B shares have been excluded from per share calculations as required under SFAS No. 128.

13. Stock transactions

Stock options

All of the issued and outstanding EXCO Holdings stock options as of October 3, 2005 were purchased as a part of the Equity Buyout transaction. This resulted in a charge of $17.8 million to general and administrative expense during the 275 day period from January 1, 2005 to October 2, 2005.

We adopted SFAS No. 123(R) on October 3, 2005. As required by SFAS No. 123(R), the granting of options to our employees under the 2005 Long-Term Incentive Plan, or the 2005 Incentive Plan, are share-based payment transactions and are to be treated as compensation expense by us with a corresponding increase to additional paid-in capital.

The 2005 Incentive Plan provides for the granting of options to purchase up to 20,000,000 shares of EXCO's common stock. The options expire ten years following the date of grant and have a weighted average remaining life of 8.79 years. Pursuant to the 2005 Incentive Plan, 25% of the options vest immediately with an additional 25% to vest on each of the next three anniversaries of the date of the grant. We generally grant incentive stock options.

On August 30, 2007, shareholder approval was obtained to increase the number of shares authorized to be issued under the 2005 Incentive Plan by an additional 10,000,000 shares to a total of 20,000,000 shares. Therefore, as of December 31, 2006 and 2007, there were 1,574,475 and 7,022,375 shares available to be granted under the 2005 Incentive Plan, respectively.

The following table summarizes stock option activity related to our employees under the 2005 Incentive Plan:

	Stock options	Weighted average exercise price per share	Weighted average remaining terms (in years)	Aggregate intrinsic value (in thousands)
Options outstanding at October 3, 2005	—	$ —		
Granted	4,992,650	7.50		
Forfeitures	19,575	7.50		
Exercised	—	—		
Options outstanding at December 31, 2005	4,973,075	7.50		
Granted	3,615,700	14.02		
Forfeitures	163,250	8.83		
Exercised	158,152	7.97		
Options outstanding at December 31, 2006	8,267,373	10.32		
Granted	4,951,700	14.94		
Forfeitures	399,600	13.83		
Exercised	416,700	9.99		
Options outstanding at December 31, 2007	12,402,773	$12.06	8.79	$45,220
Options exercisable at December 31, 2007	5,993,786	$10.71	8.42	$29,313

The weighted average grant date fair value of stock options granted during the years 2005, 2006 and 2007 were $2.29, $4.75 and $5.43, respectively. The total intrinsic value of stock options exercised for the 90 day period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007 was $0, $0.9 million and $2.9 million, respectively.

The following summarizes the status of the nonvested stock options as of December 31, 2007 and changes for the year ended December 31, 2007:

	Number of shares	Weighted average grant date fair value
Nonvested at January 1, 2007	5,087,899	$3.59
Granted	4,951,700	5.43
Forfeitures	(399,600)	4.72
Vested	(3,231,012)	4.08
Nonvested at December 31, 2007	6,408,987	$4.65

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model. Options are granted at the fair market value of the common stock on the date of grant. The following assumptions were used for the options included in the above table:

	2005	2006	2007
Expected life	4 years	4 years	4–6 years
Risk-free rate of return	4.22%	4.22%–5.13%	3.28%–4.97%
Volatility	30.40%	30.40%–35.58%	35.67%–37.72%
Dividend yield	0%	0%	0%

As required by SFAS No. 123(R), the granting of options under the 2005 Incentive Plan to our employees are share-based payment transactions and are to be treated as compensation expense by us with a corresponding increase to additional paid-in capital. Expected life was determined based on exercise history, as well as five comparable public companies. Risk-free rate of return is a rate of a similar term U.S. Treasury zero coupon bond. Volatility was determined based on the weighted average of historical volatility of our common stock and the daily closing prices from five comparable public companies. Total share-based compensation for the 90 day period from October 1, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007 was $3.2 million, $7.9 million and $15.0 million, of which $2.2 million, $6.5 million and $12.6 million is included in general and administrative and lease operating expense and $1.0 million, $1.4 million and $2.4 million was capitalized as part of proved developed and undeveloped oil and natural gas properties, respectively, as discussed in "Note 2. Summary of significant accounting policies." The total tax benefit for the 90 day period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007 was $0.2 million, $0.9 million and $1.1 million, respectively. Total share-based compensation to be recognized on unvested awards is $24.2 million over a weighted average period of 1.45 years as of December 31, 2007.

The Class B common stock issued in July 2003 was considered to be a "variable" plan for financial reporting purposes. As a result, we recognized a non-cash charge of approximately $44.1 million during the 275 day period from January 1, 2005 to October 2, 2005 related to the Class B common stock.

14. Income taxes

The income tax provision attributable to our income (loss) before income taxes consists of the following:

(in thousands)	Predecessor	Successor		
	For the 275 day period from January 1, 2005 to October 2, 2005	For the 90 day period from October 3, 2005 to December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2007
Current:				
U.S.				
Federal	$ (3,563)	$(7,020)	$ —	$(6,075)
State	(668)	(1,315)	—	—
Total current income tax (benefit)	(4,231)	(8,335)	—	(6,075)
Deferred:				
U.S.				
Federal	(49,881)	12,949	80,697	61,748
State	(9,586)	3,017	8,704	4,423
Canadian	—	—	—	—
Total deferred income tax (benefit)	(59,467)	15,966	89,401	66,171
Total income tax (benefit)	$(63,698)	$ 7,631	$89,401	$60,096

We have net operating loss carryforwards, or NOLs, for United States income tax purposes that have either been generated from our operations or were purchased in our acquisitions. Our ability to use the purchased NOLs has been restricted by Section 382 of the Internal Revenue Code due to ownership changes which occurred on December 19, 1997 and July 29, 2003, the change in ownership of Rio Grande, Inc. which occurred on March 16, 1999, as well as the Equity Buyout, which occurred on October 3, 2005. In addition, we experienced another change in control on August 30, 2007 based upon the transformation of the Hybrid Preferred Stock to the same terms as the 7.0% Preferred Stock, but the result is no limitation on current year net operating losses. We estimate that approximately $8.5 million of the NOLs limited by Section 382 will expire prior to their utilization. Expiration is expected to occur from 2007 through 2016. Our NOL available for utilization at December 31, 2007 is approximately $29.0 million.

On February 9, 2005, we repatriated Cdn. $74.5 million ($59.6 million) in an extraordinary dividend from our Canadian subsidiary. We recognized a tax liability of $8.2 million as of December 31, 2004 related to the extraordinary dividend. As a result of certain technical advice issued by the U.S. Treasury Department, we reduced the tax liability by $2.1 million during the second quarter of 2005. EXCO Resources filed amended quarterly reports on Form 10-Q/A that included restated financial statements for the quarters ended June 30, 2005 and September 30, 2005 to reflect the tax benefit in the earlier quarter and to classify the benefit as a component of continuing rather than discontinued operations in the September 30, 2005 quarter. This additional tax benefit is recognized as a component of taxes from continuing operations pursuant to SFAS No. 109, "Accounting for Income Taxes," or SFAS No. 109, and EITF 93-13, "Effect of a Retroactive Change in Enacted Tax Rates that is Included in Income from Continuing Operations,", or EITF 93-13, which require that a tax effect of a change in enacted rates be allocated to continuing operations without regard to whether the item giving rise to the effect is a component of discontinued operations.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of our deferred tax liabilities and assets are as follows:

(in thousands)	December 31, 2006	December 31, 2007
Current deferred tax assets (liabilities):		
Basis difference in fair value of derivative financial instruments	$ (32,639)	$ 6,764
Other	—	—
Total current deferred tax assets (liabilities)	(32,639)	6,764
Long-term deferred tax assets:		
Net operating loss and AMT credits carryforwards—U.S	48,654	11,642
Basis difference in fair value of derivative financial instruments	32,684	53,099
Purchase accounting adjustment to bond premium	9,511	9,233
Share-based compensation	1,234	2,257
Foreign tax credits carryforwards	—	9,336
Other	118	30
Total long-term deferred tax assets	92,201	85,597
Valuation allowance	—	(9,336)
Net total long-term deferred tax assets	92,201	76,261
Long-term deferred tax liabilities:		
Book basis of oil and natural gas properties in excess of tax basis—U.S	(258,337)	(347,659)
Taxes on undistributed earnings of foreign subsidiary—U.S	—	—
Total deferred liabilities	(258,337)	(347,659)
Net noncurrent deferred tax liabilities	$(166,136)	$(271,398)

A reconciliation of our income tax provision (benefit) computed by applying the statutory United States federal income tax rate to our income (loss) before income taxes for the 275 day period from

January 1, 2005 to October 2, 2005, the 90 day period from October 3, 2005 to December 31, 2005 and the years ended December 31, 2006 and 2007 is presented in the following table:

	Predecessor	Successor		
(in thousands)	For the 275 day period from January 1, 2005 to October 2, 2005	For the 90 day period from October 3, 2005 to December 31, 2005	Year ended December 31, 2006	Year ended December 31, 2007
United States federal income taxes (benefit) at statutory rate of 35%	$(70,293)	$ 8,150	$79,925	$38,413
Increases (reductions) resulting from:				
Foreign tax items	644	(2,996)	—	—
Change in U.S. tax law related to Canadian dividend	(2,075)	—	—	—
Adjustments to the valuation allowance	—	—	—	9,336
Non-deductible compensation	15,432	604	1,420	3,144
State taxes net of federal benefit	(6,665)	1,095	8,704	4,423
State tax rate change	—	—	—	3,078
Other	(741)	468	(648)	1,702
Total income tax provision	$(63,698)	$ 7,321	$89,401	$60,096

During 2007, our income tax rate was impacted by the substitution of a current federal net operating loss carryback for previously claimed foreign tax credits resulting from the 2005 sale of our Canadian subsidiary. The impact, net of a federal refund of $6.1 million, was an $11.0 million non-cash expense, principally related to foreign tax credits which are required since we no longer have any foreign operations.

Also, as a result of our 2007 acquisitions, our state effective rate increased which required us to change the rate in which we record our deferred tax assets and liabilities. This amount was recognized in our 2007 income tax expense as a current period expense and is presented as part of the Other line item in the above table.

15. Related party transactions

TXOK acquisition

On February 14, 2006, TXOK became our wholly-owned subsidiary and the accounts under the related party arrangements were settled. Also on this date, in connection with our IPO, EXCO advanced TXOK $158.8 million to redeem its preferred stock and TXOK became our wholly-owned subsidiary. The TXOK preferred stock had full voting rights to vote with the TXOK common stock on all matters submitted to a vote by stockholders. Accordingly, holders of the TXOK preferred stock held voting control of TXOK prior to the February 14, 2006 redemption. If the TXOK preferred stock was not redeemed on or before September 27, 2006, the TXOK preferred stock and accumulated dividends would have automatically converted into common stock representing 90% of the outstanding common stock of TXOK. We used the equity method of accounting for our investment in TXOK until February 14, 2006, when TXOK became a wholly-owned subsidiary.

Corporate use of personal aircraft

We periodically charter, for company business, a jet aircraft from DHM Aviation, LLC, a company owned by Douglas H. Miller, our chairman and chief executive officer. The Board of Directors has adopted a written policy covering the use of this aircraft. The Company believes that prudent use of a chartered private airplane by our senior management while on company business can promote efficient use of management time. Such usage can allow for unfettered, confidential communications among management during the course of the flight and minimize airport commuting and waiting time, thereby promoting maximum use of management time for company business. However, we restrict the use of the aircraft to priority company business being conducted by senior management in a manner that is cost effective for us and our shareholders. As a result, EXCO's reimbursed use of the aircraft is restricted to company business. Such use must be approved in advance by our President and our Chief Financial Officer. We maintain a detailed written log of such usage specifying the company personnel (and others, if any) that fly on the aircraft, the travel dates and destination(s), and the company business being conducted. In addition, the log contains a detail of all charges paid or reimbursed by us with supporting written documentation.

In the event the aircraft is chartered for a mixture of company business and personal use, all charges will be reasonably allocated between company reimbursed charges and charges to the person using the aircraft for personal use.

At least annually, and more frequently if requested by the Audit Committee, our Director of Internal Audit surveys fixed base operators and other charter operators located at Dallas Love Field, Dallas, Texas to ascertain hourly flight rates for aircraft of comparable size and equipment in relation to the aircraft. This survey also ascertains other charges (including fuel surcharges) invoiced by such charter operators as well as out-of-pocket reimbursement policies. Such survey is supplied to the Audit Committee in order for the Audit Committee to establish an hourly rate and other charges EXCO shall pay for the upcoming calendar year for the use of the aircraft. The present hourly rate paid by EXCO to DHM Aviation, LLC is in line with the market rate for similar aircraft.

During 2007, DHM Aviation, LLC purchased a larger used jet aircraft. Based upon a national survey of corporate aircraft charter rates, in August 2007, the Board of Directors approved a rate of $5,700 per flight hour plus $600 per flight hour fuel surcharge for the new aircraft.

During 2007, we reimbursed DHM Aviation, LLC at a rate of $3,600 per hour, including fuel surcharges, for use of the aircraft and $5,700 per flight hour plus $600 per flight hour fuel surcharge for use of the new aircraft. For the 275 day period from January 1, 2005 to October 2, 2005 and the 90 day period from October 3, 2005 to December 31, 2005, we paid DHM Aviation, LLC $0.3 million and $0.1 million, respectively. Payments to DHM Aviation, LLC for the year ended December 31, 2006 and 2007 were $0.4 million and $0.5 million, respectively, for use of the aircraft.

Suite

The Company maintains a suite at the American Airlines Center in Dallas, Texas. During 2006 the Company shared the suite with and was reimbursed for 50% of its expenses relative to the suite by an entity affiliated with Boone Pickens, one of our directors, pursuant to an arrangement entered into in 2006 between the Company and such entity. During the year ended December 31, 2006, the Company paid a total of $350,000 to maintain the suite, of which $175,000 was reimbursed by the entity affiliated with Mr. Pickens. During 2007, this arrangement was terminated and EXCO paid 100% of the costs associated with the American Airlines Center, which totaled $350,000.

Private Placement of Preferred Stock

On March 30, 2007, we completed the Private Placement of an aggregate of $390.0 million of 7.0% Preferred Stock and $1.61 billion of Hybrid Preferred Stock to accredited investors pursuant to the terms and conditions of a Preferred Stock Purchase Agreement dated March 28, 2007. The following related persons participated in the transaction:

- Entities affiliated with Ares Management LLC, or Ares, purchased 2,925 shares of Series C 7.0% Preferred Stock and 12,075 shares of Series A-1 Hybrid Preferred Stock for $150.0 million. Prior to the Private Placement, Ares beneficially owned approximately 6.3% of our outstanding common stock. Jeffrey S. Serota, one of our directors, is a Managing Director of Ares. Mr. Serota was designated to our Board of Directors by Ares pursuant to the terms of the Series C 7.0% Preferred Stock.
- Entities affiliated with Oaktree Capital Management, L.P., or Oaktree, purchased 11,700 shares of Series B 7.0% Preferred Stock and 48,300 shares of Series A-1 Hybrid Preferred Stock for $600.0 million. Prior to the Private Placement, Oaktree beneficially owned approximately 3.1% of our outstanding common stock. Vincent J. Cebula, one of our directors, was a Managing Director of Oaktree until October 31, 2007. Mr. Cebula was originally designated to our Board of Directors by Oaktree pursuant to the terms of the Series B 7.0% Preferred Stock. On October 31, 2007, Mr. Cebula resigned from Oaktree and subsequently joined Jefferies Capital Partners. Since Mr. Cebula resigned from Oaktree, he also resigned as the Series B Preferred Stock director effective December 1, 2007 and was replaced by B. James Ford, a Managing Director of Oaktree. Mr. Cebula remains on our Board of Directors and serves in one of the four board seats reserved for the Preferred Stock. Additionally, Rajath Shourie, a Managing Director of Oaktree, serves in one of the four board seats reserved for the Preferred Stock.
- Entities affiliated with Greenhill Capital Partners, LLC purchased 1,463 shares of Series A-1 7.0% Preferred Stock and 6,037 shares of Series A-1 Hybrid Preferred Stock for $75.0 million. Prior to the Private Placement, Greenhill beneficially owned approximately 2.2% of our outstanding common stock. Robert H. Niehaus, one of our directors, is a Senior Member of GCP 2000, LLC and Managing Director of Greenhill Capital Partners, LLC, which control the general partners of Greenhill Capital Partners, L.P. and its affiliated investment funds.
- Entities affiliated with FMR Corp. purchased 1,952 shares of Series A-1 7.0% Preferred Stock and 8,048 shares of Series A-1 Hybrid Preferred Stock for $100.0 million. Prior to the Private Placement, FMR Corp. beneficially owned approximately 7.0% of our outstanding common stock.

In connection with the Private Placement, we entered into a letter agreement, dated March 28, 2007, with Oaktree pursuant to which we agreed to cause an individual designated by Oaktree to be nominated to serve on our Board of Directors following such time as (i) Oaktree ceases to have the right to elect a director to serve on our Board of Directors pursuant to the Statement of Designation for the Series B 7.0% Preferred Stock and (ii) less than 25% of the shares of 7.0% Preferred Stock and Hybrid Preferred Stock originally issued on March 30, 2007 remain outstanding, and for so long as Oaktree owns at least 10,000,000 shares of our common stock (including, for this purpose, shares of common stock into which any Preferred Stock then held by Oaktree is convertible).

In connection with the Private Placement, we also entered into a letter agreement, dated March 28, 2007, with certain investors affiliated with Ares pursuant to which we agreed to cause an individual designated by Ares to be nominated to serve on our Board of Directors following such time as (i) Ares ceases to have the right to elect a director to serve on our Board of Directors pursuant to the Statement of Designation for the Series C 7.0% Preferred Stock and (ii) less than 25% of the shares of 7.0% Preferred Stock and Hybrid Preferred Stock originally issued on March 30, 2007 remain outstanding, for so long as Ares owns at least 10,000,000 shares of our common stock (including, for this purpose, shares of common stock into which any Preferred Stock then held by Ares is convertible).

For more information about the Private Placement, see "Note 4. Significant Transactions—Private Placement of Preferred Stock".

Gulf Coast Sale

On May 8, 2007, we completed the sale of a portion of the oil and natural gas properties and related assets in multiple fields primarily located in South Texas and South Louisiana acquired in the Southern Gas Acquisition to an entity affiliated with Crimson, for an aggregate sale price of $235.5 million in cash, net of preliminary purchase price adjustments, and 750,000 shares of unregistered restricted Crimson common stock, or the Gulf Coast Sale. The purchase price was negotiated on an arm's-length basis based upon customary industry metrics for acquisitions of oil and natural gas reserves. The purchase agreement for the Gulf Coast Sale contained customary representations, warranties and covenants. Crimson is a publicly-held company that is controlled by investment funds managed by Oaktree. At the time of the Gulf Coast Sale, one of our directors, Vincent J. Cebula was a managing director of Oaktree. Rajath Shourie, a managing director of Oaktree, began serving on our Board of Directors on August 30, 2007. B. James Ford, a managing director of Oaktree and a member of Crimson's board of directors, began serving on our Board of Directors on December 1, 2007.

On August 15, 2007, we entered into an agreement with funds managed by Oaktree to sell our 750,000 shares of Crimson's unregistered restricted common stock for an aggregate sales price of approximately $5.2 million.

Other

Robert Stillwell, Jr., the son of Robert L. Stillwell, one of our directors, was employed by us from October 2002 until July 2005 as a financial analyst. In connection with the Equity Buyout in 2005, Robert Stillwell, Jr. received a payment of $71,187 for certain options granted to him as compensation for his employment with us and a payment of $41,064 under the Employee Stock Participation Plan. These payments were in addition to the prorated annualized salary of $45,000 that Robert Stillwell, Jr. received during the period of his employment in 2005.

Penny Wilson, the spouse of Mark E. Wilson, our Vice President, Chief Accounting Officer and Controller, was retained by us from February 2007 to January 2008 as a consultant, through an independent consulting firm to perform accounting work related to our 2007 acquisitions. In addition to Ms. Wilson's base salary, she also received approximately $19,000 in bonus and commissions from the consulting firm, which were directly tied to her engagement at EXCO. During 2007, fees paid to the consulting firm for Ms. Wilson and other consultants totaled approximately $0.6 million.

16. Concentration of credit risk

For the twelve months ended December 31, 2007, sales to a regulated natural gas utility company, Atmos Energy Marketing L.L.C. and its affiliates, and an independent oil and natural gas company, Anadarko and its affiliates, accounted for 20.0% and 12.1%, respectively, of total oil and natural gas revenues. For the twelve months ended December 31, 2006 and 2005 sales to one industrial customer, Alcan Rolled Products—Ravenswood, LLC, accounted for 4.9% and 10.1%, respectively, of total oil and natural gas revenues. If we were to lose any one of our oil and natural gas purchasers, the loss could temporarily cease or delay production and sale of our oil and natural gas in that particular purchaser's service area. If we were to lose a purchaser, we believe we could identify a substitute purchaser.

17. Geographic operating segment information and oil and natural gas disclosures

We follow SFAS No. 131, "Disclosures About Segments of an Enterprise and Related Information," or SFAS No. 131. We have operations in only one industry segment, that being the oil and natural gas exploration and production industry.

18. Subsequent events

Withdrawal of Master Limited Partnership

On January 10, 2008, we announced the withdrawal of our registration statement related to our proposed master limited partnership. As such, approximately $3.5 to $4.5 million in registration costs, $3.4 of which was deferred in 2007, will be expensed in the first quarter of 2008.

Financial Risk Management Instruments

In January 2008, we entered into financial risk management instruments to mitigate our exposure to fluctuations in interest rates on $700.0 million in principal through February 14, 2010 at LIBOR rates ranging from 2.45% to 2.8%.

Derivative Financial Instruments

Subsequent to December 31, 2007, we entered into additional derivative financial instruments covering 28,021 Mmbtu of natural gas and 731 Bbls of oil at weighted average prices of $8.79 per Mmbtu and $91.18 per Bbl, respectively.

Appalachian acquisition

On February 20, 2008, EXCO acquired shallow natural gas properties from EOG Resources, Inc. located primarily in EXCO's central Pennsylvania operating area. The purchase price was $395.0 million. After reduction for preliminary closing adjustments of $7.4 million, the net purchase price paid on February 20, 2008 was $387.6 and was financed with borrowings under the EXCO Resources Credit Agreement.

EXCO Resources Credit Agreement

In conjunction with the Appalachian acquisition on February 20, 2008, we amended and restated our EXCO Resources Credit Agreement. Our borrowing base was increased from $900 million to $1.2 billion. All other terms remained unchanged. At February 20, 2008, our outstanding balance was $920.5 million.

19. Quarterly financial data (unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2006 and 2007:

(in thousands)	Quarter 1st	2nd	3rd	4th
2006				
Total revenues and other income	$ 112,781	$115,864	$185,329	$145,475
Operating income (loss)	58,428	52,855	116,229	(750)
Net income (loss) available to common shareholders	$ 37,152	$ 31,023	$ 71,745	$ (966)
Basic earnings (loss) per share:				
Net income (loss)	$ 0.46	$ 0.30	$ 0.69	$ (0.01)
Diluted earnings (loss) per share:				
Net income (loss)	$ 0.45	$ 0.29	$ 0.68	$ (0.01)
2007				
Total revenues and other income	$ 28,517	$340,385	$326,229	$211,379
Operating income (loss)	(144,849)	138,107	117,236	(742)
Net income (loss) available to common shareholders	$ (88,833)	$ 31,787	$ 10,729	$(36,995)
Basic earnings (loss) per share:				
Net income (loss)	$ (0.85)	$ 0.30	$ 0.10	$ (0.35)
Diluted earnings (loss) per share:				
Net income (loss)	$ (0.85)	$ 0.30	$ 0.10	$ (0.35)

20. Consolidating financial statements

Set forth below are condensed consolidating financial statements of EXCO, the guarantor subsidiaries and the non-guarantor subsidiaries. The senior notes are jointly and severally guaranteed by some of our subsidiaries in the United States (referred to as Guarantor Subsidiaries). Each of the Guarantor Subsidiaries are wholly-owned subsidiaries of Resources, and the guarantees are unconditional as it relates to the assets of the Guarantor Subsidiaries. In 2007, certain subsidiaries, previously guarantor subsidiaries, were merged into and with Resources.

In connection with the 2007 mergers discussed above, the consolidating balance sheet as of December 31, 2006 and the consolidating statements of operations and consolidating statements of cash flows for the 275 day period from January 1, 2005 to October 2, 2005 and the 90 day period from October 3, 2005 to December 31, 2005 and for the year ended December 31, 2006 have been restated to reflect the guarantor subsidiaries as if they had been part of Resources for all periods presented. We have also presented the 2007 consolidating financial statements to reflect these changes as if it was in place at the beginning of the year.

The following financial information presents consolidating financial statements, which include:

- Resources;
- the guarantor subsidiaries on a combined basis;
- the non-guarantor subsidiaries;
- elimination entries necessary to consolidate Resources, the guarantor subsidiaries and the non-guarantor subsidiaries; and
- EXCO on a consolidated basis.

Investments in subsidiaries are accounted for using the equity method of accounting. The financial information for the guarantor and non-guarantor subsidiaries are presented on a combined basis. The elimination entries primarily eliminate investments in subsidiaries and intercompany balances and transactions.

EXCO Resources, Inc.

Consolidating balance sheet

December 31, 2006

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 6,522	$ 6,233	$ 10,067	$ —	$ 22,822
Other current assets	44,050	36,484	133,354	—	213,888
Total current assets	50,572	42,717	143,421	—	236,710
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties	88,299	19,921	189,699	—	297,919
Proved developed and undeveloped oil and natural gas properties	607,892	818,427	1,066,544	—	2,492,863
Allowance for depreciation, depletion and amortization	(43,863)	(43,260)	(55,468)	—	(142,591)
Oil and natural gas properties, net	652,328	795,088	1,200,775	—	2,648,191
Gas gathering, office and field equipment, net	5,911	33,367	174,883	—	214,161
Deferred financing costs	946	—	14,983		15,929
Oil and natural gas derivatives	4,950	6,440	30,079	—	41,469
Goodwill	110,800	164,469	194,808	—	470,077
Investments in and advances to affiliates	1,167,846	(465,797)	—	(702,049)	—
Advance on probable acquisition	80,000	—	—	—	80,000
Other assets, net	17	471	32	—	520
Total assets	$2,073,370	$ 576,755	$1,758,981	$(702,049)	$3,707,057
Liabilities and shareholders' equity					
Current liabilities	$ 66,859	$ 25,098	$ 98,967	$ —	$ 190,924
Long-term debt	797,832	—	1,283,821	—	2,081,653
Deferred income taxes	11,147	154,989	—	—	166,136
Other liabilities	17,682	60,116	10,696	—	88,494
Payable to parent	—	—	16,385	(16,385)	—
Commitments and contingencies	—	—	—	—	—
Shareholders' equity	1,179,850	336,552	349,112	(685,664)	1,179,850
Total liabilities and shareholders' equity	$2,073,370	$ 576,755	$1,758,981	$(702,049)	$3,707,057

EXCO Resources, Inc.

Consolidating balance sheet

December 31, 2007

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 23,069	$ 7,250	$ 25,191	$ —	$ 55,510
Other current assets	76,261	31,601	147,928	—	255,790
Total current assets	99,330	38,851	173,119	—	311,300
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties	92,680	17,142	224,981	—	334,803
Proved developed and undeveloped oil and natural gas properties	1,192,337	899,745	2,833,971	—	4,926,053
Allowance for depreciation, depletion and amortization	(112,548)	(84,288)	(303,657)	—	(500,493)
Oil and natural gas properties, net	1,172,469	832,599	2,755,295	—	4,760,363
Gas gathering, office and field equipment, net	7,449	32,665	305,294	—	345,408
Advance on pending acquisition	39,500	—	—	—	39,500
Deferred financing costs	7,619	—	12,787		20,406
Oil and natural gas derivatives	851	—	1,640	—	2,491
Goodwill	110,800	164,469	194,808	—	470,077
Investments in and advances to affiliates	2,525,487	—	—	(2,525,487)	—
Other assets, net	—	668	5,558	—	6,226
Total assets	$3,963,505	$1,069,252	$3,448,501	$(2,525,487)	$5,955,771
Liabilities and shareholders' equity					
Current liabilities	$ 118,522	$ 35,959	$ 123,686	$ —	$ 278,167
Long-term debt	1,016,171	—	1,083,000	—	2,099,171
Deferred income taxes	105,531	165,867	—	—	271,398
Other liabilities	77,189	67,197	54,629	—	199,015
Payable to parent	(461,928)	468,607	(6,679)	—	—
Commitments and contingencies	—	—	—	—	—
Preferred stock	1,992,278	—	—	—	1,992,278
Shareholders' equity	1,115,742	331,622	2,193,865	(2,525,487)	1,115,742
Total liabilities and shareholders' equity	$3,963,505	$1,069,252	$3,448,501	$(2,525,487)	$5,955,771

EXCO Resources, Inc.

Consolidating statement of operations

For the 275 day period ended October 2, 2005

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas sales	$ 41,222	$ 77,644	$13,955	$ —	$132,821
Derivative financial instruments	(56,706)	(120,547)	—	—	(177,253)
Other income (loss)	32,012	1,269	141	(26,326)	7,096
Equity in earnings of subsidiaries	(59,838)	—	—	59,838	—
Total revenues	(43,310)	(41,634)	14,096	33,512	(37,336)
Costs and expenses:					
Oil and natural gas production	9,010	10,750	2,397	—	22,157
Depreciation, depletion and amortization	5,888	13,332	5,467	—	24,687
Accretion of discount on asset retirement obligations	263	340	14	—	617
General and administrative	76,680	10,124	2,638	—	89,442
Interest	26,675	26,326	—	(26,326)	26,675
Total costs and expenses	118,516	60,872	10,516	(26,326)	163,578
Income (loss) before income taxes	(161,826)	(102,506)	3,580	59,838	(200,914)
Income tax benefit	(21,538)	(42,160)	—	—	(63,698)
Income (loss) before discontinued operations	(140,288)	(60,346)	3,580	59,838	(137,216)
Discontinued operations:					
Loss from operations	—	—	(4,403)	—	(4,403)
Gain on disposition of Addison Energy Inc.	175,717	—	—	—	175,717
Income tax (benefit) expense	50,613	—	(1,331)	—	49,282
Income (loss) from discontinued operations	125,104	—	(3,072)	—	122,032
Net income (loss)	$ (15,184)	$ (60,346)	$ 508	$ 59,838	$(15,184)

EXCO Resources, Inc.

Consolidating statement of operations

For the 90 day period ended December 31, 2005

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas sales	$14,885	$46,790	$ 8,386	$ —	$70,061
Derivative financial instruments	2,856	(3,112)	—	—	(256)
Other income (loss)	7,821	516	112	(6,075)	2,374
Equity earnings of subsidiaries	17,444	—	—	(16,607)	837
Total revenues	43,006	44,194	8,498	(22,682)	73,016
Costs and expenses:					
Oil and natural gas production	3,312	4,380	1,257	—	8,949
Depreciation, depletion and amortization	3,110	8,382	2,579	—	14,071
Accretion of discount on asset retirement obligations	75	142	9	—	226
General and administrative	3,942	1,387	1,046	—	6,375
Interest	19,414	6,075	—	(6,075)	19,414
Total costs and expenses	29,853	20,366	4,891	(6,075)	49,035
Income (loss) before income taxes	13,153	23,828	3,607	(16,607)	23,981
Income tax expense (benefit)	(3,197)	10,828	—	—	7,631
Net income (loss)	$16,350	$13,000	$ 3,607	$(16,607)	$16,350

EXCO Resources, Inc.

Consolidating statement of operations

For the year ended December 31, 2006

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas sales	$174,507	$121,787	$59,486	$ —	$355,780
Commodity price risk management activities	84,349	88,768	25,547	—	198,664
Other income (loss)	30,909	1,755	948	(28,607)	5,005
Equity in earnings of subsidiaries	73,153	—	—	(71,560)	1,593
Total revenues	362,918	212,310	85,981	(100,167)	561,042
Costs and expenses:					
Oil and natural gas production	33,391	20,590	14,893	—	68,874
Depreciation, depletion and amortization	67,122	38,241	30,359	—	135,722
Accretion of discount on asset retirement obligations	854	941	219	—	2,014
General and administrative	25,176	11,121	4,909	—	41,206
Interest	53,246	28,607	31,625	(28,607)	84,871
Total costs and expenses	179,789	99,500	82,005	(28,607)	332,687
Income before income taxes	183,129	112,810	3,976	(71,560)	228,355
Income tax expense	44,175	45,226	—	—	89,401
Income (loss) from operations	$138,954	$ 67,584	$ 3,976	$ (71,560)	$138,954

EXCO Resources, Inc.

Consolidating statement of operations

For the year ended December 31, 2007

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Revenues and other income:					
Oil and natural gas sales	$ 224,238	$121,994	$499,828	$ —	$ 846,060
Derivative financial instruments	(25,788)	(8,612)	61,207	—	26,807
Other income (loss)	35,572	(27,177)	25,248	—	33,643
Equity in earnings of subsidiaries	89,823	—	—	(89,823)	—
Total revenues and other income	323,845	86,205	586,283	(89,823)	906,510
Costs and expenses:					
Oil and natural gas production	50,755	26,279	93,406	—	170,440
Depreciation, depletion and amortization	70,767	44,427	260,226	—	375,420
Accretion of discount on asset retirement obligations	1,512	1,946	1,420	—	4,878
General and administrative	36,040	10,962	17,668	—	64,670
Interest	62,540	—	118,810	—	181,350
Total costs and expenses	221,614	83,614	491,530	—	796,758
Income before income taxes	102,231	2,591	94,753	(89,823)	109,752
Income tax expense	52,575	7,521	—	—	60,096
Net income (loss)	49,656	(4,930)	94,753	(89,823)	49,656
Preferred stock dividends	(132,968)	—	—	—	(132,968)
Net income (loss) available to common shareholders	$ (83,312)	$ (4,930)	$ 94,753	$(89,823)	$ (83,312)

EXCO Resources, Inc.

Consolidating statement of cash flow

For the 275 day period ended October 2, 2005

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash used in operating activities	$ (55,614)	$ (13,621)	$(11,887)	$ —	$ (81,122)
Investing Activities:					
Additions to oil and natural gas properties, gathering systems and equipment	(6,601)	(101,835)	(42,708)	—	(151,144)
Proceeds from dispositions of oil and natural gas properties	45,375	635	—	—	46,010
Proceeds from sale of Addison	444,812	—	(1,415)		443,397
Advances/investments with affiliates	(114,314)	127,864	(13,550)	—	—
Proceeds from sales of marketable securities	59	—	—	—	59
Net cash used in investing activities of discontinued operations	—	—	(442)	—	(442)
Net cash provided by (used in) investing activities	369,331	26,664	(58,115)	—	337,880
Financing Activities:					
Proceeds from long-term debt	41,300	—	—	—	41,300
Payments on long-term debt	(148,247)	—	—	—	(148,247)
Principal and interest on notes receivable-employees	311			—	311
Net cash used in financing of discontinued operations	—	—	59,601	—	59,601
Net cash provided by (used in) financing activities	(106,636)	—	59,601	—	(47,035)
Net increase (decrease) in cash	207,081	13,043	(10,401)	—	209,723
Cash at the beginning of the period	8,535	7,472	10,401	—	26,408
Cash at end of period	$ 215,616	$ 20,515	$ —	$ —	$ 236,131

EXCO Resources, Inc.

Consolidating statement of cash flow

For the 90 day period ended December 31, 2005

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by (used in) operating activities	$(13,402)	$15,360	$ 6,219	$ —	$ 8,177
Investing Activities:					
Investment in TXOK Acquisition, Inc.	(20,000)	—	—	—	(20,000)
Additions to oil and natural gas properties, gathering systems and equipment	126	(6,880)	(6,453)	—	(13,207)
Proceeds from dispositions of oil and natural gas properties	(395)	2	—	—	(393)
Advances/investments in affiliates	13,544	6,456	—	—	20,000
Advances from related parties	—	—	—	—	—
Other investing activities	29	—	234	—	263
Net cash provided by (used in) investing activities	(6,696)	(422)	(6,219)	—	(13,337)
Financing Activities:					
Proceeds from long-term debt	9,999	—	—	—	9,999
Payments on long-term debt	(15,279)	—	—	—	(15,279)
Principal and interest on notes receivable—employees	1,262	—	—	—	1,262
Net cash used in financing activities	(4,018)	—	—	—	(4,018)
Net increase (decrease) in cash	(24,116)	14,938	—	—	(9,178)
Cash at the beginning of the period	215,616	20,515	—	—	236,131
Cash at end of period	$191,500	$35,453	$ —	$ —	$226,953

EXCO Resources, Inc.

Consolidating statement of cash flow

For the year ended December 31, 2006

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by operating activities	$ 94,535	$ 74,773	$ 58,351	$ —	$ 227,659
Investing Activities:					
Additions to oil and natural gas properties, gathering systems and equipment	(146,077)	(111,370)	(176,719)	—	(434,166)
Proceeds from dispositions of oil and natural gas properties	4,556	150	1,118	—	5,824
Cash acquired in acquisition of TXOK Acquisition, Inc.	32,259	—	—	—	32,259
Advance to TXOK Acquisition, Inc. for preferred stock redemption	(158,750)	—	—	—	(158,750)
Acquisition of Power Gas Marketing & Transmission, Inc., net of cash acquired	—	(61,774)	—	—	(61,774)
Acquisition of Winchester Energy Company, Ltd., net of cash acquired	—	—	(1,094,910)	—	(1,094,910)
Advances/investments with affiliates	(44,635)	120,197	(75,562)	—	—
Advance payment on probable acquisition	(80,000)	—	—	—	(80,000)
Net cash used in investing activities	(392,647)	(52,797)	(1,346,073)	—	(1,791,517)
Financing Activities:					
Proceeds from long-term debt	583,000	—	1,301,250	—	1,884,250
Payments on long-term debt	(1,102,751)	(13,098)	(11,000)	—	(1,126,849)
Payments of hedges in conjunction with Power Gas Marketing & Transmission, Inc. acquisition	—	(38,098)	—	—	(38,098)
Cash settlements of assumed derivative financial instruments	—	—	—		—
Proceeds from issuance of common stock, net	657,381	—	—	—	657,381
Deferred financing costs and other	(1,117)	—	(15,840)	—	(16,957)
Net cash provided by (used in) financing activities	136,513	(51,196)	1,274,410	—	1,359,727
Net decrease in cash	(161,599)	(29,220)	(13,312)	—	(204,131)
Cash at the beginning of the period	168,121	35,453	23,379	—	226,953
Cash at end of period	$ 6,522	$ 6,233	$ 10,067	$ —	$ 22,822

EXCO Resources, Inc.

Consolidating statement of cash flow

For the year ended December 31, 2007

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by operating activities	$ 141,403	$ 69,223	$ 367,203	$ —	$ 577,829
Investing Activities:					
Additions to oil and natural gas properties, gathering systems and equipment	(999,434)	(68,154)	(1,779,381)	—	(2,846,969)
Proceeds from dispositions of property and equipment	485,714	354	4,294	—	490,362
Advance payment on probable acquisition	(39,500)	—	—	—	(39,500)
Sale of Crimson stock	5,228	—	—	—	5,228
Other	—	—	(5,558)	—	(5,558)
Advances/investments with affiliates	(1,648,245)	(406)	1,648,651	—	—
Net cash used in investing activities	(2,196,237)	(68,206)	(131,994)	—	(2,396,437)
Financing Activities:					
Proceeds from long-term debt	972,500	—	1,263,000	—	2,235,500
Payments on long-term debt	(751,000)	—	(1,470,532)	—	(2,221,532)
Settlement of derivative financial instruments with a financing element	(11,578)	—	(2,636)	—	(14,214)
Proceeds from issuance of common stock, net	4,162	—	—	—	4,162
Proceeds from issuance of preferred stock, net	1,992,273	—	—	—	1,992,273
Payment of preferred stock dividend	(127,134)	—	—	—	(127,134)
Deferred financing costs and other	(7,850)	—	(9,909)	—	(17,759)
Net cash provided by (used in) financing activities	2,071,373	—	(220,077)	—	1,851,296
Net increase in cash	16,539	1,017	15,132	—	32,688
Cash at the beginning of the period	6,522	6,233	10,067	—	22,822
Cash at end of period	$ 23,061	$ 7,250	$ 25,199	$ —	$ 55,510

21. Supplemental information relating to oil and natural gas producing activities— continuing operations (unaudited)

Presented below are costs incurred in oil and natural gas property acquisition, exploration and development activities (excluding all amounts related to our former Canadian subsidiary):

(in thousands, except per unit amounts)	Amount
For the 275 day period from January 1, 2005 to October 2, 2005:	
Proved property acquisition costs	$ 103,222
Development and exploration costs(1)	39,900
Capitalized asset retirement costs	1,686
Depreciation, depletion and amortization per Boe	$ 8.35
Depreciation, depletion and amortization per Mcfe	$ 1.39
For the 90 day period from October 3, 2005 to December 31, 2005:	
Development and exploration costs(1)	$ 13,194
Capitalized asset retirement costs	51
Depreciation, depletion and amortization per Boe	$ 14.54
Depreciation, depletion and amortization per Mcfe	$ 2.42
2006:	
Proved property acquisition costs(2)	$1,384,056
Unproved property acquisition costs(3)	248,330
Total property acquisition costs	1,632,386
Development and exploration costs(1)	194,312
Lease acquisitions and other	8,991
Capitalized asset retirement costs	21,681
Depreciation, depletion and amortization per Boe	$ 16.44
Depreciation, depletion and amortization per Mcfe	$ 2.74
2007:	
Proved property acquisition costs(4)	$2,356,354
Unproved property acquisition costs(5)	117,893
Total property acquisition costs	2,474,247
Development and exploration costs(1)	446,675
Lease acquisitions and other	21,415
Capitalized asset retirement costs	5,127
Depreciation, depletion and amortization per Boe	$ 18.57
Depreciation, depletion and amortization per Mcfe	$ 3.10

(1) Exploration costs are not considered material.

(2) Includes $489.1 million, $123.0 million and $583.7 million allocated to proved oil and natural gas properties in connection with the TXOK, PGMT and Winchester acquisitions, respectively.

(3) Includes $60.8 million, $0.4 million and $154.3 million allocated to unproved oil and natural gas properties in connection with the TXOK, PGMT and Winchester acquisitions and $32.8 million of other purchase accounting acquisitions to unproved property acquisition costs, respectively.

(4) Includes $1,417.8 million and $577.9 million allocated to proved oil and natural gas properties in connection with the Vernon and Southern Gas acquisitions, respectively. In addition, $201.2 million of proved property acquisitions have been included to reflect the purchase of the Southern Gas properties on May 2, 2007 which were sold to Crimson on May 8, 2007.

(5) Includes $58.2 million and $4.7 million allocated to unproved oil and natural gas properties in connection with the Vernon and Southern Gas acquisitions, respectively. In addition, $34.3 million of unproved property acquisitions resulting from the purchase of Southern Gas properties on May 2, 2007 which were sold to Crimson on May 8, 2007.

We retain independent engineering firms to provide annual year-end estimates of our future net recoverable oil and natural gas reserves. The estimated proved net recoverable reserves we show below include only those quantities that we expect to be commercially recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods. Proved Developed Reserves represent only those reserves that we may recover through existing wells. Proved Undeveloped Reserves include those reserves that we may recover from new wells on undrilled acreage or from existing wells on which we must make a relatively major expenditure for recompletion or secondary recovery operations. All of our reserves are located onshore in the continental United States of America.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of our oil and natural gas properties. Estimates of fair value should also consider unproved reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is subjective and imprecise. All amounts related to our former Canadian subsidiary, have been excluded from the information contained in this note.

Estimated Quantities of Proved Reserves

(in thousands)	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)(1)	Mcfe(2)
December 31, 2004	7,236	361,392	210	406,068
Purchase of reserves in place	60	59,780	—	60,140
New discoveries and extensions	349	30,834	—	32,928
Revisions of previous estimates	11	(12,608)	(190)	(13,682)
Production	(491)	(20,482)	(20)	(23,548)
Sales of reserves in place	(343)	(17,886)	—	(19,944)
December 31, 2005	6,822	401,030	—	441,962
Purchase of reserves in place	8,775	723,427	—	776,077
New discoveries and extensions	2,018	80,832	—	92,940
Revisions of previous estimates	(487)	(33,467)	—	(36,389)
Production	(916)	(44,123)	—	(49,619)
Sales of reserves in place	(57)	(1,097)	—	(1,439)
December 31, 2006	16,155	1,126,602	—	1,223,532
Purchase of reserves in place	10,500	770,567	—	833,567
New discoveries and extensions(3)	2,469	178,248	—	193,062
Revisions of previous estimates(4)	(188)	(78,647)	—	(79,775)
Production	(1,645)	(111,419)	—	(121,289)
Sales of reserves in place	(6,361)	(145,801)	—	(183,967)
December 31, 2007	20,930	1,739,550	—	1,865,130

Estimated Quantities of Proved Developed Reserves

(in thousands)	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)(1)	Mcfe(2)
December 31, 2005	5,527	321,716	—	354,878
December 31, 2006	11,290	665,263	—	733,003
December 31, 2007	15,180	1,228,736	—	1,319,816

(1) Beginning December 31, 2005, NGL's are no longer tracked separately as they are considered immaterial.

(2) Mcfe-One thousand cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

(3) New discoveries and extensions between December 31, 2006 and December 31, 2007 include 114,980 Mmcfe in East Texas/North Louisiana, 43,271 Mmcfe in Appalachia, 28,608 Mmcfe in Permian and 6,203 Mmcfe in our other areas.

(4) Revisions between December 31, 2006 and December 31, 2007 include a positive revision of 59,550 Mcfe due to price changes and negative revisions totaling 139,325 Mcfe due primarily to performance issues in Appalachia and East Texas/North Louisiana and cost increases, particularly in Appalachia.

Standardized measure of discounted future net cash flows

We have summarized the Standardized Measure related to our proved oil, natural gas, and NGL reserves. We have based the following summary on a valuation of Proved Reserves using discounted cash flows based on year-end prices, costs and economic conditions and a 10% discount rate. The additions to Proved Reserves from the purchase of reserves in place, and new discoveries and extensions could vary significantly from year to year; additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant. Accordingly, you should not view the information presented below as an estimate of the fair value of our oil and natural gas properties, nor should you consider the information indicative of any trends.

Standardized Measure of Discounted Future Net Cash Flows

(in thousands)	Amount
Year ended December 31, 2005:	
Future cash inflows	$ 4,334,629
Future production, development and abandonment costs	1,148,283
Future income taxes	1,097,606
Future net cash flows	2,088,740
Discount of future net cash flows at 10% per annum.	1,265,441
Standardized measure of discounted future net cash flows(1)	$ 823,299
Year ended December 31, 2006:	
Future cash inflows	$ 7,173,640
Future production, development and abandonment costs	3,397,690
Future income taxes	721,154
Future net cash flows	3,054,796
Discount of future net cash flows at 10% per annum	1,743,021
Standardized measure of discounted future net cash flows	$ 1,311,775
Year ended December 31, 2007:	
Future cash inflows	$13,562,925
Future production, development and abandonment costs	5,115,858
Future income taxes	1,857,530
Future net cash flows	6,589,537
Discount of future net cash flows at 10% per annum	3,470,650
Standardized measure of discounted future net cash flows	$ 3,118,887

During recent years, prices paid for oil and natural gas have fluctuated significantly. The spot prices at December 31, 2005, 2006 and 2007 used in the above table, were $61.03, $60.82 and $95.92 per Bbl of oil, respectively, and $10.08, $5.64 and $6.80 per Mmbtu of natural gas, respectively, in each case adjusted for historical differentials.

The following are the principal sources of change in the Standardized Measure:

(in thousands)	
Year ended December 31, 2005:	
Sales and transfers of oil and natural gas produced, net of production costs	$ (171,775)
Net changes in prices and production costs	511,666
Extensions and discoveries, net of future development and production costs	87,239
Development costs during the period	53,094
Changes in estimated future development costs	(58,997)
Revisions of previous quantity estimates	(21,895)
Sales of reserves in place	(29,363)
Purchase of reserves in place	117,572
Accretion of discount before income taxes	69,849
Changes in timing, foreign currency translation and other	(7,344)
Net change in income taxes	(200,484)
Net change	$ 349,562
Year ended December 31, 2006:	
Sales and transfers of oil and natural gas produced, net of production costs	$ (286,906)
Net changes in prices and production costs	(541,139)
Extensions and discoveries, net of future development and production costs	96,494
Development costs during the period	194,312
Changes in estimated future development costs	(140,061)
Revisions of previous quantity estimates	(108,658)
Sales of reserves in place	(4,298)
Purchase of reserves in place	991,548
Accretion of discount before income taxes	124,395
Changes in timing, foreign currency translation and other	23,900
Net change in income taxes	138,889
Net change	$ 488,476
Year ended December 31, 2007:	
Sales and transfers of oil and natural gas produced, net of production costs	$ (679,211)
Net changes in prices and production costs	513,856
Extensions and discoveries, net of future development and production costs	461,961
Development costs during the period	446,675
Changes in estimated future development costs	(125,395)
Revisions of previous quantity estimates	(175,857)
Sales of reserves in place	(298,328)
Purchase of reserves in place	1,923,731
Accretion of discount before income taxes	156,736
Changes in timing and other	126,192
Net change in income taxes	(543,248)
Net change	$1,807,112

Supplemental information relating to oil and natural gas producing activities—discontinued operations (unaudited)

Presented below are costs incurred in oil and natural gas property acquisition, exploration and development activities of our discontinued operations, which relate to our former Canadian subsidiary.

(in thousands, except per unit amounts)	
For the 275 day period from January 1, 2005 to October 2, 2005:	
Property acquisition costs	$ 16
Development costs	272
Capitalized asset retirement costs	—
Depreciation, depletion and amortization per Boe	$7.49
Depreciation, depletion and amortization per Mcfe	$1.16

We used our internal engineers for 2004 to provide annual year-end estimates of our future net recoverable oil, natural gas and NGL reserves. The estimated proved net recoverable reserves we show below include only those quantities that we expect to be commercially recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods. Proved Developed Reserves represent only those reserves that we may recover through existing wells. Proved Undeveloped Reserves include those reserves that we may recover from new wells on undrilled acreage or from existing wells on which we must make a relatively major expenditure for recompletion or secondary recovery operations.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of our oil and natural gas properties. Estimates of fair value should also consider unproved reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is subjective and imprecise.

Estimated Quantities of Proved Reserves

(in thousands)	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Mcfe(1)
December 31, 2004	9,339	167,172	9,502	280,218
Purchase of reserves in place	—	—	—	—
New discoveries and extensions	—	—	—	—
Revisions of previous estimates	—	—	—	—
Production	(64)	(1,142)	(84)	(2,030)
Sales of reserves in place	(9,275)	(166,030)	(9,418)	(278,188)
December 31, 2005	—	—	—	—

(1) Mcfe-One thousand cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Standardized measure of discounted future net cash flows—discontinued operations

We have summarized the Standardized Measure related to our former Canadian subsidiary's proved oil, natural gas, and NGL reserves. We have based the following summary on a valuation of Proved Reserves using discounted cash flows based on year-end prices, costs and economic conditions and a 10% discount rate. The additions to Proved Reserves from the purchase of reserves in place, and new discoveries and extensions could vary significantly from year to year; additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant.

Accordingly, you should not view the information presented below as an estimate of the fair value of our oil and natural gas properties, nor should you consider the information indicative of any trends.

Changes in standardized measure—discontinued operations

The following are the principal sources of change in the Standardized Measure:

(in thousands)	
Year ended December 31, 2005:	
Sales and transfers of oil and natural gas produced, net of production costs	$ (8,756)
Development costs during the period	272
Accretion of discount before income taxes	2,999
Changes in timing, foreign currency translation and other	(11,002)
Sales of reserves in place	(343,349)
Net change	$(359,836)

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures. EXCO's management, with the participation of EXCO's principal executive officer and principal financial officer, evaluated the effectiveness of EXCO's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended, or Exchange Act) as of the end of the period covered by this report. Based on this evaluation, the principal executive officer and principal financial officer have concluded that EXCO's disclosure controls and procedures were effective as of the Evaluation Date to ensure that information that is required to be disclosed by EXCO in the reports it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms and (ii) accumulated and communicated to EXCO's management as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting. EXCO's management is responsible for establishing and maintaining effective internal control over financial reporting (as defined in Rule 13a-15(f) or 15d-15(f) promulgated under the Exchange Act). Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of an internal control system in future periods can change with conditions.

EXCO's management assessed the effectiveness of EXCO's internal control over financial reporting as of December 31, 2007. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO, in *Internal Control—Integrated Framework.* Based on this assessment, management believes that, as of December 31, 2007, EXCO's internal control over financial reporting is effective based on those criteria.

There were no changes in EXCO's internal control over financial reporting that occurred during the fiscal quarter ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect, EXCO's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this Item 11 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required in response to this Item 12 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required in response to this Item 13 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required in response to this Item 14 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) See Part II—Item 8. Financial Statements and Supplementary Data in this Annual Report on Form 10-K.

(a)(2) None.

(a)(3) See "Index to Exhibits" for a description of our exhibits.

(b) See "Index to Exhibits" for a description of our exhibits.

(c) None.

SIGNATURE PAGE

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.

Date: February 28, 2008	**EXCO RESOURCES, INC.** **(Registrant)**
	By: /s/ DOUGLAS H. MILLER Douglas H. Miller Chairman and Chief Executive Officer

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 and on the date indicated.

Date: February 28, 2008	/s/ DOUGLAS H. MILLER Douglas H. Miller Director, Chairman and Chief Executive Officer
	/s/ STEPHEN F. SMITH Stephen F. Smith Director, Vice Chairman and President
	/s/ J. DOUGLAS RAMSEY J. Douglas Ramsey Vice President, Chief Financial Officer and Treasurer
	/s/ MARK E. WILSON Mark E. Wilson Vice President, Chief Accounting Officer and Controller
	/s/ JEFFREY D. BENJAMIN Jeffrey D. Benjamin Director
	/s/ VINCENT J. CEBULA Vincent J. Cebula Director

/s/ B. JAMES FORD

B. James Ford
Director

/s/ ROBERT H. NIEHAUS

Robert H. Niehaus
Director

/s/ BOONE PICKENS

Boone Pickens
Director

/s/ JEFFREY S. SEROTA

Jeffrey S. Serota
Director

/s/ RAJATH SHOURIE

Rajath Shourie
Director

/s/ ROBERT L. STILLWELL

Robert L. Stillwell
Director

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(d) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

Not applicable.

DIRECTORS

Douglas H. Miller
Chairman of the Board and
Chief Executive Officer
EXCO Resources, Inc.

Stephen F. Smith
Vice Chairman of the Board
and President
EXCO Resources, Inc.

Jeffrey D. Benjamin [1,2,3]
Senior Advisor
Apollo Management, LP

Vincent J. Cebula [2,3]
Managing Director
Jeffries Capital Partners

Earl E. Ellis [1,2]
Chairman and Chief Executive Officer
Whole Harvest Products

B. James Ford [2]
Managing Director
Oaktree Capital Management, L.P.

Robert H. Niehaus [1,2]
Chairman and Founder
Greenhill Capital Partners, LLC

Boone Pickens
Chairman and Chief Executive Officer
BP Capital LP

Jeffrey S. Serota [2,3]
Senior Partner
Ares Management, LLC

Rajath Shouri [3]
Managing Director
Oaktree Capital Management, L.P.

Robert L. Stillwell [2,3]
General Counsel
BP Capital LP

OFFICERS

Douglas H. Miller
Chairman of the Board and Chief
Executive Officer

Stephen F. Smith
Vice Chairman of the Board and
President

J. Douglas Ramsey, Ph.D.
Vice President, Chief Financial Officer
and Treasurer

Harold L. Hickey
Vice President and Chief Operating
Officer

William L. "Lanny" Boeing
Vice President, Secretary and General
Counsel

Richard L. Hodges
Vice President of Land and
Assistant Secretary

Mark E. Wilson
Vice President, Controller and Chief
Accounting Officer

Michael R. Chambers, Sr.
Vice President of Operations and
General Manager-East Texas/North
Louisiana Division

W. Justin Clarke
Assistant General Counsel, Chief
Compliance Officer
and Assistant Secretary

Charles R. Evans
Vice President and General Manager-
Midcontinent Division

Joe D. Ford
Vice President of Human Resources

OFFICERS (continued)

John D. Jacobi
Vice President of Business
Development and Marketing

Tommy Knowles
Vice President and General Manager-
Permian/Rockies Division

Stephen E. Puckett
Vice President of
Reservoir Engineering

Paul B. Rudnicki
Vice President of Financial Planning
and Analysis

Marcia Simpson
Vice President of Engineering

Wendy L. Straatmann
Vice President and General Manager-
Appalachia Division

[1]Audit Committee Member [2]Compensation Committee Member
[3]Nominating and Corporate Governance Committee Member

SEC and NYSE Certifications

The Form 10-K, included herein, which was filed by the company with the Securities and Exchange Commission (SEC) for the fiscal year ending December 31, 2007, includes, as exhibits, the certifications of our chief executive officer, chief financial officer and chief accounting officer required to be filed with the SEC. Our chief executive officer also filed his 2007 annual CEO certification with the NYSE confirming that the company has complied with the NYSE corporate governance listing standards.

SHAREHOLDER INFORMATION

Shareholder Relations

Donna Sablotny
214-706-3310

NYSE Symbol

XCO – Common Stock

Auditors

KPMG LLP
717 North Harwood Street,
Suite 3100
Dallas, TX 75201

Legal Counsel

Haynes and Boone, LLP
901 Main Street, Suite 3100
Dallas, TX 75202

Vinson & Elkins LLP
Trammell Crow Center
2001 Ross Avenue, Suite 3700
Dallas, TX 75201

Number of Common Shareholders

7,927
(As of March 26, 2008)

Stock Transfer Agent

Continental Stock Transfer
& Trust Company
Communications concerning transfer or exchange requirements, lost certificates, shareholdings or changes of address should be directed to:
17 Battery Place, 8th Floor
New York, New York 10004
212-509-4000

EXCO Resources, Inc.
12377 Merit Drive, Suite 1700
Dallas, TX 75251
www.excoresources.com

END