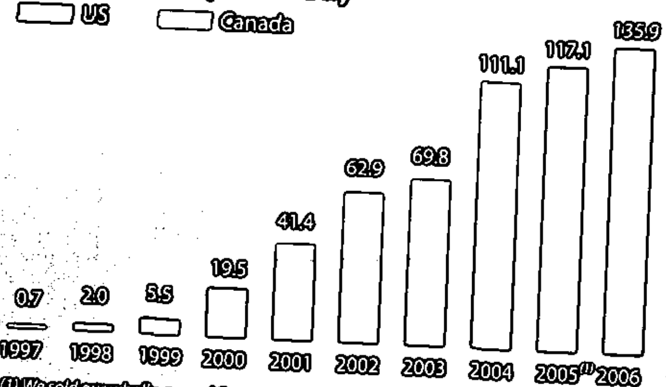
2006 ANNUAL REPORT

OUR BIG PICTURE

JUST GOT BIGGER

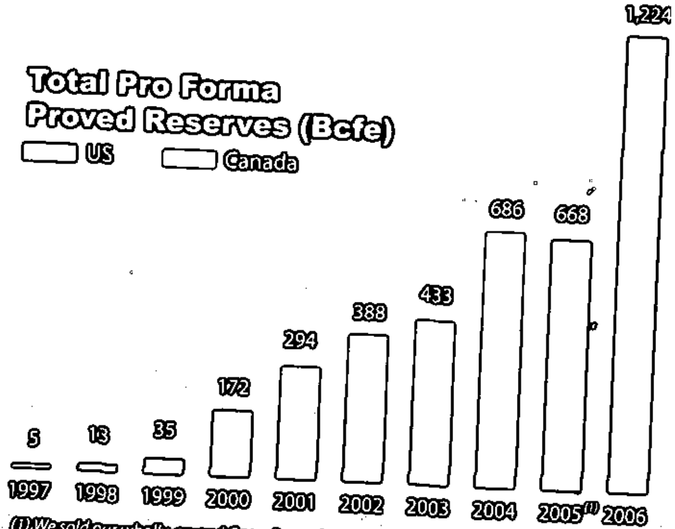
EXCO Resources, Inc.

Daily Pro Forma Production (Mmcfed)



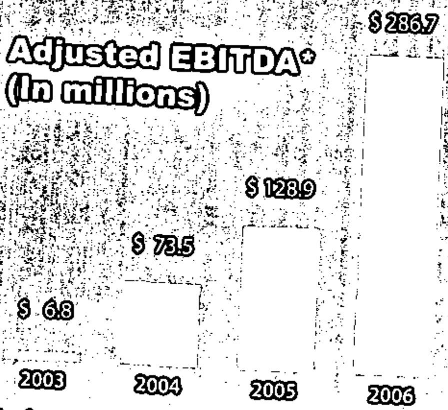
(1) We sold our wholly-owned Canadian subsidiary, Addison Energy Inc. in February 2005. Daily production in 2005 is pro forma for the acquisition of TXOK Acquisition, Inc., which was acquired by EXCO in February 2006.

Total Pro Forma Proved Reserves (Bcfe)



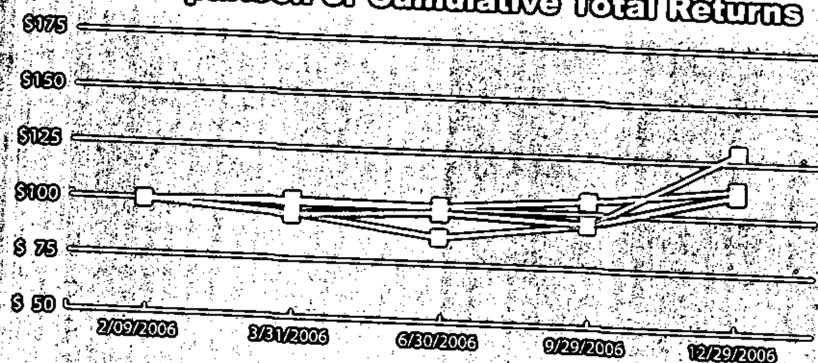
(1) We sold our wholly-owned Canadian subsidiary, Addison Energy Inc. in February 2005. Total proved reserves in 2005 are pro forma for the acquisition of TXOK Acquisition, Inc., which was acquired by EXCO in February 2006.

Adjusted EBITDA* (In millions)



*See footnote 2 of the accompanying Financial Highlights.

Comparison of Cumulative Total Returns



	Quarter Ended				
	2/09/2006	3/31/2006	6/30/2006	9/29/2006	12/29/2006
EXCO Resources, Inc.	$ 100.00	$ 96.02	$ 87.36	$ 95.10	$ 129.58
Crude Petroleum & Natural Gas	$ 100.00	$ 95.58	$ 98.51	$ 95.64	$ 110.79
NYSE Market Index	$ 100.00	$ 101.79	$ 101.20	$ 105.66	$ 113.27

The graph above 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.

EXCO RESOURCES, INC. is an independent energy company engaged in the acquisition, development and exploitation of onshore North American oil and natural gas properties. Our principal operations are focused in key oil and natural gas regions including East Texas/North Louisiana, Appalachia, the Mid-Continent 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 and reduction of costs.

Financial Highlights

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

Results of Operations	Non-GAAP combined 2003 [1]	2004	Non-GAAP combined 2005 [1]	2006	2005-2006 Change
	Years ended December 31,				
Oil and natural gas revenues					
(before effects of derivative financial instruments)	$ 44.2	$ 142.0	$ 202.9	$ 355.8	75%
Adjusted EBITDA [2]	$ 6.8	$ 73.5	$ 128.9	$ 286.7	122%
Net income	$ 5.1	$ 6.0	$ 1.2	$ 139.0	11,483%
Cash flow provided by (used in) operating activities [3]	$ 41.9	$ 118.8	$ (72.9)	$ 227.7	412%
Total production (Bcfe) [4]	12.4	23.0	23.5	49.6	111%
Productive wells drilled (gross)	12	97	108	367	240%
Drilling success rate	80%	97%	97%	98%	1%
Total acreage (gross)	0.8	0.7	1.0	1.5	50%
Total productive wells (gross)	5,044	4,663	6,468	8,964	39%

Financial Position	2003	2004	2005	2006	2005-2006 Change
	Years ended December 31,				
Total assets	$ 505.0	$ 922.0	$ 1,530.5	$ 3,707.1	142%
Long-term debt, less current maturities	$ 99.5	$ 487.5	$ 461.8	$ 2,081.7	351%
Shareholders' equity	$ 183.9	$ 203.8	$ 370.9	$ 1,179.9	218%
Total proved reserves (Bcfe) [4,5]	224	406	442	1,224	177%
Pre-tax present value, discounted at 10% [6]	$ 331.9	$ 700.4	$ 1,248.6	$ 1,606.0	29%
Year-end NYMEX prices:					
Oil (per Bbl)	$ 32.52	$ 43.33	$ 61.03	$ 60.82	(0)%
Natural gas (Mmbtu)	$ 6.19	$ 6.18	$ 10.08	$ 5.64	(44)%

Footnotes to Financial Highlights

Table to Accompany Footnote 1 (In millions)	Public predecessor: For the 209 day period from January 1, 2003 to July 28, 2003	Private predecessor: For the 156 day period from July 29, 2003 to December 31, 2003	Non-GAAP combined 2003	Private predecessor: Year ended December 31, 2004	Private 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	**Year ended December 31, 2006**
Oil and natural gas revenues (before commodity price risk management activities)	$ 22.4	$ 21.8	$ 44.2	$ 142.0	$ 132.8	$ 70.1	$ 202.9	**$ 355.8**
Adjusted EBITDA (2)	$ 1.9	$ 4.9	$ 6.8	$ 73.5	$ 91.8	$ 37.1	$ 128.9	**$ 286.7**
Net income	$ 1.0	$ 4.1	$ 5.1	$ 6.0	$ (15.2)	$ 16.4	$ 1.2	**$ 139.0**
Cash flow provided by (used in) operating activities (3)	$ 20.4	$ 21.5	$ 41.9	$ 118.8	$ (81.2)	$ 8.3	$ (72.9)	**$ 227.7**
Total production (Bcfe) (4)	7.4	5.0	12.4	23.0	17.7	5.8	23.5	**49.6**

(1) The 2003 non-GAAP results represent the combined total of the 209 day public predecessor period ended July 28, 2003 and the 156 day private predecessor period ended December 31, 2003. The 2005 non-GAAP results represent the combined total of the 275 day private predecessor period ended October 2, 2005 and the 90 day private successor period ended December 31, 2005.

(2) Earnings before interest, taxes, depreciation, depletion and amortization, or "EBITDA" represents net income adjusted to exclude interest expense, income taxes, depreciation, depletion and amortization. "Adjusted EBITDA" represents EBITDA adjusted to exclude accretion of discount on asset retirement obligations, non-cash changes in the fair value of derivative financial instruments, commodity price risk management contracts termination expense, stock based compensation expense and non-recurring cash-out of options in Equity Buyout and other settlements. We have presented Adjusted EBITDA because it is the financial measure that is used in covenant calculations required under our credit agreement and compliance with the liquidity and debt incurrence covenants included in this agreement is considered material to us. Our computations of EBITDA and Adjusted EBITDA may differ from computations of similarly titled measures of other companies due to differences in the inclusion or exclusion of items in our computations as compared to those of others. EBITDA and Adjusted EBITDA are measures that are not prescribed by generally accepted accounting principles, or GAAP. EBITDA and Adjusted EBITDA specifically exclude changes in working capital, capital expenditures and other items that are set forth on a cash flow statement presentation of a company's operating, investing and financing activities. As such, we encourage investors not to use these measures as substitutes for the determination of net income, net cash provided by operating activities or other similar GAAP measures. See accompanying table.

(3) Net cash provided by (used in) operating activities for the twelve months ended December 31, 2005 includes $67.6 million related to the termination of commodity price risk management contracts and $49.3 million for income taxes related to the sale of Addison Energy.

(4) Oil and NGLs are converted to natural gas on the basis of six Mcf per one Bbl.

(5) Reserve information is based upon data contained in the reports of our independent petroleum engineers under SEC reporting parameters using prices and costs at the dates indicated before future income taxes.

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

	NYMEX spot price	
	Natural gas (per Mmbtu)	*Oil (per Bbl)*
December 31, 2003	$ 6.19	$ 32.52
December 31, 2004	6.18	43.33
December 31, 2005	10.08	61.03
December 31, 2006	**5.64**	**60.82**

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 because the tax characteristics of comparable companies can differ materially. 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,* 2003	2004	2005	**2006**
PV-10	$ 331.9	$ 700.4	$ 1,248.6	**$ 1,606.0**
Future income taxes	(243.1)	(588.9)	(1,097.6)	**(721.2)**
Discount of future income taxes at 10% per annum	137.2	362.2	672.3	**427.0**
Standardized Measure	$ 226.0	$ 473.7	$ 823.3	**$ 1,311.8**

Table to Accompany Footnote 2 (In millions)	Public predecessor	Private predecessor		Private predecessor		Successor		
	For the 209 day period from January 1, 2003 to July 28, 2003	For the 156 day period from July 29, 2003 to December 31, 2003	Non-GAAP combined 2003	Year ended December 31, 2004	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
Net income (loss)	$ 1.0	$ 4.1	$ 5.1	$ 6.0	$ (15.2)	$ 16.4	$ 1.2	$ 139.0
Interest expense	1.1	1.9	3.0	34.6	26.7	19.4	46.1	84.9
Income tax expense (benefit)	(0.2)	(7.8)	(8.0)	5.1	(63.7)	7.6	(56.1)	89.4
Depreciation, depletion and amortization	5.1	5.4	10.5	28.5	24.7	14.1	38.8	135.7
EBITDA	7.0	3.6	10.6	74.4	(27.5)	57.5	30.0	449.0
Cumulative affect of change in accounting principle	(0.2)	-	(0.2)	-	-	-	-	-
Income from derivative ineffectiveness and terminated hedges	(0.2)	-	(0.2)	-	-	-	-	-
Accretion of discount on asset retirement obligations	0.3	0.2	0.5	0.8	0.6	0.2	0.8	2.0
Non-cash change in fair value of derivative financial instruments	-	5.4	5.4	24.3	114.4	(22.0)	92.4	(169.2)
Commodity price risk management contracts termination expense	-	-	-	-	52.6	-	52.6	-
Stock based compensation expense	3.6	-	3.6	-	44.1	2.2	46.3	6.5
Equity in net income of TXOK Acquisition, Inc	-	-	-	-	-	(0.8)	(0.8)	(1.6)
Non-recurring Equity Buyout options and other settlements	-	-	-	-	29.6	-	29.6	-
Income from discontinued operations	(8.6)	(4.3)	(12.9)	(25.9)	(122.0)	-	(122.0)	-
Adjusted EBITDA	$ 1.9	$ 4.9	$ 6.8	$ 73.5	$ 91.8	$ 37.1	$ 128.9	$ 286.7
Income from discontinued operations	8.6	4.3	12.9	25.9	-	-	-	-
Interest expense	(1.1)	(1.9)	(3.0)	(34.6)	(26.7)	(19.4)	(46.1)	(84.9)
Income tax expense (benefit)	0.2	7.8	8.0	(5.1)	63.7	(7.6)	56.1	(89.4)
Amortization of deferred financing costs	0.4	0.1	0.5	3.9	1.3	2.4	3.7	4.7
Deferred income taxes	-	(7.8)	(7.8)	3.7	(59.5)	16.0	(43.5)	89.4
Gain on disposition of property, equipment, and other assets	-	-	-	-	(0.4)	-	(0.4)	-
Changes in operating assets and liabilities	(0.4)	7.1	6.7	17.8	0.6	(20.2)	(19.6)	21.2
Proceeds from sale of Enron claim	-	-	-	4.8	-	-	-	-
Commodity price risk management contracts termination expense	-	-	-	-	(52.6)	-	(52.6)	-
Non-recurring Equity Buyout options and other settlements	-	-	-	-	(29.6)	-	(29.6)	-
Gains from sales of marketable securities	(0.3)	-	(0.3)	-	-	-	-	-
Other	0.2	(0.1)	0.1	-	-	-	-	-
Net cash provided by (used in) operating activities of discontinued operations	10.9	7.1	18.0	28.9	(69.8)	-	(69.8)	-
Net cash provided by (used in) operating activities	$ 20.4	$ 21.5	$ 41.9	$ 118.8	$ (81.2)	$ 8.3	$ (72.9)	$ 227.7


• Total production increased 111% to 49.6 Bcfe in 2006
• Achieved 98% drilling success rate in 2006
• Total reserves exceeded 1.2 Tcfe at year-end 2006

To Our Fellow Shareholders

For EXCO, 2006 was another record breaking year. We closed $2.1 billion in acquisitions, and when combined with our successful capital program, we increased our proved reserves by 2.8 times. In addition, in February 2006 we completed an initial public offering raising proceeds of $662.2 million. Concurrent with closing our IPO, we acquired TXOK Acquisition, Inc. for $665.1 million. In April 2006, we acquired Power Gas Marketing and Transmission, Inc. for $113.0 million. In October 2006, we acquired Winchester Energy Company, Ltd. for $1.1 billion. The TXOK and Winchester acquisitions strengthened our positions in the East Texas/North Louisiana and Mid-Continent areas, while the Power Gas transaction enhanced our Appalachian position. During 2006, we also closed five property acquisitions totaling $221.1 million, adding assets primarily in East Texas/North Louisiana, Appalachia, and the Permian Basin.

“We closed $2.1 billion in acquisitions... increasing our proved reserves by 2.8 times.”

As we made acquisitions throughout the year, our 2006 capital budget was increased from an initial amount of $168.0 million. Our spending on capital activities in 2006 ultimately totaled $214.3 million, exclusive of acquisition and technology spending.

Our development drilling program in 2006 set new activity and success standards. We drilled 373 wells and completed 367 wells, resulting in a 98% success rate.

Approximately 91% of our capital was spent on our development drilling program, which is focused in our East Texas, Appalachia, Mid-Continent and Permian Basin areas. Across our entire portfolio, we have amassed more than 5,000 drilling locations and 1,000 exploitation projects and have increased our net acreage position to more than 1.5 million acres, as of year end 2006. Our drill bit finding and development cost per Mcfe in 2006 was $2.21. Our all-in finding and development cost per Mcfe was $1.99 for the three years ended 2006.

Harold L. Hickey
Vice President and
Chief Operating Officer

Evaluating a drilling opportunity (pictured left to right):
Wayne Gifford, Exploration Manager; Bill Reinhart, Geologist; and Steve Puckett, Vice President - Reservoir Engineering

"In 2006 our development drilling program set new success standards."

As a result of our capital program and acquisition activity, we increased our proved reserves, calculated at SEC spot prices, from 442 Bcfe at year end 2005 to 1,224 Bcfe at year end 2006. Similarly, we significantly increased production volumes, as we produced 49.6 Bcfe (89% natural gas) during 2006, a 111% increase over 2005 production.

With over 150 acquisitions under our belt since we took control of EXCO in December 1997, we have made a significant investment in 2006 and 2007 to provide a rock solid infrastructure from which to continue our growth. Several information technology initiatives were designed, tested and implemented over the last 18 months. These include outfitting our pumpers with electronic hand held devices to capture daily production from our more than 9,000 operated wells, migrating all of our business units onto one accounting application, and adding comprehensive drilling management software to our arsenal.

J. Douglas Ramsey, Ph.D.
Vice President,
Chief Financial
Officer and Treasurer

In 2007, we are focused on pursuing additional acquisitions in our core areas in East Texas, Appalachia, Mid-Continent and the Permian Basin, with a continued emphasis on acquisitions of producing properties with significant development drilling potential. In March 2007, we acquired the Vernon Field in North Louisiana from Anadarko Petroleum for $1.5 billion, followed in May by an acquisition of certain Anadarko Mid-Continent assets for $504 million. In March 2007, we completed a $2.0 billion offering of Preferred Stock, $390 million of which was issued at a 7% dividend rate convertible into common stock at $19 per share, and $1.61 billion of which was issued at an 11% dividend rate and is convertible into the same terms as the 7% Preferred Stock pending shareholder approval at our upcoming annual meeting. Upon shareholder approval, all of the Preferred Stock will be at a 7% rate and convertible into common stock at $19 per share.

Our development drilling program in 2007 continues at a record-setting pace, with a total capital budget exceeding $500 million and funding 577 planned wells. Approximately 80% of our budget will be spent on drilling and completion activity.

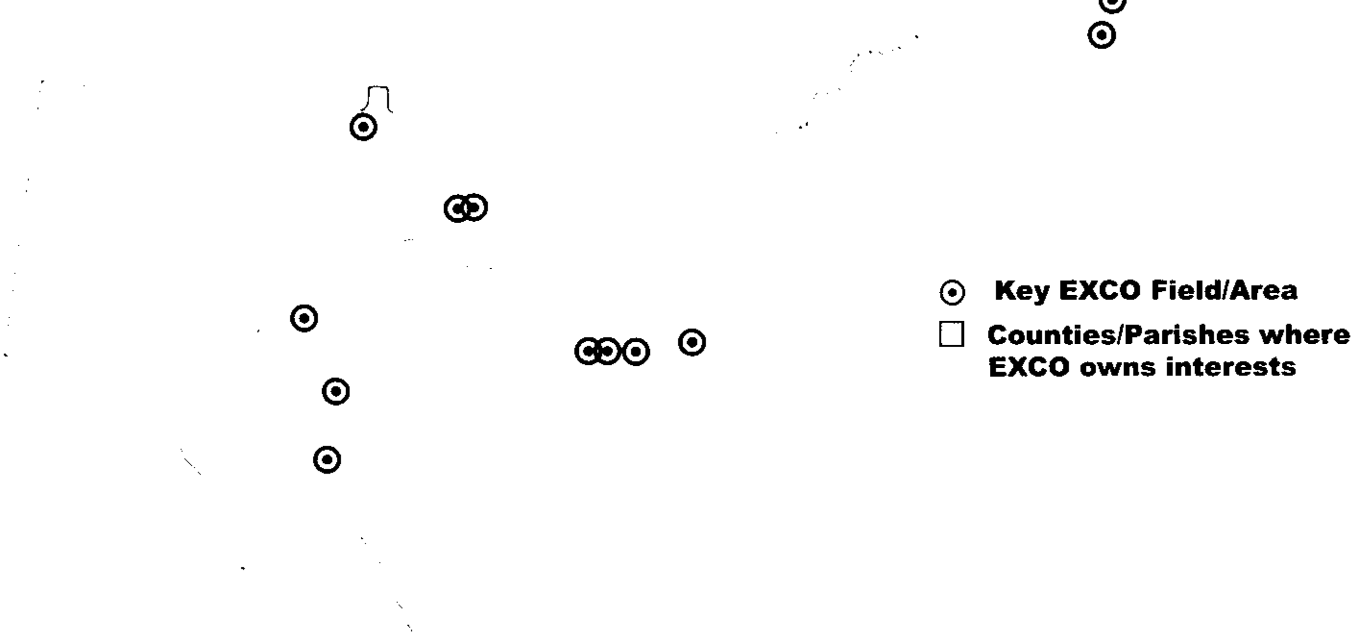
Our business development and acquisition engineering teams are evaluating numerous acquisition opportunities in all of our focus areas and will continue to apply our very disciplined approach to valuation and deal structuring.

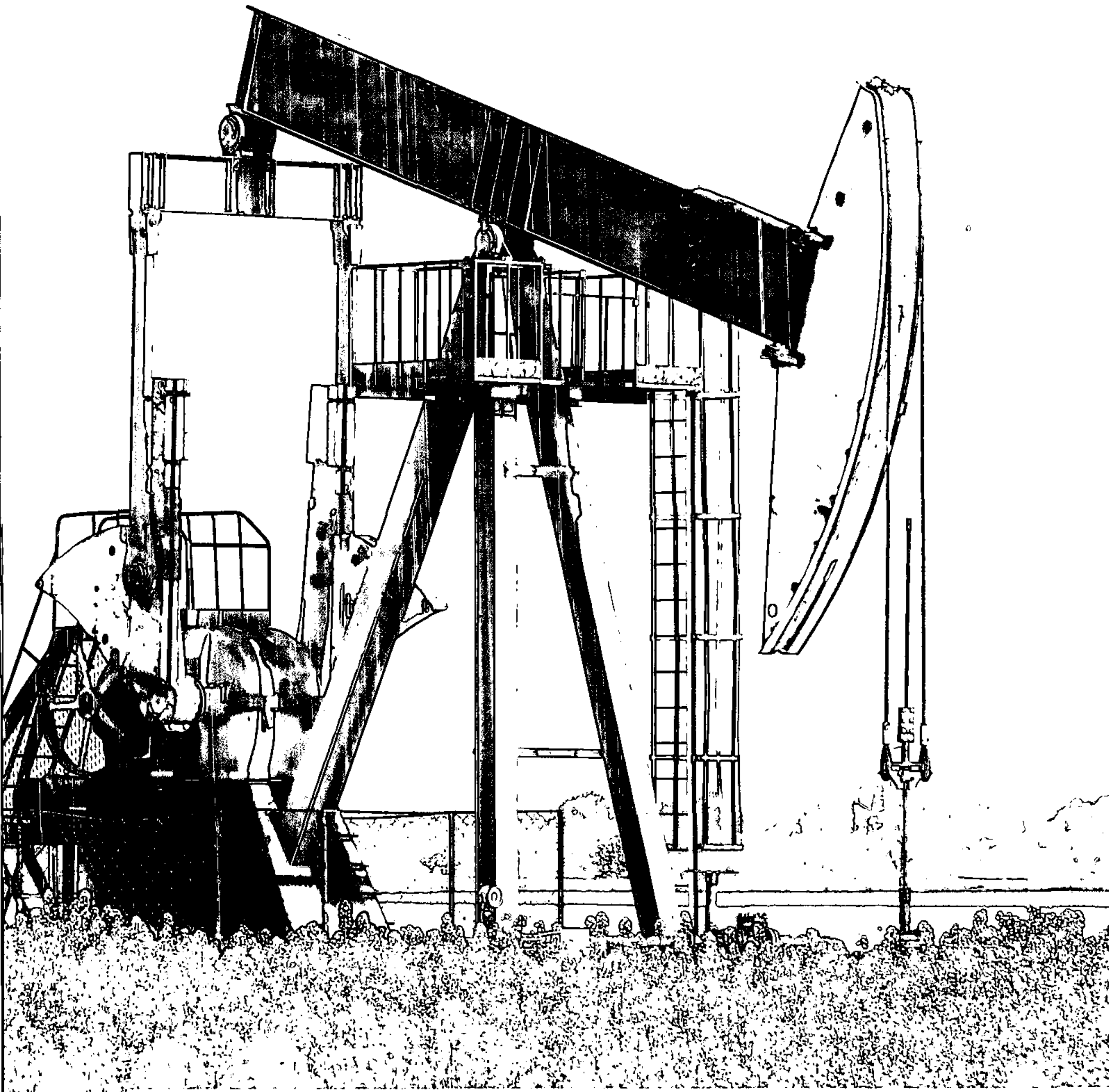
We once again would like to take this opportunity to thank you for your trust in the EXCO team. Our workforce, which now exceeds 600 full-time employees, is dedicated to increasing the value of your shares.

Sincerely,

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

Stephen F. Smith
Vice Chairman of the
Board and President





- Adjusted EBITDA up 122% to $286.7 million in 2006
- PV-10 increased to $1.6 billion at year-end 2006
- Drilled and completed 367 wells in 2006

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2006

OR

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

For the Transition Period from to

Commission File Number 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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

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

As of March 1, 2007, the registrant had 104,221,015 outstanding shares of common stock, par value $.001 per share, which is its only class of 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 $809,940,000.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement to be furnished to shareholders in connection with its 2007 Annual Meeting of Shareholders are incorporated by reference in Part III, Items 10-14 of this Annual Report on Form 10-K.

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EXCO RESOURCES, INC.

PART I

ITEM 1. BUSINESS

General

Unless the context requires otherwise, references in this annual report to "EXCO," "we," "us," and "our" are to EXCO Resources, Inc., or EXCO Resources, its consolidated subsidiaries and EXCO Holdings Inc., or EXCO Holdings, our former parent company, which merged into and was acquired by EXCO Holdings II, Inc., or Holdings II, in October 2005. On February 14, 2006, EXCO Holdings merged with and into EXCO Resources concurrent with our initial public offering, or IPO. As such, all periods presented reflect the merger and include EXCO Holdings.

The year ended December 31, 2004 and the period beginning January 1, 2005 and ending on October 2, 2005 are referred to as predecessor. The predecessor period represents the accounting period up to the Equity Buyout. For more information about the Equity Buyout, see "—Significant transactions during 2005." The period beginning October 3, 2005 and ending on December 31, 2006 is 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 26.

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, 2006, our Proved Reserves were approximately 1.2 Tcfe, of which 92% were natural gas and 60% were Proved Developed Reserves. As of December 31, 2006, the related PV-10 of our Proved Reserves was $1.6 billion, and the Standardized Measure of our Proved Reserves was $1.3 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, 2006, we produced 49.6 Bcfe of oil and natural gas. Based on our December 2006 average daily production, this translates to a reserve life of approximately 16.8 years. For the twelve month period ended December 31, 2006, we generated $355.8 million of oil and natural gas revenues.

We are a party to two pending acquisitions from Anadarko Petroleum Corporation and its affiliates, or Anadarko, that we expect will have a significant impact on our results of operations and financial condition during 2007. In January 2007, we sold our producing properties and remaining undeveloped drilling locations in the Wattenberg Field area of the DJ Basin, Colorado for $131.9 million. For more information about the pending acquisitions from Anadarko and the sale of our Wattenberg Field operations, see "—Significant subsequent events." On February 14, 2007, we issued a press release pursuant to Rule 135c of the Securities Act of 1933 to announce a proposed private placement of up to $2.0 billion of preferred stock. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, capital resources and capital commitments—Proposed recapitalization."

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, 2004 to December 31, 2006, we drilled 584 wells and completed 572 wells resulting in a 98% drilling success rate. We have identified over 6,225 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. 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 and our pending acquisitions from Anadarko are examples of this strategy.

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

  We 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 operations for $443.4 million in February 2005 and the sale of our Wattenberg Field operations in Colorado for $131.9 million in January 2007.

- ***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 investment, 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 4.7 Bcfe to 1.2 Tcfe at December 31, 2006, and our average daily production increased from less than 1 Mmcfe per day in 1997 to 200.0 Mmcfe per day in December 2006. Importantly, as of March 1, 2007, our management team and employees (excluding our outside directors) own approximately 9.3% of our fully-diluted capital stock and our outside directors or their affiliates own approximately 15.4% of our fully-diluted capital stock, 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, 2006, we were the operator of 7,794 gross wells which represented 90% of our Proved Reserves.

Significant transactions during 2005

Sale of Addison. On February 10, 2005, we sold Addison Energy Inc., or Addison, our former wholly-owned subsidiary through which all of our Canadian operations were conducted, for an aggregate sales price of Cdn. $551.3 million ($443.4 million). Of this amount, Cdn. $90.1 million ($72.1 million) was used to repay in full all outstanding balances under Addison's credit facility, while Cdn. $56.2 million ($45.2 million) was withheld and was remitted to the Canadian government for estimated income taxes resulting from the sale of the stock. Prior to the sale of Addison, on February 9, 2005, Addison made an earnings and profits dividend (as calculated under U.S. tax law) to us in an amount of Cdn. $74.5 million ($59.6 million). The dividend was subject to Canadian tax withholding of Cdn. $3.7 million ($3.0 million). See "Note 5. Sale of Addison Energy Inc." of the notes to our consolidated financial statements for additional information.

TXOK acquisition. On September 16, 2005, Holdings II formed TXOK for the purpose of acquiring ONEOK Energy Resources Company and ONEOK Energy Resources Holdings, L.L.C., collectively ONEOK Energy. Prior to TXOK's acquisition of ONEOK Energy, we owned all of the issued and outstanding common stock of TXOK and BP EXCO Holdings LP, an entity controlled by Mr. Boone Pickens, one of our directors, held all of the outstanding shares of TXOK preferred stock. On September 27, 2005, TXOK completed the acquisition of ONEOK Energy for an aggregate purchase price of approximately $634.8 million after contractual adjustments. Effective upon closing, ONEOK Energy Resources Company and ONEOK Energy Resources Holdings, L.L.C. became wholly-owned subsidiaries of TXOK. We purchased an additional $20.0 million of common stock of TXOK on October 7, 2005, which investment represented an 11% equity interest and a 10% voting interest in TXOK. The preferred stock of TXOK held by BP EXCO Holdings LP represented the remaining 89% equity interest and 90% voting interest of TXOK.

TXOK funded the acquisition of ONEOK Energy with (i) $20.0 million in private debt financing, $15.0 million of which was provided by Mr. Boone Pickens, one of our directors, which has since been repaid; (ii) the issuance of $150.0 million of the 15% Series A Convertible Preferred Stock of TXOK, or the TXOK preferred stock, to BP EXCO Holdings LP, an entity controlled by Mr. Pickens; (iii) approximately $308.8 million of borrowings under the revolving credit facility of TXOK, or the TXOK credit facility; and (iv) $200.0 million of borrowings under the second lien term loan facility of TXOK, or the TXOK term loan.

Concurrent with our IPO on February 14, 2006, we redeemed all of the outstanding TXOK preferred stock, which represented 90% of the voting rights of TXOK. The redemption price for the TXOK preferred stock was (a) cash in the amount of approximately $158.8 million and (b) 388,889 shares of common stock of EXCO Resources. Once the TXOK preferred stock was redeemed, our acquisition of TXOK, or the TXOK acquisition, was complete and it became our wholly-owned subsidiary. The properties TXOK acquired in the TXOK acquisition included 1,057 gross (453.1 net) producing oil and natural gas wells in Texas and Oklahoma at December 31, 2005. TXOK had Proved Reserves, estimated as of December 31, 2005, of approximately 223.7 Bcfe of oil and natural gas, and 151 miles of natural gas gathering lines. The acquired properties produced an average of 970 Bbls of oil per day and 46.9 Mmcf of natural gas per day during 2005. For more information about the TXOK acquisition, see "Note 16. Related party transactions" of the notes to our consolidated financial statements.

Equity Buyout. On October 3, 2005, Holdings II, an entity formed by our management, purchased 100% of the outstanding equity securities of EXCO Holdings in an equity buyout, or the Equity Buyout, for an aggregate price of approximately $699.3 million, resulting in a change of control and a new basis of accounting. To fund the Equity Buyout, Holdings II raised $350.0 million in interim debt financing, including $0.7 million for working capital, from a group of lenders and $183.1 million of equity financing from new institutional and other investors as well as stockholders of EXCO Holdings. In addition, management and other stockholders of EXCO Holdings exchanged $166.9 million of their EXCO Holdings common stock for Holdings II common stock. EXCO Holdings' majority stockholder sold all of its EXCO Holdings common stock for cash. Promptly following the completion of the Equity Buyout, Holdings II merged with and into EXCO Holdings. As a result of the merger, each outstanding share of Holdings II common stock was cancelled and exchanged for one share of EXCO Holdings common stock and all shares of EXCO Holdings common stock held by Holdings II were cancelled. For more information about the Equity Buyout, see "Note 1. Organization—The Equity Buyout" of the notes to our consolidated financial statements.

Repurchase of senior notes pursuant to a change of control tender offer. In connection with the Equity Buyout, we were required to offer to repurchase our 7¼% Senior Notes due 2011, or senior notes, for a purchase price of 101%. As a result, we repurchased $5.3 million principal amount of senior notes on December 13, 2005.

Significant transactions during 2006

Initial public offering. On February 14, 2006, EXCO Resources completed its IPO of 50,000,000 shares of its common stock for aggregate net proceeds to EXCO Resources of $617.5 million after underwriters' discount. J.P. Morgan Securities Inc., Bear, Stearns & Co. Inc. and Goldman, Sachs & Co. acted as joint book running managers for the IPO.

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 and redemption premium, issued to a related party 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 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.

Concurrent with the consummation of the IPO, including the redemption of the TXOK preferred stock, EXCO Holdings merged with and into EXCO Resources, with EXCO Resources as the surviving corporation. The outstanding shares of EXCO Holdings common stock were cancelled as a result of the merger and such shares were exchanged for the same number of shares of EXCO Resources common stock. As a result of the merger, TXOK became a wholly-owned subsidiary of EXCO Resources and TXOK and its subsidiaries became guarantors under the indenture governing our senior notes, or the Indenture. EXCO Resources also became a guarantor under the TXOK credit facility and TXOK likewise became a guarantor under EXCO Resources' credit agreement.

On February 21, 2006, EXCO Resources issued 3,615,200 additional shares of its common stock pursuant to an exercise by the underwriters of their over-allotment option for net proceeds to EXCO Resources of approximately $44.7 million. The net proceeds were used to reduce outstanding indebtedness under EXCO Resources' credit agreement.

Summary of 2006 acquisition activity. During 2006, we completed the following acquisitions of oil and natural gas properties and undeveloped acreage, including the acquisition of Winchester, our largest acquisition to date. 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)	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:			
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

Redemption of preferred stock and acquisition 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 TXOK preferred stock. Once the TXOK preferred stock was redeemed, our acquisition of TXOK 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.

Acquisition of Power Gas Marketing & Transmission, Inc. On April 28, 2006, our wholly-owned subsidiary, 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 the EXCO Resources credit agreement, we paid the assumed debt and terminated the assumed derivative financial instruments. The acquisition was accounted for as a purchase in accordance with Statement of Financial Accounting Standards, or SFAS, No. 141 "Accounting for Business Combinations," or SFAS No. 141.

Winchester acquisition. On October 2, 2006, our wholly-owned subsidiary, Winchester Acquisition, LLC, or Winchester Acquisition, acquired Winchester and its affiliated entities from Progress Fuels Corporation, or PFC, for approximately $1.1 billion in cash. The acquisition consisted of producing and undeveloped oil and natural gas properties located in East Texas and North Louisiana, six gathering systems with approximately 300 miles of pipe and a 53 mile pipeline system. The average acquired working interest was 76% with an average 58% net revenue interest. The properties are located in the Cotton Valley, Hosston and Travis Peak trends in East Texas and North Louisiana. As of the closing date, the properties included approximately 734 gross drilling locations, 48% of which were proved, and approximately 114,000 net acres of leasehold of which 63% was held by production.

Concurrent with the acquisition, we contributed Winchester Acquisition to our wholly-owned subsidiary, EXCO Partners, LP, or EXCO Partners. Accordingly, Winchester Acquisition is now an indirect subsidiary of EXCO Partners. In addition, we also contributed all of our East Texas oil and natural gas properties, related pipeline and gathering systems, compressors and other production related equipment, and contracts, including financial derivative instruments associated with our East Texas production, to EXCO Partners in exchange for a payment to EXCO Resources of $150.0 million in cash. The proceeds were applied to reduce indebtedness outstanding under the EXCO Resources credit agreement. Included in the assets conveyed to EXCO Partners were four of our subsidiaries, ROJO Pipeline, LP (f/k/a ROJO Pipeline, Inc.), TXOK Energy Resources Holdings, LLC, TXOK Texas Energy Holdings, LLC and TXOK Texas Energy Resources, L.P. Following the equity contribution, these entities are no longer guarantors or restricted subsidiaries under the EXCO Resources credit agreement or the Indenture. EXCO Partners, its subsidiaries and its general partners are deemed unrestricted subsidiaries under the Indenture and the EXCO Resources credit agreement.

To finance the acquisition and the $150.0 million payment to EXCO Resources for our East Texas assets, EXCO Partners' wholly-owned subsidiary, EXCO Partners Operating Partnership, LP, or EPOP, entered into a Senior Revolving Credit Agreement, or EPOP Revolving Credit Facility, and a Senior Term Credit Agreement, or EPOP Senior Term Credit Agreement with a group of lenders led by JPMorgan Chase Bank, N.A. In connection with the arrangement of the EPOP Senior Term Credit Agreement, the lenders required us to enter into an Equity Contribution Agreement, or Contribution Agreement, dated October 2, 2006, as amended and restated on October 4, 2006 and October 13, 2006. For more information about the EPOP Revolving Credit Facility, the EPOP Senior Term Credit Agreement and the Contribution Agreement, see "Item 7. Management's discussion and analysis of financial condition and results of operations—Our liquidity, capital resources and capital commitments."

Significant subsequent events

Pending acquisition of Vernon Assets

On December 22, 2006, Vernon Holdings, LLC, or Vernon, our wholly-owned subsidiary, entered into a Purchase and Sale Agreement, or the Vernon Purchase Agreement, with Anadarko Petroleum Corporation and Anadarko Gathering Company. Subject to the terms and conditions in the Vernon Purchase Agreement, Vernon will acquire substantially all of the oil and natural gas properties and related assets, including derivative financial instruments in respect of a significant portion of estimated production for 2007, 2008 and 2009, or collectively the Vernon Assets, of Anadarko in the Vernon and Ansley Fields located in Jackson Parish, Louisiana.

Vernon will pay Anadarko a purchase price of approximately $1.6 billion in cash for the Vernon Assets, subject to certain purchase price adjustments. The purchase price will be: (i) reduced by proceeds earned (including, from the sale of hydrocarbons), and increased by costs incurred, with respect to the operation of the Vernon Assets during the period from 7:00 a.m., local time, on November 1, 2006, or the Effective Time, to the closing date, (ii) reduced by the aggregate amount of material title defects and material environmental defects exceeding $32.0 million, (iii) increased by the aggregate amount of material aggregate title benefits exceeding $32.0 million, (iv) reduced by the aggregate amounts payable to owners of working interests and other interests in the Vernon Assets held in suspense as of the closing date, (v) increased or reduced by the net amount of any gas imbalances as of the Effective Time, and (vi) increased by the value of merchantable stored hydrocarbons attributable to the Vernon Assets as of the Effective Time. In connection with the acquisition, derivative financial instruments in respect of a significant portion of estimated production for 2007, 2008 and 2009 were entered into by the seller and will be assumed by EXCO.

The Vernon Purchase Agreement contains customary representations, warranties and covenants. The acquisition is expected to close on or about March 30, 2007, subject to the satisfaction of various closing conditions, including, among others, (i) the aggregate amount of uncured title defects, environmental defects and casualty losses, net of title benefits, not exceeding $160.0 million and (ii) the sum of allocated values not exceeding $32.0 million for any Vernon Assets that are retained by Anadarko because of the failure to obtain, prior to closing, third-party consents required to transfer such Vernon Assets.

Concurrently with the execution of the Vernon Purchase Agreement, Vernon deposited with Anadarko an earnest money deposit in the amount of $80.0 million to be applied against the purchase price at closing or, if Anadarko terminates the Vernon Purchase Agreement because Vernon has materially breached Vernon's representations, warranties or covenants under the Vernon Purchase Agreement, to be retained by Anadarko, as its sole and exclusive remedy, as liquidated damages. If the Vernon Purchase Agreement is terminated for any reason other than as stated in the preceding sentence, Anadarko is obligated to return the deposit to Vernon.

Anadarko has agreed to indemnify Vernon after the closing, subject to certain limitations, for losses incurred by Vernon to the extent resulting from, arising out of or relating to (i) Anadarko's breach of any representation or warranty of Anadarko contained in the Vernon Purchase Agreement or in any certificates furnished in connection therewith, (ii) Anadarko's failure to perform any covenant or agreement contained in the Vernon Purchase Agreement or in any certificates furnished in connection therewith, (iii) liabilities associated with assets or properties not part of the Vernon Assets, (iv) scheduled litigation and other proceedings and other litigation and other proceedings that arise out of or are attributable to Anadarko's ownership or operation of the Vernon Assets after December 22, 2006 but before the closing, (v) litigation and other proceedings that arise after closing for personal injury or death arising and occurring before the closing which is attributable to Anadarko's ownership or operation of the Vernon Assets, (vi) obligations or liabilities attributable to scheduled incidences of noncompliance with laws by Anadarko, (vii) certain retained employee liabilities, and (viii) any off-site environmental liabilities occurring prior to the closing that relate to the Vernon Assets. Vernon has agreed to indemnify Anadarko after the closing, subject to certain limitations, for losses incurred by Anadarko to the extent resulting from, arising out of or relating to (a) Vernon's breach of any representation or warranty of Vernon contained in the Vernon Purchase Agreement or in any certificates furnished in connection therewith, (b) Vernon's failure to perform any covenant or agreement contained in the Vernon Purchase Agreement or in any certificates furnished in connection therewith, (c) the ownership, use or operation of the Vernon Assets after the Effective Time, (d) other than off-site environmental liabilities retained by Anadarko, any environmental liabilities associated with the Vernon Assets, and (e) certain obligations and liabilities of Anadarko with respect to the Vernon Assets that will be assumed by Vernon at the closing. Neither Anadarko, on the one hand, nor Vernon, on the other hand, will be obligated to indemnify the other (and other related indemnified persons specified in the Vernon Purchase Agreement) for losses until the amount of all losses incurred by such person and such other indemnified persons exceeds, in the aggregate, $40.0 million, in which event the party seeking indemnification may recover all losses incurred in excess of $40.0 million, up to a maximum liability of $400.0 million.

On December 22, 2006, in connection with the Vernon Purchase Agreement, EXCO entered into a guaranty agreement, or Vernon Guaranty, with Anadarko to guarantee Vernon's payment obligations and Vernon's performance of all covenants required to be performed by it pursuant to the terms of the Vernon Purchase Agreement and ancillary documents delivered in connection therewith. EXCO is the primary obligor under the Vernon Guaranty and must pay or perform, or cause the payment or performance, of any obligation not punctually paid or performed when due by Vernon. EXCO is not obligated to pay or perform any obligation to the extent that Vernon would not be required to pay or perform such obligation due to any defenses available to Vernon.

Pending acquisition of Southern Gas Assets

On February 1, 2007, EXCO Resources entered into a Purchase and Sale Agreement, or the Southern Gas Purchase Agreement, with Anadarko Petroleum Corporation, Anadarko E&P Company, LP, Howell Petroleum Corporation, and Kerr-McGee Oil & Gas Onshore LP, whereby, subject to the terms and conditions in the Southern Gas Purchase Agreement, EXCO Resources will acquire substantially all of the oil and natural gas properties and related assets, including derivative financial instruments in respect of a significant portion of estimated production for 2007, 2008 and 2009, or collectively the Southern Gas Assets, of Anadarko in multiple fields located in the Mid-Continent, South Texas and Gulf Coast areas, which fields are primarily located in Oklahoma, Texas and Louisiana.

EXCO Resources will pay Anadarko a purchase price of approximately $860.0 million in cash for the Southern Gas Assets, subject to certain purchase price adjustments. The purchase price will be: (i) reduced by proceeds earned (including, from the sale of hydrocarbons), and increased by costs incurred, with respect to the operation of the Southern Gas Assets during the period from 7:00 a.m., local time, on

January 1, 2007, or the Effective Date, to the closing date, (ii) reduced by the value of any Southern Gas Asset not conveyed to EXCO in the event a required preference right or transfer requirement has not been satisfied or waived as of the closing, (iii) reduced by the aggregate amount of material title defects and material environmental defects exceeding $17.0 million, (iv) increased by the aggregate amount of material aggregate title benefits exceeding $17.0 million, (v) reduced by the aggregate amounts payable to owners of working interests and other interests in the Southern Gas Assets held in suspense as of the closing date, (vi) reduced by the net amount of any gas imbalances as of the Effective Date, and (vii) increased by the value of merchantable stored hydrocarbons attributable to the Southern Gas Assets as of the Effective Date.

The Southern Gas Purchase Agreement contains customary representations, warranties and covenants. The acquisition is expected to close on or about May 2, 2007, subject to the satisfaction of various closing conditions, including, among others, (i) the termination of any applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, (ii) the aggregate amount of uncured title defects, environmental defects and casualty losses, net of title benefits, not exceeding $86.0 million, and (iii) the sum of allocated values not exceeding $17.2 million for any Southern Gas Assets that are retained by Anadarko because of the failure to obtain, prior to closing, third-party consents required to transfer such Southern Gas Assets.

In connection with the execution of the Southern Gas Purchase Agreement, EXCO Resources deposited with Anadarko an earnest money deposit in the amount of $43.0 million to be applied against the purchase price at closing or, if Anadarko terminates the Southern Gas Purchase Agreement because EXCO Resources has materially breached its representations, warranties or covenants under the Southern Gas Purchase Agreement, to be retained by Anadarko, as its sole and exclusive remedy, as liquidated damages. If the Southern Gas Purchase Agreement is terminated for any reason other than as stated in the preceding sentence, Anadarko is obligated to return the deposit to EXCO Resources.

Anadarko has agreed to indemnify EXCO Resources after the closing, subject to certain limitations, for losses incurred by EXCO Resources to the extent resulting from, arising out of or relating to (i) Anadarko's breach of any representation or warranty of Anadarko contained in the Southern Gas Purchase Agreement or confirmed in any certificate furnished in connection therewith, (ii) Anadarko's failure to perform any covenant or agreement contained in the Southern Gas Purchase Agreement or confirmed in any certificate furnished in connection therewith, (iii) liabilities associated with assets or properties not part of the Southern Gas Assets, (iv) certain scheduled litigation and other proceedings and other litigation and other proceedings that arise out of or are attributable to Anadarko's ownership or operation of the Southern Gas Assets after February 1, 2007 but before the closing, (v) litigation and other proceedings that arise after closing for personal injury or death arising and occurring before the closing which is attributable to Anadarko's ownership or operation of the Southern Gas Assets, (vi) obligations or liabilities attributable to scheduled incidences of noncompliance with laws by Anadarko, (vii) certain retained employee liabilities, and (viii) any off-site environmental liabilities occurring prior to the closing that relate to the Southern Gas Assets. EXCO Resources has agreed to indemnify Anadarko after the closing, subject to certain limitations, for losses incurred by Anadarko to the extent resulting from, arising out of or relating to (a) EXCO Resources' breach of any representation or warranty contained in the Southern Gas Purchase Agreement or confirmed in any certificate furnished in connection therewith, (b) EXCO Resources' failure to perform any covenant or agreement contained in the Southern Gas Purchase Agreement or confirmed in any certificate furnished in connection therewith, (c) the ownership, use or operation of the Southern Gas Assets after the Effective Date, (d) other than off-site environmental liabilities retained by Anadarko, any environmental liabilities associated with the Southern Gas Assets, and (e) certain obligations and liabilities of Anadarko with respect to the Southern Gas Assets that will be assumed by EXCO Resources at the closing. Neither Anadarko, on the one hand, nor EXCO Resources, on the other hand, will be obligated to indemnify the other (and other related indemnified persons specified in the Southern Gas Purchase Agreement) for losses until the amount of all losses incurred by such person and such other indemnified persons exceeds, in the aggregate, $21.5 million, in which event the party seeking indemnification may recover all losses incurred in excess of $21.5 million, up to a maximum liability of $215.0 million.

In connection with the pending acquisitions, the following derivative financial instruments covering estimated production for 2007, 2008 and 2009 were entered into by the seller and will be assumed by us:

Vernon Assets

	Swaps			
(in thousands, except average contract prices)	NYMEX gas volume—Mmbtus	Weighted average contract price per Mmbtu	NYMEX oil volume—Bbls	Weighted average contract price per Bbl
Q1 2007	12,600	$7.35	—	$—
Q2 2007	12,740	7.35	—	—
Q3 2007	12,880	7.35	—	—
Q4 2007	12,880	7.35	—	—
2008	38,430	8.16	—	—
2009	32,850	7.84	—	—

Southern Gas Assets

	Swaps			
(in thousands, except average contract prices)	NYMEX gas volume—Mmbtus	Weighted average contract price per Mmbtu	NYMEX oil volume—Bbls	Weighted average contract price per Bbl
Q1 2007	4,130	$7.51	177	$54.32
Q2 2007	6,370	7.43	273	56.03
Q3 2007	5,520	7.58	184	57.51
Q4 2007	5,520	8.28	184	58.67
2008	18,300	8.14	732	59.60
2009	14,600	7.83	730	59.98

To ensure that EXCO has sufficient financing to complete the acquisitions from Anadarko of oil and natural gas properties in the Vernon and Ansley Fields in Jackson Parish, Louisiana, EXCO received a revised commitment letter dated as of February 1, 2007, from J.P. Morgan Securities Inc. and JPMorgan Chase Bank, N.A. This commitment letter supersedes and replaces the commitment letter we received on December 22, 2006, in conjunction with our entering into the Vernon Purchase Agreement. The new commitment letter, as subsequently supplemented, provides for a senior secured revolving credit facility commitment in the amount of $1.8 billion and an undertaking to arrange a bridge loan facility in the amount of $1.1 billion if requested, or collectively the new credit facilities. If used to finance these acquisitions, the new credit facilities will contain customary representations, warranties and covenants, and the closing of the new credit facilities will be subject to the satisfaction of customary closing conditions. EXCO is also pursuing other financing alternatives, including a proposed private placement of preferred stock. For a discussion of the proposed terms of the preferred stock, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, capital resources and capital commitments—Proposed recapitalization."

Sale of Wattenberg Field

In January 2007, we completed the sale of our producing properties and remaining undeveloped drilling locations in the Wattenberg Field area of the DJ Basin, Colorado. The transaction included substantially all of our assets in the area. Proved reserves sold were approximately 55.7 Bcfe. The adjusted purchase price paid at closing was $131.9 million.

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, 2006:

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	513.7	$ 614.1	100.7	14.0
Appalachia	444.7	504.7	45.0	27.1
Mid-Continent	105.5	239.7	27.0	10.7
Permian	85.4	159.8	17.4	13.4
Rockies	71.8	82.8	7.1	27.7
Gulf Coast/Other	2.4	4.9	2.8	2.3
Total	1,223.5	$1,606.0	200.0	16.8

Areas	Identified drilling locations(4)	Identified exploitation projects(5)	Total gross acreage	Total net acreage(6)
East Texas/North Louisiana	811	455	187,198	153,875
Appalachia	3,120	84	887,662	818,677
Mid-Continent	190	175	179,393	105,875
Permian	710	47	63,055	34,896
Rockies	264	355	190,868	157,820
Gulf Coast/Other	5	9	7,673	4,555
Total	5,100	1,125	1,515,849	1,275,698

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

(2) The PV-10 data used in this table is based on December 31, 2006 spot prices of $5.64 per Mmbtu for natural gas and $60.82 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, 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, 2006 was $1.3 billion. The Standardized Measure represents the PV-10 after giving effect to income taxes, and is calculated in accordance with 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, 2006:

(in millions)	
PV-10	$1,606.0
Future income taxes	(721.2)
Discount of future income taxes at 10% per annum	427.0
Standardized Measure	$1,311.8

(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, 2,719 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, 523 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 46,756, 60,730, and 36,426 net acres with leases expiring in 2007, 2008 and 2009, respectively.

Our development and exploitation project areas

East Texas/North Louisiana

The East Texas area is a part of the Cotton Valley Sand trend, which covers parts of the East Texas Basin and the Northern Louisiana Salt Basin. The TXOK acquisition significantly enhanced our position in this area. 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.

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, 2006, we had Proved Reserves of 513.7 Bcfe and 1,179 gross producing wells. We operate 96% of our Proved Reserves in this area. 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 Pettit Lime at depths of 7,000 to 8,500 feet and Travis Peak Sands at depths of 7,800 to 9,000 feet. Our natural gas is gathered through our own gathering lines in these fields. We currently plan to drill 125 wells during 2007.

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 from the area typically commands a higher well head 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.

Central Pennsylvania Area

The Central Pennsylvania Area stretches across 11 counties in central Pennsylvania. At December 31, 2006, we had Proved Reserves of 203.4 Bcfe and 1,736 gross producing wells. We operate 99.7% of our Proved Reserves in this area. Production is primarily from the Venango, Bradford, and Elk groups at depths from 1,800 to 4,600 feet. We currently plan to drill 156 wells during 2007.

Northeast Ohio Area

The Northeast Ohio Area includes a 14 county area located south of Lake Erie in northeastern Ohio. At December 31, 2006, we had Proved Reserves of 49.2 Bcfe and 854 gross producing wells. We operate 99.97% of our Proved Reserves in this area. Production in the Northeast Ohio area is primarily from the Silurian Clinton Sandstone found at depths of 3,500 to 5,600 feet. We currently plan to drill 36 wells during 2007.

Jamestown Area

The Jamestown Area is located in western Pennsylvania. At December 31, 2006, we had Proved Reserves of 19.8 Bcfe. We operate 162 gross producing wells which represent 100% of our Proved Reserves in the area. Production is primarily from the Medina Sandstone formation at depths of 4,500 to 5,100 feet. We currently plan to drill 31 wells during 2007.

Ravenswood Area

The Ravenswood Area is located in the western portion of West Virginia. At December 31, 2006, we had Proved Reserves of 45.9 Bcfe and 593 gross producing wells. We operate 98.1% of our Proved Reserves in this area. Production in the Ravenswood area is primarily from the Mississippian and Devonian formations at depths of 2,500 to 4,400 feet. We currently plan to drill 11 wells during 2007.

Maben Area

The Maben Area is located in southwest West Virginia. At December 31, 2006, we had Proved Reserves of 31.4 Bcfe and 317 gross producing wells. We operate 100% of our Proved Reserves in this area. In Maben, we produce from the Mississippian and Devonian formations at depths ranging from 1,500 to 5,500 feet. Our drilling activity targets seven separate shallow formations, with a typical well completed in two or more horizons. We currently plan to drill nine wells during 2007.

Adamsville Area

The Adamsville Area is located in south central Ohio. At December 31, 2006, we had Proved Reserves of 10.6 Bcfe and 336 gross producing wells. We operate 98.9% of our Proved Reserves in this area. Adamsville produces from the Clinton reservoir and the Knox series at depths from 3,000 to 6,300 feet. We currently plan to drill seven wells during 2007.

Mid-Continent

Our Mid-Continent area includes parts of Oklahoma, southwestern Kansas and the Texas Panhandle. The major properties in the Mid-Continent area were acquired in the TXOK acquisition and 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

Our Mocane-Laverne Field, which was acquired in the TXOK acquisition, is located in Beaver, Harper and Ellis Counties of Oklahoma. At December 31, 2006, we had Proved Reserves of 41.7 Bcfe and we had 497 gross producing wells. We operate 77% of our Proved Reserves. At Mocane-Laverne, we are targeting eight productive formations at depths from 2,500 to 9,000 feet. We currently plan to drill 22 wells during 2007.

Cement Field

Our Cement Field, which was acquired in the TXOK acquisition, is located in Caddo and Grady Counties of Oklahoma. At December 31, 2006, we had Proved Reserves of 27.0 Bcfe and we had 134 gross producing wells, all operated by others. Production in the Cement field is primarily from multi-pay Pennsylvanian formations at depths of 4,500 to 18,000 feet. We currently plan to participate in the drilling of eight wells during 2007.

Chitwood Field

Our Chitwood Field, which was acquired in the TXOK acquisition, is near our Cement Field and is located in Grady County, Oklahoma. At December 31, 2006, we had Proved Reserves of 21.7 Bcfe and we had 55 gross producing wells. We operate 65% of our Proved Reserves. At Chitwood, we are targeting four productive formations at depths of 15,000 to 17,600 feet. We currently plan to drill six wells during 2007.

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

Our Sugg Ranch Field is located primarily in Irion County, Texas. At December 31, 2006, we had Proved Reserves of 33.7 Bcfe and 88 gross producing wells, all operated by others. At Sugg Ranch, production is primarily from the Canyon Sand depths of 6,700 to 7,300 feet. We currently plan to participate in the drilling of 84 wells during 2007.

Our oil and natural gas reserves

The following tables summarize historical information regarding Proved Reserves at December 31, 2004, 2005 and 2006 and exclude information with respect to Canada as a result of the sale of Addison in February 2005. The historical information was prepared in accordance with the rules and regulations of the Securities and Exchange Commission, or SEC.

	At December 31,		
	2004	2005	2006
Oil (Mmbbls)			
Developed	6.0	5.5	11.3
Undeveloped	1.2	1.3	4.9
Total	7.2	6.8	16.2
Natural gas (Bcf)			
Developed	319.5	321.7	665.3
Undeveloped	43.1	79.5	461.3
Total	362.6	401.2	1,126.6
Pre-tax present value, discounted at 10% (PV-10) (in millions)(1)			
Developed	$642.2	$1,046.7	$1,353.7
Undeveloped	58.2	201.9	252.3
Total	$700.4	$1,248.6	$1,606.0
Standardized Measure (in millions)	$473.7	$ 823.3	$1,311.8

(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.

	Spot price	
Date	Natural gas (per Mmbtu)	Oil (per Bbl)
December 31, 2004	$ 6.19	$43.33
December 31, 2005	10.08	61.03
December 31, 2006	5.64	60.82

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 because the tax characteristics of comparable companies can differ materially. 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, 2004	2005	2006
PV-10	$ 700.4	$ 1,248.6	$1,606.0
Future income taxes	(588.9)	(1,097.6)	(721.2)
Discount of future income taxes at 10% per annum	362.2	672.3	427.0
Standardized Measure	$ 473.7	$ 823.3	$1,311.8

The total reserve estimates presented as of December 31, 2004, 2005 and 2006 have been prepared by Lee Keeling and Associates, Inc., an independent petroleum engineering firm in Tulsa, Oklahoma. 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 and Associates, Inc. Estimates of oil and natural gas reserves are projections based on engineering data 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 22. 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.

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 Canada as a result of the sale of Addison in February 2005.

(in thousands, except production and per unit amounts)	Predecessor: Year ended December 31, 2004	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
Sales:				
Oil:				
Revenue(1)	$ 24,694	$ 19,528	$ 6,666	$ 57,043
Production sold (Mbbl)	638	375	116	916
Average sales price per Bbl(1)	$ 38.71	$ 52.07	$ 57.47	$ 62.27
Natural gas:				
Revenue(1)	$117,299	$113,293	$63,395	$298,737
Production sold (Mmcf)	19,220	15,490	5,112	44,123
Average sales price per Mcf(1)	$ 6.10	$ 7.31	$ 12.40	$ 6.77
Costs and expenses:				
Average production cost per Mcfe	$ 1.23	$ 1.25	$ 1.54	$ 1.39
General and administrative expense per Mcfe(2)	$ 0.67	$ 5.04	$ 1.10	$ 0.83
Depreciation, depletion and amortization per Mcfe	$ 1.24	$ 1.39	$ 2.42	$ 2.74

(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. See "—Significant transactions during 2005." 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.

Areas	At December 31, 2006 Gross wells(1) Oil	Gas	Total	Net wells Oil	Gas	Total
East Texas/North Louisiana	70	1,109	1,179	62.8	825.2	888.0
Appalachia	409	5,908	6,317	404.0	5,399.0	5,803.0
Mid-Continent	232	658	890	100.9	259.7	360.6
Permian	108	143	251	43.2	86.7	129.9
Rockies	114	178	292	56.5	147.3	203.8
Gulf Coast/Other	24	11	35	5.2	4.4	9.6
Total	957	8,007	8,964	672.6	6,722.3	7,394.9

(1) As of December 31, 2006, we owned interests in 38 gross wells with multiple completions.

As of December 31, 2006, we were the operator of 7,794 gross (7,012.1 net) wells, which represented approximately 90% of our Proved Reserves as of December 31, 2006.

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 Addison in February 2005. The information for the year ended December 31, 2005 is presented on an actual basis and therefore excludes TXOK's drilling activities.

	Development wells Gross Productive	Dry	Total	Net Productive	Dry	Total
Year ended December 31, 2004	91	2	93	85.4	1.3	86.7
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

	Exploratory wells Gross Productive	Dry	Total	Net Productive	Dry	Total
Year ended December 31, 2004	6	1	7	6.0	1.0	7.0
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

At December 31, 2006, we had 15 gross (10.1 net) wells being drilled and 18 gross (15.1 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 following table sets forth our developed and undeveloped acreage at December 31, 2006:

	At December 31, 2006			
	Developed acreage		Undeveloped acreage	
Areas	Gross	Net	Gross	Net
East Texas/North Louisiana	123,775	96,345	63,423	57,530
Appalachia	425,489	389,465	462,173	429,212
Mid-Continent	157,700	91,617	21,693	14,258
Permian	37,161	21,795	25,894	13,101
Rockies	47,344	29,622	143,524	128,198
Gulf Coast/Other	5,095	2,817	2,578	1,738
Total	796,564	631,661	719,285	644,037

The primary terms of our oil and natural gas leases expire at various dates, generally ranging from one to five years. Almost all 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 46,756, 60,730 and 36,426 net acres with leases expiring in 2007, 2008 and 2009, 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 regularly 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 operations for $443.4 million and the sale of our Wattenberg Field operations in Colorado for $131.9 million in January 2007. During the years ended December 31, 2004, 2005 and 2006, we received proceeds of $51.9 million, $45.3 million and $5.2 million, respectively, from the sale of properties in the United States.

Midstream operations

We own and operate a network of natural gas gathering systems comprised of approximately 500 miles of pipeline in our East Texas/North Louisiana area of operation, which gathers and transports natural gas to larger gathering systems and intrastate, interstate and local distribution pipelines owned by third parties. Of all the natural gas gathered and transported by this system, approximately 83% represents production from our assets and approximately 17% 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 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 December 2006, average throughput volume on the TGG Pipeline was 105 Mmcf/d with a total capacity of 175 Mmcf/d. Of all the natural gas transported by the TGG Pipeline, approximately 25% represents production from our assets and approximately 75% represents production from the assets of third parties.

Our principal customers

For the twelve months ended December 31, 2006, sales to one interstate pipeline company accounted for 11.6% of total oil and natural gas revenues. For the twelve months ended December 31, 2005 and 2004 sales to one industrial customer accounted for 10.1% and 10.6%, 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

U.S. regulations

The availability of a ready market for oil and natural gas production depends upon numerous factors beyond our control. These factors include state and federal regulation of oil and natural gas production and transportation, as well as regulations governing environmental quality and pollution control, state limits on allowable rates of production by a well or proration unit, the amount of oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be "shut-in" because of an over-supply of natural gas or lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of oil and natural gas, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and gas plants also are subject to the jurisdiction of various federal, state and local agencies.

FERC Matters

Our sales of natural gas are affected by the availability, terms and costs of transportation. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission, or FERC, under the Natural Gas Act, as well as under Section 311 of the Natural Gas Policy Act. 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. The FERC has announced several important transportation-related policy statements and rule changes, including a statement of policy and final rule issued February 25, 2000, concerning alternatives to its traditional cost-of-service rate-making methodology to establish the rates interstate natural gas pipelines may charge for their services. The final rule revises the FERC's pricing policy and current regulatory framework to improve the efficiency of the market and further enhance competition in natural gas markets.

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 may be subject to regulation by the Department of Transportation, or DOT, under the Hazardous Liquids Pipeline Safety Act of 1979, as amended, or the HLPSA. The HLPSA governs the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Where applicable, the HLPSA requires us and other pipeline operators to comply with regulations issued pursuant to HLPSA 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 amends the HLPSA in several important respects. The Pipeline Safety Act requires the Research and Special Programs Administration of DOT, or the RSPA, to consider environmental impacts, as well as its traditional public safety mandate, when developing pipeline safety regulations. In addition, the Pipeline Safety Act mandates the establishment by DOT of pipeline operator qualification rules requiring minimum training requirements for operators and requires that pipeline operators provide maps and records to RSPA. It also authorizes RSPA to require certain pipeline modifications as well as operational and maintenance changes. The Research and Special Program Improvements Act of 2004, or RSPIA, further amends the HLPSA, and transfers the authority of the RSPA to the newly-formed Pipeline and Hazardous Materials Safety Administration of DOT, or the PHMSA. In March 2006, the PHMSA issued a final rule regarding the definition of, and safety standards for, gas gathering pipelines, which establishes 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 this rule.

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, 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. 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 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, clean-up costs are usually allocated among various 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 and/or from conditions at third party disposal facilities where wastes from operations were sent.

Although CERCLA, as amended, 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 the exemption will be preserved in any future amendments of the act. Such amendments could have a significant 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 at a future date. 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 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. From time to time, proposals have been made that would reclassify certain oil and natural gas wastes, including wastes generated during pipeline, drilling and production operations, 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 significant 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. Federal and 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 such as permits by rule or general permits. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (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 some 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 create legal liabilities for 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 may impact agency permitting and review activities and add 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. 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.

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, 2006, we employed 471 persons of which 284 were involved in field operations and 187 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 contains forward-looking statements, as defined in Section 27A of the Securities Act of 1933, or 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, including, but not limited to:

- fluctuations in prices of oil and 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;
- 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;
- competition;
- title to our properties;
- litigation;
- 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 instrument contracts;
- hedging decisions, including whether or not to enter into 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; and
- 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. The risk factors noted in this annual report and other factors noted throughout this annual report 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.

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.

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

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.

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.

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, 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.

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.

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.

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

Available information

We make our filings with the SEC available on our website at *www.excoresources.com*.

ITEM 1A. RISK FACTORS

The risk factors noted in this section and other factors noted throughout this annual report, 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.

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, 2006, 92% 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.

Our revenues 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.

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. 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, and making it more difficult for us to pay dividends on our common stock. During the year ended December 31, 2005, we made cash settlement payments on our derivative financial instrument contracts totaling $85.0 million. During the year ended December 31, 2006, we received cash settlements from our counterparties totaling $29.4 million. For the year ended December 31, 2006, 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 $30.0 million. As of December 31, 2006, the net unrealized gains on our derivative financial instrument contracts was $96.4 million. The ultimate settlement amount of these unrealized derivative financial instrument contracts is dependent on future commodity prices. In connection with the acquisitions of TXOK and Winchester, we assumed additional derivative financial instruments that TXOK and Winchester had entered into covering a significant portion of their estimated future production. In connection with the pending acquisitions of the Vernon Assets and the Southern Gas Assets, we expect to assume additional derivative financial instruments from Anadarko 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—Our liquidity, capital resources and capital commitments—Derivative financial instruments."

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

The acquisitions of TXOK and Winchester represented a significant increase in our reserves and production. These acquisitions are the largest acquisitions that we have completed to date. As a result of the TXOK and Winchester acquisitions, as of December 31, 2006, we added 1,751 gross (1,042.7 net) wells to our consolidated portfolio of wells, including approximately 1,083 gross operated wells, which materially increased the number of wells we currently operate. If the pending acquisitions of the Vernon Assets for $1.6 billion in cash, subject to post-closing purchase price adjustments, and the Southern Gas Assets for $860.0 million in cash, subject to post-closing purchase price adjustments, are consummated, they will be significant acquisitions for us. We expect to add approximately 1,677 gross wells in connection with the pending acquisitions from Anadarko.

All of these factors present significant integration challenges for us. In addition to the other general acquisition risks described elsewhere in this section, the magnitude of theses 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 the acquisition of Winchester, 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.

Concurrent with the acquisition of Winchester, we contributed Winchester Acquisition to our wholly-owned subsidiary, EXCO Partners. In addition, we also contributed all of our East Texas oil and natural gas properties, related pipeline and gathering systems, compressors and other production related equipment, and contracts, including financial derivative instruments associated with our East Texas production, to EXCO Partners in exchange for a payment to us of $150.0 million in cash. To finance the acquisition and the $150.0 million payment to us for our East Texas assets, EXCO Partners' wholly-owned subsidiary, EPOP, entered into the EPOP Revolving Credit Facility. The initial amount borrowed under this facility was $651.0 million at closing of the acquisition of Winchester. As of December 31, 2006, $643.5 million was outstanding under the EPOP Revolving Credit Facility. In connection with the acquisition and our asset contribution, EPOP also entered into the EPOP Senior Term Credit Agreement. The aggregate principal amount of the Senior Term Credit Agreement is $650.0 million.

In connection with the arrangement of the Senior Term Credit Agreement, the lenders required us to enter into the Contribution Agreement. The Contribution Agreement generally provides that on the date 18 months from the Equity Contribution Date, we will make a cash common equity contribution to EPOP in an amount equal to the lesser of (i) $150.0 million or (ii) the aggregate amount then outstanding under the Senior Term Credit Agreement; provided, that in no event can this obligation exceed during the term of the Contribution Agreement the maximum amount that we could contribute under the terms of the Indenture governing our senior notes. Alternatively, we can cause EXCO Partners to make the equity contribution to EPOP in the amount of $150.0 million to satisfy this obligation. In lieu of requiring the equity contribution to be made, the lenders can elect at the Equity Contribution Date to require EPOP and its subsidiaries to become "Restricted Subsidiaries" under our credit agreement and require us to provide and cause all then Restricted Subsidiaries as defined and constituted under our credit agreement to provide guarantees and collateral in respect of the Senior Term Credit Agreement on terms substantially consistent with the guarantees and collateral provided under our credit agreement. This requirement is subject to compliance with our credit agreement. Any cash so contributed shall be used by EPOP to prepay loans under the Senior Term Credit Agreement. EXCO Resources and its subsidiaries are prohibited from making restricted payments (as defined in the Indenture) that would constitute a utilization of the Indenture restricted payment baskets, other than Restricted Payments not to exceed $5.0 million. In addition, we have covenanted to redeem or defease our senior notes if the Indenture would not permit the equity contribution or the lenders' election to cause us to designate EPOP and its subsidiaries as Restricted Subsidiaries under our credit agreement (subject to certain restrictions on the indebtedness that may be incurred for any such redemption or defeasance if the election to cause the designation of EPOP as a Restricted Subsidiary is chosen).

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: (1) the level of successful drilling activity near our gathering systems and (2) 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 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 Winchester's pipeline must be processed by processing plants before delivery into a pipeline for natural gas. Winchester does not own or control any of these processing plants. 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.

We expect to incur a substantial amount of indebtedness to fund the acquisitions of the Vernon Assets and the Southern Gas Assets, 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.

To finance the acquisitions of the Vernon Assets and the Southern Gas Assets, we received a Commitment Letter from J.P. Morgan Securities Inc. and JPMorgan Chase Bank, N.A., providing for a senior secured revolving credit facility commitment in the amount of $1.8 billion and an undertaking to arrange a bridge loan facility in the amount of $1.1 billion, if requested. If used to finance the acquisitions, the new credit facilities will contain customary representations, warranties and covenants, and the closing of the new credit facilities will be subject to the satisfaction of customary closing conditions. 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 the new credit facilities, which could cause us to default on our obligations and could impair our liquidity. We are also pursuing other financing alternatives.

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 agreement 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, 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 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 and Winchester 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 and Winchester acquisitions are subject to floors and caps 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. Because of our issuance of the senior notes and the pledge of substantially all of our assets as collateral under our credit agreements, it may be difficult for us in the foreseeable future to obtain 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 Equity Buyout and our IPO. 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 has substantially increased due to the TXOK and Winchester acquisitions and will further increase due to the pending acquisitions of the Vernon Assets and the Southern Gas Assets. 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.

We are not currently required to comply with Section 404 of the Sarbanes-Oxley Act of 2002, and are therefore 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.

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. Our management concluded that as of December 31, 2005, we did not maintain effective controls over the preparation and review of the quarterly and annual tax provision and the related financial statement presentation and disclosure of income tax matters. Specifically, our controls were not adequate to ensure the completeness and accuracy of the tax provision and the deferred tax balances, including the timing and classification of recording the tax impact of an extraordinary dividend. This control deficiency resulted in the restatement of our consolidated financial statements for the quarters ended June 30, 2005 and September 30, 2005 and audit adjustments to the consolidated financial statements for the years ended December 31, 2004 and 2005, affecting income tax expense and the deferred tax liability accounts. Additionally, this control deficiency could have resulted in a misstatement in the aforementioned tax accounts that would result in a material misstatement to the annual or interim financial statements that would not have been prevented or detected. Accordingly, management concluded that this deficiency in internal control over financial reporting was a material weakness. Although we believe we have taken the necessary steps to remediate this material weakness, as described in Item 9A of this Annual Report on Form 10-K, we may identify additional material weaknesses or other deficiencies in our internal control over financial reporting in the future.

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 when we are required to make an assessment of internal control over financial reporting under Section 404 for fiscal 2007.

Any material weaknesses or other deficiencies in our internal control over financial reporting may affect our ability to comply with SEC reporting requirements and New York Stock Exchange, or 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 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 2004, 2005 and 2006 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 and TXOK 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, 2006, third parties operate wells that represent approximately 10% 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 contains estimates of our proved oil and natural gas reserves and the PV-10 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 described in this annual report, and our financial condition. In addition, our reserves or PV-10 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. Any of these negative effects on our reserves or PV-10 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.

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 CEO.

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.

Depending upon oil and natural gas prices in the future, 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 writedowns 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, as defined, 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 temporary decline in revenues if we lose one of our significant customers.

For the year ended December 31, 2006, sales of natural gas to one interstate pipeline company accounted for 11.6% of our total oil and natural gas revenues. For the years ended December 31, 2005 and 2004, sales of natural gas to one industrial customer accounted for 10.1% and 10.6%, respectively, of our total oil and natural gas revenues. In 2006, our top eight customers accounted for approximately 38.2% 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 a temporary 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 are currently experiencing 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 the accounting and financial reporting, tax and land departments. 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.

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 March 1, 2007, we had approximately $2.1 billion of indebtedness, including $1.7 billion of indebtedness which is subject to variable interest rates. Our total interest expense on an annual basis would be approximately $180.0 million and would change by approximately $17.0 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 and the Indenture governing our senior notes 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 and our senior notes. A default, if not cured or waived, could result in acceleration of all indebtedness outstanding under our credit arrangements and our senior notes. 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. We amended certain financial covenants under the EPOP Revolving Credit Facility due to our inability to meet certain financial covenants associated with our EPOP Revolving Credit Facility (—See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, capital resources and commitments—EPOP Revolving Credit Facility.")

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.

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.

As of March 1, 2007, we had 104,221,015 shares of common stock outstanding. Of these shares, 70,628,370 shares are freely tradable, unless any of these shares are held by our affiliates.

Many of our shareholders, including our executive officers and directors, are subject to agreements that limit their ability to sell our common stock held by them. On October 3, 2005, we entered into a registration rights agreement with all of the holders of our common stock, which agreement was amended by the First Amended and Restated Registration Rights Agreement. A total of 50,388,889 shares of common stock were covered by this agreement. Any holder who is a party to this agreement has the right, commencing 180 days after completion of the IPO on February 14, 2006, to require us to register for resale up to one-third of their shares of common stock. All other parties to the registration rights agreement would then have the right to require us to register for resale up to one-third of their shares of common stock on the same registration statement. On January 17, 2007, our registration statement covering 16,796,244 shares was declared effective by the SEC.

The same rights exist commencing 365 days and 540 days after February 14, 2006 for an additional one-third of their shares at each such anniversary. These time and volume restrictions on resale registrations may be waived by J.P. Morgan Securities Inc. based on its evaluation of market and other conditions. On January 11, 2007, J.P. Morgan Securities Inc. and EXCO executed a waiver letter that allows selling shareholders to request that we register for resale the remaining two-thirds of their shares at any time after February 14, 2007. On February 15, 2007, we received a request from one of our shareholders to register the remaining two-thirds of his shares in accordance with the registration rights agreement. We expect to register 33,592,645 shares, the remaining two-thirds of the shares subject to the registration rights agreement, as soon as practicable after the filing of this annual report. In addition, at any time that we file a registration statement registering other shares, the holders of shares subject to the registration rights agreement can require that we include their shares in such registration statement, subject to certain exceptions. The filing of any resale registration statement and the sale of shares thereunder may have a material adverse effect on the market price of our common 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. We are considering the issuance of up to $2.0 billion of preferred stock to institutional accredited investors in a private placement under the Securities Act of 1933. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity, capital resources and capital commitments—Proposed recapitalization." We have not entered into definitive agreements with potential investors to issue any preferred stock. As a result, we may never issue any preferred stock. In addition, any preferred stock that we ultimately issue may contain terms different from those provided in this annual report.

We have not paid dividends in the past and do not expect to pay dividends in the future, and any return on investment may be limited to the value of our stock.

We have never paid cash dividends on our common stock and do not anticipate paying cash dividends on our common stock in the foreseeable future. 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 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 the payment of dividends.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Corporate offices

We lease approximately 33,500 square feet of office space in Dallas, Texas, for our corporate offices. On February 27, 2006 we amended this lease effective July 1, 2006 to obtain additional square footage and extend the expiration date from June 30, 2011 to June 30, 2013. The lease requires monthly rental payments of approximately $48,300. We lease an office in Akron, Ohio. The Akron office contains approximately 17,000 square feet and requires monthly rental payments of approximately $23,700. The Akron office lease expires December 15, 2012. TXOK has entered into a lease agreement effective March 1, 2006, for approximately 22,700 square feet of office space in Tulsa, Oklahoma. The lease expires May 31, 2011, and requires monthly rental payments of approximately $24,500. We lease 15,246 square feet of office space in Shreveport, Louisiana. The lease expires September 30, 2008. This lease requires monthly rental payments of approximately $12,100 per month. We also have small offices for technical and field operations in Texas, Oklahoma, Colorado, Nebraska, Ohio and West Virginia.

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" beginning on page 1 of this annual report.

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. 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 and claims. We do not believe that any resulting liability from existing legal proceedings, individually or in the aggregate, will have a materially adverse effect on our results of operations or financial condition.

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

None.

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, 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
Year ended December 31, 2005:		
First Quarter	N/A	N/A
Second Quarter	N/A	N/A
Third Quarter	N/A	N/A
Fourth Quarter	N/A	N/A

Our shareholders

According to our transfer agent, Continental Stock Transfer & Trust Company, there were approximately 147 holders of record of our common stock on March 1, 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, and do not anticipate paying cash dividends on our common stock in the foreseeable future. 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 our "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. This information does not replace the consolidated financial statements. We have completed numerous acquisitions and dispositions since 2002 that materially impact the comparability of this data between periods.

The selected financial data for the twelve months ended December 31, 2002 and 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, 2006 is referred to as successor.

(in thousands, except per share amounts)	Public predecessor 2002	Public predecessor 209 day period from January 1 to July 28, 2003	Predecessor 156 day period from July 29 to December 31, 2003
Statement of operations data(1):			
Revenues and other income:			
Oil and natural gas	$ 34,287	$ 22,403	$ 21,767
Derivative financial instruments(2)	—	—	(10,800)
Other	6,599	(1,129)	(141)
Total revenues and other income	40,886	21,274	10,826
Costs and expenses:			
Oil and natural gas production	19,018	11,380	7,331
Depreciation, depletion and amortization	9,031	5,125	5,413
Accretion of discount on asset retirement obligations(3)	—	320	205
General and administrative	6,777	11,347	3,874
Interest expense	1,191	1,058	1,921
Impairment of marketable securities	1,136	—	—
Total costs and expenses	37,153	29,230	18,744
Income (loss) before income taxes	3,733	(7,956)	(7,918)
Income tax benefit	(2,672)	(181)	(7,764)
Income (loss) before discontinued operations and change in accounting principle	6,405	(7,775)	(154)
Discontinued operations:			
Income (loss) from operations	(11,382)	13,534	6,217
Gain on disposition of Addison Energy Inc.	—	—	—
Income tax expense (benefit)	(4,010)	4,982	1,917
Income (loss) from discontinued operations:	(7,372)	8,552	4,300
Income (loss) before change in accounting principle	(967)	777	4,146
Cumulative effect of change in accounting principle, net of income tax	—	255	—
Net income (loss)	(967)	1,032	4,146
Dividends on preferred stock	5,256	2,620	—
Earnings (loss) on common stock	$ (6,223)	$ (1,588)	$ 4,146
Basic earnings (loss) per share from continuing operations	$ 0.16	$ (1.25)	$ —
Basic loss per share—total	$ (0.88)	$ (0.19)	$ 0.04
Diluted earnings (loss) per share from continuing operations	$ 0.16	$ (1.25)	$ —
Diluted income (loss) per share—total	$ (0.88)	$ (0.19)	$ 0.04
Weighted average common and common equivalent shares outstanding:			
Basic	7,061	8,084	115,947
Diluted	12,533	8,084	115,947
Statement of cash flow data:(2)			
Net cash provided by (used in):			
Operating activities	$ 31,660	$ 20,418	$ 21,495
Investing activities	(76,937)	(23,520)	(237,623)
Financing activities	45,928	9,982	214,284
Balance sheet data:(2)			
Current assets	$ 26,198	n/a	$ 31,641
Total assets	241,174	n/a	505,056
Current liabilities	33,193	n/a	45,188
Long-term debt, less current maturities	97,943	n/a	—
Shareholders' equity	99,894	n/a	183,895
Total liabilities and shareholders' equity	241,174	n/a	505,056

Selected consolidated financial and operating data (continued)

(in thousands, except per share amounts)	Predecessor 2004	Predecessor 275 day period from January 1 to October 2, 2005	Successor 90 day period from October 3 to December 31, 2005	Successor 2006
Statement of operations data(1):				
Revenues and other income:				
Oil and natural gas	$ 141,993	$ 132,821	$ 70,061	$ 355,780
Derivative financial instruments(2)	(50,343)	(177,253)	(256)	198,664
Other	1,184	7,096	2,374	5,005
Total revenues and other income	92,834	(37,336)	72,179	559,449
Costs and expenses:				
Oil and natural gas production	28,256	22,157	8,949	68,874
Depreciation, depletion and amortization	28,519	24,687	14,071	135,722
Accretion of discount on asset retirement obligations(3)	800	617	226	2,014
General and administrative(4)	15,466	89,442	6,375	41,206
Interest expense	34,570	26,675	19,414	84,871
Total costs and expenses	107,611	163,578	49,035	332,687
Equity in net income of TXOK Acquisition, Inc.	—	—	837	1,593
Income (loss) before income taxes	(14,777)	(200,914)	23,981	228,355
Income tax expense (benefit)	5,126	(63,698)	7,631	89,401
Income (loss) before discontinued operations	(19,903)	(137,216)	16,350	138,954
Discontinued operations:				
Income (loss) from operations	36,274	(4,403)	—	—
Gain on disposition of Addison Energy Inc.	—	175,717	—	—
Income tax expense	10,358	49,282	—	—
Income from discontinued operations:	25,916	122,032	—	—
Net income (loss)	$ 6,013	$ (15,184)	$ 16,350	$ 138,954
Basic earnings (loss) per share from continuing operations	$ (0.17)	$ (1.18)	$ 0.35	$ 1.44
Basic earnings (loss) per share—total	$ 0.05	$ (0.13)	$ 0.35	$ 1.44
Diluted earnings (loss) per share from continuing operations	$ (0.17)	$ (1.18)	$ 0.35	$ 1.41
Diluted earnings (loss) per share—total	$ 0.05	$ (0.13)	$ 0.35	$ 1.41
Weighted average common and common equivalent shares outstanding:				
Basic	115,947	116,504	47,222	96,727
Diluted	115,947	116,504	47,222	98,453
Statement of cash flow data:(2)				
Net cash provided by (used in):				
Operating activities	$ 118,528	$ (81,122)	$ 8,177	$ 227,659
Investing activities	(381,476)	337,880	(13,337)	(1,791,517)
Financing activities	283,708	(47,035)	(4,018)	1,359,727
Balance sheet data:(2)				
Current assets	$ 75,877	n/a	$ 342,525	$ 236,710
Total assets	922,052	n/a	1,530,493	3,707,057
Current liabilities	105,695	n/a	465,725	190,924
Long-term debt, less current maturities	487,453	n/a	461,802	2,081,653
Shareholders' equity	203,885	n/a	370,882	1,179,850
Total liabilities and shareholders' equity	922,052	n/a	1,530,493	3,707,057

(1) We have completed numerous acquisitions and dispositions since January 1, 2002 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.

(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" on October 3, 2005. Share-based compensation pursuant to SFAS No. 123(R) included in general and administrative expenses is $3.0 million and $6.5 million for the 90 day period from October 3, 2005 to December 31, 2005 and the twelve months ended December 21, 2006, respectively. See "Note 2. Summary of significant accounting policies—stock options" in the notes to our consolidated financial statements included in this annual report.

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. 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.

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 investment, and manage our capital structure. On February 14, 2006, we acquired TXOK for approximately $665.1 million and on October 2, 2006, we completed the acquisition of Winchester for approximately $1.1 billion in cash after closing adjustments. The Winchester acquisition was completed within our newly-formed subsidiary, EXCO Partners. Concurrent with the closing of this acquisition we contributed to EXCO Partners all of our East Texas assets, including four of our subsidiaries that own or operate certain of our East Texas assets, in exchange for $150.0 million of cash and additional equity interests in EXCO Partners. EPOP borrowed $1.3 billion to fund these transactions. Our 2006 acquisitions, including TXOK and Winchester, totaled in excess of $2.1 billion. In addition, we spent $214.3 million for development drilling, acreage and related oil and natural gas facilities during 2006. For a discussion of these acquisitions as well as other transactions that we completed during 2005 and 2006, see "Item 1. Business—Significant transactions during 2005" and "Item 1. Business—Significant transactions during 2006." We expect that our pending acquisitions with Anadarko will have a significant impact on our results of operations, liquidity and financial condition during 2007. For a discussion of these pending acquisitions, see "Item 1. Business—Significant subsequent events."

Oil and natural gas prices have historically been volatile. During 2006, the NYMEX price for natural gas has fluctuated from a high of $10.63 per Mmbtu to a low of $4.20 per Mmbtu. On December 31, 2006, the spot market price for natural gas at Henry Hub was $5.64 per Mmbtu, a 45% decrease from December 31, 2005. The price of oil has shown similar volatility. In 2006, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were $62.27 per Bbl and $6.77 per Mcf compared with 2005 prices of $53.35 per Bbl and $8.58, respectively. The volatile commodity price environment from 2004 through 2006, 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 did not encounter any significant operational problems or operational delays as a result of these scheduling difficulties. We cannot predict the impact that the recent declines 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 develop and identify 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 IPO in February 2006, we amended our revolving credit agreement with our banking syndicate which provided for a borrowing base of $750.0 million with an aggregate commitment of $500.0 million. As a result of the acquisition of Winchester on October 2, 2006, and the contribution of our East Texas assets to EXCO Partners, our credit agreement was further amended to reflect the contribution of these assets by reducing the borrowing base to $600.0 million with a $500.0 million aggregate commitment. EPOP has a separate $750.0 million credit agreement with a $650.0 conforming borrowing base and $650.0 million term loan which was used to finance the acquisition of Winchester. 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, derivatives accounting, 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 accounting principles that are generally accepted in the United States, or 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. Upon closing of the Equity Buyout, we adopted SFAS No. 123(R), "Share-Based Payment," or SFAS No. 123(R). 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 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 is 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, a 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 for impairment.

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 (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 and natural gas, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil and natural gas, that may occur in undrilled prospects; and (D) 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 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

Prior to October 3, 2005, we accounted for share-based payments to employees using the intrinsic value method prescribed by APB No. 25, "Accounting for Stock Issued to Employees" and related interpretations. As such, we did not recognize compensation expense associated with employee stock options, as the options were granted at fair market value on the date of grant. Holdings II adopted the provisions of SFAS No. 123(R) upon its formation in August 2005. Upon closing of the Equity Buyout, we adopted SFAS No. 123(R). At December 31, 2006, our employees and directors held options under EXCO's 2005 Long-Term Incentive Plan, or the 2005 Incentive Plan, to purchase 8,267,373 shares of EXCO common stock at prices ranging from $7.50 per share to $14.62 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 $5.01 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 2006 was $7.9 million, of which $1.4 million was capitalized to the full cost pool. In 2005, a total of $3.2 million of share-based compensation was incurred, of which $1.0 million was capitalized to the full cost pool.

For the 275 day period ended October 2, 2005, a non-recurring $44.1 million share-based compensation expense was recognized as a result of the Equity Buyout. This compensation charge was attributable to the Class B common shares of EXCO Holdings purchased by Holdings II.

Accounting for oil and natural gas properties

The accounting for, and disclosure of, oil and natural gas producing activities requires that we choose between GAAP alternatives and that we make judgments regarding estimates of future uncertainties.

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 full cost pool or in *unevaluated properties*. Unevaluated property costs are not subject to depletion. We review our unevaluated oil and natural gas property costs on an ongoing basis, and we expect these costs to be evaluated in one to five years and transferred to 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 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 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 the Canadian full cost pools. When computing our full cost ceiling limitation, 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 February 2007, we sought, and received an exemption from the SEC to exclude our 2006 acquisitions of oil and natural gas properties from our ceiling test for a period of 12 months, provided that we could demonstrate beyond a reasonable doubt that the fair value of the oil and natural gas reserves acquired in 2006 exceeded their unamortized carrying costs. Assuming we can demonstrate the fair value exceeds the carrying costs for the next 12 months, we will initially test the 2006 acquisitions at December 31, 2007.

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.

In September 2004, the SEC released SAB No. 106 concerning the application of SFAS No. 143 "Accounting for Asset Retirement Obligations," or SFAS No. 143, by oil and natural gas producing companies following the full cost method of accounting. In SAB No. 106, the SEC addressed the impact of SFAS No. 143 on the ceiling test calculation and on the calculation of depreciation, depletion and amortization. SAB No. 106 became effective for us on January 1, 2005 and has not had a significant impact on our ceiling test calculation. Also, as a result of SAB No. 106, we now include the estimated asset retirement obligation that will result from future development activity in our calculation of depreciation, depletion and amortization. This change has not had a significant impact on our depreciation, depletion and amortization expense.

Prior to the issuance of SFAS No. 143, we included expected future cash flows related to the asset retirement obligations from certain properties in our ceiling test calculation. Under SFAS No. 143, we must now initially capitalize asset retirement costs by increasing long-lived oil and natural gas assets by the same amount as the asset retirement liability before discount. After adoption of SFAS No. 143, if we were to continue to calculate the full cost ceiling test by reducing expected future net revenues by the cash flows required to settle the asset obligation, then the effect would be to "double-count" such costs in the ceiling test.

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 in 2006 of $64.9 million, $21.2 million and $163.9 million was recognized from the acquisitions of TXOK, PGMT and Winchester, respectively. As of December 31, 2006, 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, 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

In June 2001, the Financial Accounting Standards Board, or FASB, issued 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. We adopted SFAS No. 143 on January 1, 2003. The costs of plugging and abandoning oil and natural gas properties fluctuate with costs associated with the industry. Recent cost increases have impacted our evaluation of asset retirement obligations. 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. As a result of the Equity Buyout, our book basis of assets increased by approximately $380.3 million, while our tax basis carried over. The result was an increase to our deferred tax liability. Deferred taxes are recorded to reflect the tax benefit 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. Prior to the planned disposition of Addison, we considered Addison's earnings to be permanently reinvested for use in those operations and, consequently, deferred federal income taxes, net of applicable foreign tax credits, had not been provided on the undistributed earnings of Addison that were reinvested. As a result of the sale of Addison, we provided for deferred federal income taxes in the fourth quarter of 2004 on the undistributed earnings of Addison which is reflected as income tax expense of discontinued operations.

Recent accounting pronouncements

In July 2006, the 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 SFAS No. 109, "Accounting for Income Taxes." FIN 48 provides guidance on recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions that a company has taken or expects to take on a tax return. FIN 48 is effective as of January 1, 2007. The adoption of FIN 48 did not have a material impact on our financial statements.

In September 2006, the SEC Staff issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," or SAB 108, in an effort to address diversity in the accounting practice of quantifying misstatements and the potential for improper amounts on the balance sheet. Prior to the issuance of SAB 108, the two methods used for quantifying the effects of financial statement errors were the "roll-over" and "iron curtain" methods. Under the "roll-over" method, the primary focus is the income statement, including the reversing effect of prior year misstatements. The criticism of this method is that misstatements can accumulate on the balance sheet. On the other hand, the "iron curtain" method focuses on the effect of correcting the ending balance sheet, with less importance on the reversing effects of prior year errors in the income statement. SAB 108 establishes a "dual approach" which requires the quantification of the effect of financial statement errors on each financial statement, as well as related disclosures. Public companies are required to record the cumulative effect of initially adopting the "dual approach" method in the first year ending after November 16, 2006 by recording any necessary corrections to asset and liability balances with an offsetting adjustment to the opening balance of retained earnings. The use of this cumulative effect transition method also requires detailed disclosures of the nature and amount of each error being corrected and how and when they arose. We adopted SAB 108 in the fourth quarter of 2006. The adoption of SAB 108 did not have a material impact on our financial statements.

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. We will be required to adopt SFAS No. 157 in the first quarter of fiscal year 2008. We are currently evaluating the impact of SFAS No. 157 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 2004, 2005 and 2006 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 measurements for 2005, discussed below, provide a more meaningful basis for comparing our results of operations. A summary of key financial data for 2004, 2005 and 2006 related to our results of operations for the years then ended is presented below.

	Predecessor		Successor				
(dollars in thousands)	Year ended December 31, 2004	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	Successor Year ended December 31, 2006	Year to year change(b) 2004 - 2005	2005 - 2006
Production:							
Oil (Mbbls))	638	375	116	491	916	(147)	425
Natural gas (Mmcf)(a)	19,220	15,490	5,112	20,602	44,123	1,382	23,521
Total production (Mmcfe)	23,048	17,740	5,808	23,548	49,619	500	26,071
Oil and natural gas revenues before derivative financial instrument activities:							
Oil revenues	$ 24,694	$ 19,528	$ 6,666	$ 26,194	$ 57,043	$ 1,500	$ 30,849
Natural gas sales(a)	117,299	113,293	63,395	176,688	298,737	59,389	122,049
Total oil and gas sales	$141,993	$ 132,821	$ 70,061	$ 202,882	$355,780	$ 60,889	$152,898
Derivative financial instruments:							
Cash settlements on derivative financial instruments	$ (26,083)	$ (62,842)	$ (22,210)	$ (85,052)	$ 29,423	$ (58,969)	$114,475
Non-cash change in fair value of derivative financial instruments	(24,260)	(114,411)	21,954	(92,457)	169,241	(68,197)	261,698
Total derivative financial instruments management activities	$ (50,343)	$(177,253)	$ (256)	$(177,509)	$198,664	$(127,166)	$376,173
Average sales price (before cash settlements of derivative financial instruments):							
Oil (Bbl)	$ 38.71	$ 52.07	$ 57.47	$ 53.35	$ 62.27	$ 14.64	$ 8.92
Natural gas (per Mcf)	6.10	7.31	12.40	8.58	6.77	2.48	(1.81)
Natural gas equivalent (per Mcfe)	6.16	7.49	12.06	8.62	7.17	2.46	(1.45)
Oil and natural gas production costs:							
Oil and natural gas operating costs	$ 19,834	$ 14,581	$ 5,485	$ 20,066	$ 46,534	$ 232	$ 26,468
Production and ad valorem taxes	8,422	7,576	3,464	11,040	22,340	2,618	11,300
Depreciation, depletion and amortization	28,519	24,687	14,071	38,758	135,722	10,239	96,964
General and administrative	15,466	89,442	6,375	95,817	41,206	80,351	(54,611)
Interest expense	34,570	26,675	19,414	46,089	84,871	11,519	38,782
Expenses (per Mcfe):							
Operating costs	0.86	0.82	0.94	0.85	0.94	$ (0.01)	$ 0.09
Production and ad valorem taxes	0.37	0.43	0.60	0.47	0.45	0.10	(0.02)
Depreciation, depletion and amortization	1.24	1.39	2.42	1.65	2.74	0.41	1.09
General and administrative	0.67	5.04	1.10	4.07	0.83	3.40	(3.24)
Income (loss) from continuing operations	$ (19,903)	$(137,216)	$ 16,350	$(120,866)	$138,954	$(100,963)	$259,820

(a) Natural gas production and sales include volumes and values previously reported as natural gas liquids for 2004, 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.

The following is a discussion of our financial condition and results of operations for the years ended December 31, 2004, 2005 and 2006. 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 2004, 2005 and 2006 is impacted by:

- the acquisition of North Coast on January 27, 2004;
- property acquisitions and dispositions, including the sale of Addison on February 10, 2005;
- significant changes in the amount of our long-term debt including the issuance of our senior notes on January 20, 2004 in the amount of $350.0 million and on April 13, 2004 in the amount of $103.3 million (including applicable premium);
- significant fluctuations in oil and 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; and
- the incurrence of $1.3 billion of debt incurred to finance the Winchester acquisition.

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. With the exception of our Black Lake Field in Louisiana, which we sold in November 2004, we do not process a significant portion of the natural gas or NGLs we produce. At the Black Lake Field, we operated a natural gas processing plant that was 100% dedicated to production from the field.

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 natural gas for other producers for which we are compensated.

During the year ended December 31, 2004, an industrial purchaser, Alliance Energy Services L.L.C., or Alliance, accounted for 10.6% of our total oil and natural gas revenues. Under our end user contract in 2004 with Alliance, the purchaser was obligated to take all of the natural gas we could produce from a specified gathering system of ours up to 10,000 gross Mmbtu per day (which includes natural gas of other interest owners in the affected wells). We were obligated to use commercially reasonable efforts to supply that volume of natural gas from our wells connected to the gathering system subject to production declines experienced by the affected wells. The sales were priced monthly at the Columbia Gas Transmission Corp. Appalachia Index plus a specified premium. Our revenues under this contract in 2004 aggregated $14.7 million. This contract was replaced with a contract with the actual end user, Alcan Rolled Products-Ravenswood, LLC, beginning January 1, 2005 through December 31, 2007. Under the new contract the end user will purchase all of the natural gas we can produce, subject to well production declines, from the specified gathering system up to 10,000 gross Mmbtu per day (which includes natural gas of other interest owners in the affected wells). The contract price is the monthly Columbia Gas Transmission Corp. Appalachia Index plus a specified premium. Our revenues under this contract in 2005 and 2006 aggregated $20.6 million and $17.5 million, respectively, or 10.1% and 4.9%, respectively, of our total oil and natural gas revenues. During 2006, oil and natural gas sales to Duke Energy and its affiliates totaled 11.6% of our total oil and natural gas revenues.

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 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, 2006, we had income from continuing operations of $139.0 million on consolidated revenues (before impacts of derivative financial instruments) of $355.8 million compared with a net loss from continuing operations of $120.9 million on consolidated revenues of $202.9 million for the non-GAAP combined 2005 period (before impacts of derivative financial instruments). Net income for the 2005 non-GAAP combined period was $1.2 million which reflects a $122.0 million gain from the sale of Addison in February 2005. For the year ended December 31, 2004, net income was $6.0 million on consolidated revenues (before impacts of derivative financial instruments) of $142.0 million. The impact of acquisitions and derivative financial instruments are significant to our results of operations. During 2006, we closed over $1.8 billion of acquisitions of oil and natural gas properties which significantly increased our revenues and related 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 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 2004, 2005 and 2006, the impacts of derivative financial instruments, including the mark-to-market impacts, totaled losses of $50.3 million and $177.5 million for 2004 and non-GAAP combined 2005, respectively, while 2006 activities resulted in derivative gains of $198.7 million, of which $169.2 million is unrealized.

Oil and natural gas sales, production and prices

Total oil and natural gas sales, excluding the impact of derivative financial instruments, for 2006 were $355.8 million compared with $202.9 million for non-GAAP combined 2005 and $142.0 million in 2004. For 2006, natural gas represented 84.0% of our revenues and 88.9% of equivalent production. Both 2005 and 2004 also have natural gas percentages in excess of 80.0% of total revenues and total production. Our equivalent sold production volumes for 2006 were 49.6 Bcfe compared with 23.5 Bcfe for non-GAAP combined 2005, an increase of 111.1%. Equivalent production from our 2006 acquisitions represented over 50% of 2006 total volumes. Sold production volumes for 2004 were 23.0 Bcfe, 2.1% less than non-GAAP combined 2005. The average price per Mcfe, before the impact of derivative financial instruments, was $7.17, $8.62 and $6.16 for 2006, non-GAAP combined 2005 and 2004, respectively.

For 2006, our average price received for natural gas, excluding the impact of derivative financial instruments, was $6.77 per Mcf compared with $8.58 per Mcf in non-GAAP combined 2005 and $6.10 in 2004. The average price received for oil, also excluding the impacts of derivative financial instruments was $62.27 per Bbl, or 16.7% higher than the non-GAAP combined 2005 price of $53.35 per Bbl. The average price per Bbl for 2004 was $38.71. 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 gas in storage, weather and other seasonal condition, 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 and related liquidity. Assuming our December 2006 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 $6.5 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 $1.2 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 2006, our revenues (before the impact of derivative financial instruments) increased to $355.8 million from $202.9 million for non-GAAP combined 2005. The total increase of $152.9 million was attributable to an increase of $185.9 million from increased volumes primarily due to 2006 acquisitions. This increase was partially offset by a reduction in our realized price per Mcfe, which lowered revenue by $33.0 million.

During 2006, our acquisitions were focused on East Texas/North Louisiana and Appalachia regions of the United States. TXOK also significantly increased our presence in the Mid-Continent region. Following is a summary of production grouped by our significant producing regions for the years ended December 31, 2004, non-GAAP combined 2005 and 2006.

	Years ended December 31,					
	2004		Non-GAAP 2005		2006	
Areas	Mmcfe	%	Mmcfe	%	Mmcfe	%
East Texas/North Louisiana	813	3.5	2,894	12.3	17,423	35.1
Appalachia	11,105	48.2	12,892	54.7	15,028	30.3
Mid-Continent	1,288	5.6	994	4.2	9,494	19.1
Permian	3,821	16.6	3,591	15.2	4,725	9.5
Rockies	2,662	11.5	2,553	10.8	2,484	5.0
Gulf Coast and other	3,359	14.6	624	2.6	465	0.9
Total production	23,048	100.0	23,548	100.0	49,619	100.0

In January 2007, we completed the sale of our producing properties and remaining undeveloped drilling locations in the Wattenberg Field area of the DJ Basin, Colorado. This transaction included substantially all of our assets in the Rockies area. If the pending acquisitions of the Vernon Assets and the Southern Gas Assets are consummated, we expect to significantly increase 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 derivative financial instrument activities and components of other income. 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. As a result of the pending acquisitions from Anadarko, we will assume additional derivative financial instruments covering a substantial portion of the acquired production.

	Predecessor		Successor		Successor		
(in thousands)	Year ended December 31, 2004	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 to year change 2004-2005(a)	Year to year change 2005-2006(a)
Derivative financial instrument activities:							
Cash settlements on derivative financial instruments	$(26,083)	$ (62,842)	$(22,210)	$ (85,052)	$ 29,423	$ (58,969)	$114,475
Non-cash change in fair value ofderivative financial instruments	(24,260)	(114,411)	21,954	(92,457)	169,241	(68,197)	261,698
Total derivative financial instrument activities	$(50,343)	$(177,253)	$ (256)	$(177,509)	$198,664	$(127,166)	$376,173

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

Our cash settlements for 2006 increased revenue by $29.4 million compared with cash payments of $85.1 million for non-GAAP combined 2005. The cash payments in 2005 reduced revenue while the 2006 cash receipts increased revenue. The NYMEX oil and natural gas prices that we used to settle our derivative financial instruments varied significantly during 2005 and 2006. In 2005, the impacts of hurricanes caused natural gas prices to reach record highs which resulted in us making significant payments to our counterparties. Cash payments for the non-GAAP combined 2005 period includes payments totaling $52.6 million made in January and March 2005 to counterparties to terminate existing derivative contracts and enter into new derivative contracts at higher underlying product prices.

Our mark-to-market non-cash changes in the value of derivative financial instruments for 2006 resulted in a gain of $169.2 million compared with a $92.5 million loss 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.

As of December 31, 2006, we had derivative financial instruments, excluding the pending acquisitions from Anadarko, in place hedging approximately 79% of our expected 2007 oil production and approximately 83% of our expected 2007 natural gas production . These levels are consistent with our acquisition and financing strategy and average historical levels of hedged production.

Oil and natural gas operating costs

Operating costs, which include labor, materials and supplies necessary to produce our oil and natural gas were $46.5 million, or $0.94 per Mcfe for 2006, compared with $20.1 million, or $0.85 per Mcfe for non-GAAP combined 2005. The increase of $26.5 million is due primarily to $21.9 million of costs associated with the 2006 acquisitions, including TXOK, PGMT and Winchester. The per unit increase in cost reflects a general increase in the cost of goods and services for all of our producing areas.

Operating costs for 2004 were $19.8 million, or $0.86 per Mcfe, compared with $20.1 million, or $0.85 per Mcfe, for non-GAAP 2005. Operating costs per unit outside of our Appalachia area decreased to $0.89 per Mcfe in non-GAAP combined 2005 from $0.97 in 2004. This decrease was due primarily to sales of producing properties in 2004 which had higher operating costs. Per unit costs in our Appalachia region increased to $0.82 per Mcfe in non-GAAP combined 2005 from $0.74 in 2004 due primarily to higher personnel related costs and increased costs of goods and services used in the operations.

Production and ad valorem taxes

Production and ad valorem taxes were $22.3 million, $11.0 million and $8.4 million for 2006, non-GAAP combined 2005 and 2004, respectively. Production taxes are set by state and local governments and vary as to the tax rate and the value to which the rate is applied. Further, ad valorem taxes in Texas, where a substantial amount of our oil and natural gas is produced, are based partially on the value of oil and natural gas reserves, which can fluctuate significantly depending on prices for these products. On a percentage of sales basis, our 2006 production and ad valorem taxes were 6.3% of oil and natural gas sales, excluding the impact of derivative financial instruments compared with 5.4% for non-GAAP combined 2005 and 5.9% in 2004. 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 higher combined production and ad valorem tax rates than our Appalachia producing area.

Depreciation, depletion and amortization

The following table presents our depreciation, depletion and amortization expenses for 2004, 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 and 2006. The depreciation, depletion and amortization rate per Mcfe produced varies significantly for each of the periods presented due to the Equity Buyout on October 3, 2005 which resulted in a new stepped-up basis of accounting, which increased the calculated rate per Mcfe from $1.65 per Mcfe to $2.42 per Mcfe for the 90 day period from October 3, 2005 to December 31, 2005. During 2006, our acquisition of TXOK, PGMT and Winchester further increased the depreciation, depletion and amortization rate to $2.74 per Mcfe in 2006.

	Predecessor		Successor		Successor		
(in thousands)	Year ended December 31, 2004	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 to year change 2004-2005(a)	Year to year change 2005-2006(a)
Depreciation, depletion and amortization costs:							
Depreciation, depletion and amortization expense	$28,519	$24,687	$14,071	$38,758	$135,722	$10,239	$96,964
Mmcfe produced	23,048	17,740	5,808	23,548	49,619	500	26,071
Calculated rate per Mmcfe	$ 1.24	$ 1.39	$ 2.42	$ 1.65	$ 2.74	$ 0.41	$ 1.09

(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 $2.0 million in 2006 from $0.8 million each in non-GAAP combined 2005 and the year ended December 31, 2004. The increase in 2006 is due to the combination of significant well additions and related plugging liabilities in connection with our 2006 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 year ended December 31, 2004, 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 and the year ended December 31, 2006 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.

	Predecessor		Successor				
(in thousands except per unit amounts)	Year ended December 31, 2004	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	Successor Year ended December 31, 2006	Year to year change 2004-2005(a)	Year to year change 2005-2006(a)
General and administrative costs:							
Gross general and administrative expense	$19,157	$18,220	$7,329	$25,549	$52,357	$ 6,392	$ 26,808
Operator overhead reimbursements	(2,109)	(1,291)	(532)	(1,823)	(7,824)	286	(6,001)
Nonrecurring bonus expense from equity buyout	—	29,624	—	29,624	—	29,624	(29,624)
Equity buyout non cash-stock based compensation	—	44,092	—	44,092	—	44,092	(44,092)
Capitalized acquisition, development and exploitation charges	(1,582)	(1,203)	(422)	(1,625)	(3,327)	(43)	(1,702)
Net general and administrative expense	$15,466	$89,442	$6,375	$95,817	$41,206	$80,351	$(54,611)
General and administrative expense per Mcfe	$ 0.67	$ 5.04	$ 1.10	$ 4.07	$ 0.83	$ 3.40	$ (3.24)

(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, 2006 were $41.2 million compared with $95.8 million in non-GAAP combined 2005, a decrease of $54.6 million. Each of the respective years contains significant and notable variances. In 2006, we experienced significant increases in personnel and related support facilities. These increased personnel related expenses totaled approximately $7.2 million of increased cash expenses and increases of approximately $4.3 million from share-based compensation. We also incurred approximately $9.2 million of legal and project-oriented costs including (i) audit and legal fees in connection with our 2006 acquisitions, (ii) fees associated with services related to the formation of EXCO Partners, (iii) costs for implementation and compliance with Section 404 of the Sarbanes-Oxley Act of 2002 and (iv) expenses incurred for conversion of our information technology systems to a common platform. General and administrative costs for 2005 included non-recurring costs of $73.7 million ($44.1 million of which was non-cash stock compensation) related to the Equity Buyout.

When comparing non-GAAP combined 2005 general and administrative costs to the year ended December 31, 2004, the most significant variances are related to the non-recurring costs related to the Equity Buyout in 2005 of $73.7 million. Other significant increases between the periods included increased costs in 2005 for share-based compensation resulting from the adoption of SFAS No. 123R in October 2005, increased personnel costs and higher legal and accounting expenses for the analysis of strategic alternatives considered in light of the sale of Addison.

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 IPO, Holdings merged with us and we assumed the EXCO Holdings 2005 Long-Term Incentive Plan, or the 2005 Long-Term Incentive Plan.

During 2006, we issued options to purchase approximately 3.6 million shares of common stock under our 2005 Long-Term Incentive Plan 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 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 shareholder's equity as additional paid-in capital.

Interest expense

During 2006, our consolidated debt, including our senior notes, increased to $2.1 billion from $811.8 million as of December 31, 2005. The December 31, 2005 debt included $350.0 million associated with an interim bank loan which was funded on October 2, 2005 to finance the Equity Buyout. This interim bank loan was paid in full upon completion of our IPO on February 14, 2006. Prior to October 2, 2005, our borrowings under the EXCO Resources credit agreement were not significant. The increase to our consolidated debt in 2006 reflects borrowings under the EXCO Resources credit agreement and the EPOP Revolving Credit Facility and the EPOP Senior Term Credit Agreement to fund our 2006 acquisitions which occurred between February 14, 2006 and continued throughout the year. As a result, our 2006 interest expenses increased to $84.9 million from $46.1 million in non-GAAP combined 2005. On October 2, 2006, EPOP, a wholly-owned unrestricted subsidiary, closed on the acquisition of Winchester Energy. This acquisition was funded by a $650.0 million loan under the EPOP Senior Term Credit Agreement and $651.0 million of borrowings under the EPOP Revolving Credit Facility. EPOP's debt is not guaranteed by EXCO. The following table presents our interest expense, including increases of $31.6 million during the fourth quarter of 2006 of interest and amortization of deferred financing costs for EPOP.

	Predecessor		Successor				
(in thousands)	Year ended December 31, 2004	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	Successor Year ended December 31, 2006	Year to year change 2004-2005(a)	Year to year change 2005-2006(a)
Interest expense:							
7¼% senior notes due 2011	$28,638	$24,615	$ 7,269	$31,884	$29,275	$ 3,246	$ (2,609)
JP Morgan bridge loan	—	—	8,750	8,750	1,216	8,750	(7,534)
EXCO Resources credit agreement	868	193	90	283	15,951	(585)	15,668
Amortization and write-off of deferred financing costs on EXCO facilities	4,157	1,618	3,301	4,919	6,789	762	1,870
EPOP Revolving Credit Facility	—	—	—	—	11,937	—	11,937
EPOP Senior Term Credit Agreement	—	—	—	—	18,827	—	18,827
Amortization of deferred financing costs on EPOP loans	—	—	—	—	858	—	858
$50 million senior term loan	222	245	2	247	—	25	(247)
Interest rate swaps	685	—	—	—	—	(685)	—
Other interest expense	—	4	2	6	18	6	12
Total interest expense	$34,570	$26,675	$19,414	$46,089	$84,871	$11,519	$38,782

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

Interest expense for non-GAAP combined 2005 was $46.1 million compared with $34.6 million in 2004, an increase of $11.5 million, which is primarily attributable to the interest on the interim bank loan.

Income taxes

The following table presents a reconciliation of our income tax provision (benefit) for the year ended December 31, 2004, 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 year ended December 31, 2006.

	Predecessor		Successor	
(in thousands)	Year ended December 31, 2004	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
United States federal income taxes (benefit) at statutory rate of 35%	$(5,120)	$(70,293)	$ 8,150	$79,925
Increases (reductions) resulting from:				
Undistributed earnings of foreign subsidiary	8,237	—	—	—
Foreign tax items	—	644	(2,996)	—
Change in Canadian tax rates	(909)	—	—	—
Change in U.S. tax law related to Canadian dividend	—	(2,075)	—	—
Adjustments to the valuation allowance	—	—	—	—
Non-deductible compensation	—	15,432	604	1,420
Non-deductible intercompany foreign interest expense	1,840	—	—	—
State taxes net of federal benefit	880	(6,665)	1,095	8,704
Other	198	(741)	468	(648)
Total income tax provision	$ 5,126	$(63,698)	$ 7,321	$89,401

The income tax expense/benefit on our loss from continuing operations for the 12 months ended December 31, 2004 and the 275 day period from January 1, 2005 to October 2, 2005 and benefit on our income from continuing operations for the 90 day period from October 3, 2005 to December 31, 2005 differs from the amounts calculated using the U.S. federal statutory rate. The December 31, 2004 expense includes a $0.9 million tax benefit from reductions to income tax rates and provisions for the deduction of crown royalties in Canada which became effective in May 2004. This benefit is reflected as a component of continuing operations pursuant to SFAS No. 109 and EITF 93-13.

On October 22, 2004, the President signed the American Jobs Creation Act of 2004, or the Act. The Act created a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85% dividends received deduction for certain dividends from controlled foreign corporations. We repatriated Cdn. $74.5 million ($59.6 million) in an extraordinary dividend, as defined in the Act, from Addison on February 9, 2005. 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. The 275 day period ended October 2, 2005 also includes a $2.1 million tax benefit related to an extraordinary dividend received from Addison, our former wholly-owned Canadian subsidiary.

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 $0.9 million at December 31, 2006.

On February 10, 2005, we sold all of the issued and outstanding shares of common stock of Addison and two intercompany notes that Addison owed to ROJO. The aggregate purchase price after contractual adjustments was Cdn. $551.3 million ($443.3 million) less the payment of the outstanding balance under Addison's credit facility of Cdn. $90.1 million ($72.1 million). We have recognized a gain from the sale of Addison 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 Addison'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 Addison in 2005 on the intercompany notes.

The loss from discontinued operations of $4.4 million before the gain on the sale of Addison 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 Addison employees that were accelerated as a result of the sale.

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. The EXCO Resources credit agreement, as amended, is a $1.25 billion facility with a $600.0 million borrowing base and a $500.0 million aggregate commitment. The EPOP Revolving Credit Agreement is a $750.0 million facility with a $750.0 million borrowing base and aggregate commitment. On April 1, 2007, the conforming borrowing base on the

EPOP Revolving Credit Facility becomes $650.0 million. The EPOP Senior Term Credit Agreement is a $650.0 million facility. 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.

On February 14, 2006, EXCO Resources completed its IPO of 50,000,000 shares of its common stock for aggregate net proceeds to EXCO Resources of $617.5 million after underwriters' discount. The net proceeds from the IPO, together with cash on hand of $215.3 million and additional borrowings of $65.0 million 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 February 21, 2006, we issued 3,615,200 additional shares of our common stock pursuant to an exercise by the underwriters of their over-allotment option for net proceeds to EXCO Resources of approximately $44.7 million. The net proceeds were used to reduce outstanding indebtedness under the EXCO Resources credit agreement.

On February 10, 2005, we sold Addison for $443.3 million after contractual adjustments. The net cash proceeds could only be utilized by us in accordance with the terms of the Indenture governing the senior notes and our credit agreement. In addition, $120.6 million of these proceeds were pledged as collateral under our credit agreement and the senior notes. The credit agreement security interest on these proceeds was released in conjunction with the commencement of the senior notes purchase offer on November 2, 2005 related to the sale of Addison, or the Addison senior notes purchase offer. Upon completion of the Addison senior notes purchase offer on December 7, 2005, the senior notes security interest was released.

Net cash provided by operating activities was $227.7 million for the twelve months ended December 31, 2006. At December 31, 2006, our cash and cash equivalents balance was $22.8 million, a decrease of $204.1 million from December 31, 2005 primarily as a result of the repayment of indebtedness incurred in connection with the Equity Buyout and our acquisition of TXOK in the first quarter of 2006.

Acquisitions and capital expenditures

The following table presents our capital expenditures and entity acquisitions for the year ended December 31, 2004, 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 and the year ended December 31, 2006.

	Predecessor		Successor		
(in thousands)	Year ended December 31, 2004	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	Successor Year ended December 31, 2006
Property acquisitions	$ 88,347	$ 103,222	$ —	$ 103,222	$ 221,103
Acquisition of North Coast Energy, Inc., net of cash acquired	215,133	—	—	—	—
Acquisition of TXOK Acquisition, Inc. preferred stock, net of cash acquired	—	—	—	—	126,489
Acquisition of Power Gas Marketing & Transmission, Inc., net of cash acquired, excluding debt and derivative financial instruments assumed	—	—	—	—	61,776
Acquisition of Winchester Energy, Ltd., net of cash acquired	—	—	—	—	1,094,910
Lease purchases	—	—	—	—	8,991
Development capital expenditures	36,742	39,900	13,194	53,094	194,312
Other	7,543	5,944	1,712	7,656	10,980
Total expenditures	$347,765	$ 149,066	$ 14,906	$ 163,972	$ 1,718,561

On January 27, 2004, we completed the North Coast acquisition for $215.1 million. We funded the North Coast acquisition with the net proceeds from the $350.0 million offering of our senior notes.

In July and August 2004, we acquired natural gas properties located in Rusk County, Texas for a total purchase price of $36.9 million. We funded the acquisition with $32.0 million in borrowings under our credit agreement and from surplus cash. The properties acquired consisted of 32 producing natural gas wells, which we operate, and a number of proved undeveloped and unproved drilling locations.

In November and December 2004 we acquired working interests in, and became operator of, 228 oil and natural gas wells, unproved drilling locations and related natural gas gathering systems in Centre and Clearfield Counties, Pennsylvania. The total purchase price, after contractual adjustments, was approximately $40.0 million and was funded with borrowings under our credit agreement.

On January 21, 2005, we acquired producing natural gas properties and unproved drilling locations located in the Minden Field in East Texas for a total purchase price of $17.7 million. We funded the acquisition with $13.3 million in borrowings under the EXCO Resources credit agreement and from surplus cash. We also acquired a small natural gas gathering system as part of this acquisition for an additional $0.7 million.

In the third quarter of 2005, we acquired natural gas properties located in the Appalachia area for an aggregate purchase price of $81.7 million. We funded these acquisitions with surplus cash. The properties acquired consisted of 744 producing natural gas wells, which we operate, and over 500 future drilling locations, of which 320 were classified as proved.

For the year 2005, we spent approximately $53.1 million for drilling, exploitation and development capital expenditures in the United States and were contractually obligated to spend $13.4 million for our drilling and exploitation activities as of December 31, 2005.

During 2006, we completed the following acquisitions of oil and natural gas properties and undeveloped acreage, including the acquisition of Winchester, our largest acquisition to date. 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:			
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. The acquisition was accounted for as a purchase in accordance with SFAS No. 141.

On August 4, 2006, we acquired producing properties and undeveloped acreage in Wyoming. The purchase price of these assets was $27.5 million, subject to post-closing contractual adjustments, and was funded by $20.0 million of indebtedness drawn under the EXCO Resources credit agreement and $7.5 million of available cash.

On September 19, 2006, we acquired producing properties and undeveloped acreage in West Virginia. The purchase price, after contractual adjustments, was $49.4 million.

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 54 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.

On December 22, 2006, Vernon, our wholly-owned subsidiary, entered into the Vernon Purchase Agreement with Anadarko Petroleum Corporation and Anadarko Gathering Company to acquire the Vernon Assets for a purchase price of approximately $1.6 billion in cash, subject to certain purchase price adjustments. This acquisition is expected to close on or about March 30, 2007. On February 1, 2007, EXCO Resources entered into the Southern Gas Purchase Agreement with Anadarko Petroleum Corporation, Anadarko E&P Company, LP, Howell Petroleum Corporation, and Kerr-McGee Oil & Gas Onshore LP to acquire the Southern Gas Assets for a purchase price of approximately $860.0 million in cash, subject to certain purchase price adjustments. This acquisition is expected to close on or about May 2, 2007. See "Item 1. Business—Significant subsequent events" for a description of our pending acquisitions of the Vernon Assets and the Southern Gas Assets from Anadarko.

To ensure that we have sufficient financing to complete the pending acquisitions from Anadarko, we received a revised commitment letter dated as of February 1, 2007, from J.P. Morgan Securities Inc. and JPMorgan Chase Bank, N.A. This commitment letter supersedes and replaces the commitment letter we received on December 22, 2006 in conjunction with our entering into the Vernon Purchase Agreement. The new commitment letter, as subsequently supplemented, provides for a senior secured revolving credit facility commitment in the amount of $1.8 billion and an undertaking to arrange a bridge loan facility in the amount of $1.1 billion if requested, or collectively the new credit facilities. If used to finance these acquisitions, the new credit facilities will contain customary representations, warranties and covenants, and the closing of the new credit facilities will be subject to the satisfaction of customary closing conditions. We are also pursuing other financing alternatives, including a proposed private placement of preferred stock. For a discussion of the proposed terms of the preferred stock, see "—Proposed recapitalization."

During 2006, we sold oil and natural gas properties for proceeds totaling approximately $5.2 million. On January 5, 2007, we completed the sale of our oil and natural gas properties in the Wattenberg field in Colorado for $131.9 million. The proceeds from this sale were deposited with a qualified intermediary to effect a like-kind-exchange for Federal income tax purposes. The proceeds from this sale will be used to fund our pending acquisitions from Anadarko.

For 2007, we have budgeted approximately $314.7 million, excluding the pending acquisitions from Anadarko, for our development, exploitation and operational activities in the United States. We have also budgeted approximately $7.9 million in 2007 for our additional acquisition-related expenditures and approximately $2.0 for our information technology expenditures. In addition, we expect to add $80.4 million for projects associated with the pending acquisitions on a pro forma basis for 2007 (as if we acquired the pending acquisitions as of January 1, 2007). This additional capital brings our expected pro forma 2007 development, exploitation and operational program to $395.1 million.

We expect to utilize our current cash balance, cash flow from operations and available funds under our credit agreement to fund our acquisitions, capital expenditures and working capital. We also plan on selling 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 the Winchester acquisition. If cash flows decline we would 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 have experienced increased costs for tubular goods and for certain services during 2005 and 2006. Further, we have 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. If the conditions continue, however, projects may be delayed due to lack of services or materials or we may have to delay projects to stay within our capital budget.

7¼% senior notes due January 15, 2011

On January 20, 2004, we issued $350.0 million principal amount of our senior notes pursuant to Rule 144A and Regulation S under the Securities Act at a price of 100% of the principal amount. Approximately $168.3 million of the proceeds of the issuance of the senior notes was used to finance the acquisition of outstanding common stock, options and warrants of North Coast along with associated fees and expenses. Of the remaining proceeds, $113.8 million was used to repay a portion of our debt under our U.S. credit agreement, North Coast's credit facility indebtedness and accrued interest and fees, $50.1 million was used to repay in full principal and interest on our senior term loan, approximately $10.6 million was used to pay fees and costs associated with the offering, with the remainder, approximately $7.2 million, available for general working capital purposes.

On April 13, 2004, we issued an additional $100.0 million principal amount of our senior notes pursuant to Rule 144A at a price of 103.3% of the principal amount having the same terms and governed by the same Indenture as the senior notes issued on January 20, 2004. Of the total proceeds of $103.3 million, approximately $98.8 million was used to repay substantially all of our outstanding indebtedness under the Canadian credit agreement, approximately $1.2 million was used for fees and expenses associated with the offering, with the remainder, approximately $3.3 million, available for general working capital purposes.

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. If a change of control occurs, subject to certain conditions, we must offer holders of the senior notes an opportunity to sell us their senior notes at a purchase price of 101% of the principal amount of the senior notes, plus accrued and unpaid interest to the date of the purchase.

The Equity Buyout constituted a change of control under the Indenture governing our senior notes. As required by the Indenture, we commenced an offer to purchase all $450.0 million of senior notes outstanding at 101% of the principal amount plus accrued and unpaid interest through the date of purchase. The change of control offer expired on December 9, 2005 and $5.3 million in principal amount of senior notes were tendered, which was paid with available cash on hand, including the remaining net proceeds from the sale of Addison. As a result of the Equity Buyout, the carrying value of our senior notes was increased to $468.0 million, the fair value of the senior notes on October 3, 2005.

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.

On February 14, 2006, concurrent with the closing of our IPO, TXOK and its subsidiaries became restricted subsidiaries under and guarantors of the senior notes. On May 4, 2006, PGMT became a guarantor of the senior notes. In conjunction with the formation of EXCO Partners and the Winchester acquisition on October 2, 2006, certain of our existing subsidiaries, specifically ROJO Pipeline, Inc. and those TXOK subsidiaries that hold direct or indirect interests in certain of our East Texas assets were released from their guaranties under the senior notes and are now deemed unrestricted subsidiaries thereunder. EXCO Resources also contributed all of its directly held East Texas assets to EXCO Partners. EXCO Partners and its general partners, which are also subsidiaries of EXCO Resources, and all of EXCO Partners' subsidiaries are deemed unrestricted subsidiaries under the Indenture governing the senior notes and are not guarantors of the senior notes.

Credit agreements

EXCO Resources credit agreement

On March 17, 2006, EXCO Resources, Inc. and certain of its subsidiaries entered into an amended and restated credit agreement, or the EXCO Resources credit agreement, with certain lenders, JPMorgan Chase Bank, N.A., as administrative agent, and J.P. Morgan Securities Inc., as sole bookrunner and lead arranger. This amendment established a new borrowing base of $750.0 million under the EXCO Resources credit agreement reflecting the addition of the assets of TXOK. TXOK and its subsidiaries became guarantors of the EXCO Resources credit agreement. The amendment also provided for an extension of the EXCO Resources credit agreement maturity date to December 31, 2010. The borrowing base is redetermined each November 1 and May 1, beginning November 1, 2006. Our borrowing base is determined based on a number of factors including commodity prices. We use derivative financial instruments to lessen the impact of volatility in commodity prices. Financial covenants under the amended credit agreement require that we:

- maintain a consolidated current ratio (as defined under the EXCO Resources credit agreement) of at least 1.0 to 1.0 at the end of any fiscal quarter; and
- not permit our ratio of consolidated indebtedness to consolidated EBITDAX (as defined under the EXCO Resources credit agreement) to be greater than 3.5 to 1.0 at the end of each fiscal quarter.

Borrowings under the EXCO Resources credit agreement are collateralized by a first lien mortgage providing a security interest in 90% of our oil and natural gas properties including TXOK's Oklahoma properties and North Coast. and their respective subsidiaries. Our borrowings are collateralized by a first lien mortgage providing a security interest in the value of our Proved Reserves which is at least 125% of the aggregate commitment. The aggregate commitment is the lesser of (i) $1.25 billion and (ii) the borrowing base, however, the initial aggregate commitment was $300.0 million. This aggregate commitment increased to $500.0 million on May 11, 2006, was reduced to $400.0 million on October 2, 2006, and was increased back to $500.0 million on February 2, 2007.

At our option, borrowings under the EXCO Resources credit agreement accrue interest at one of the following rates:

- the sum of (i) the greatest of the administrative agent's prime rate, the base CD rate plus 1.0% or the federal funds effective rate plus 0.50% and (ii) an applicable margin, which ranges from 0.0% up to 0.75% depending on our borrowing usage; or
- the sum of (i) LIBOR multiplied by the statutory reserve rate and (ii) an applicable margin, which ranges from 1.0% up to 1.75% depending on our borrowing usage.

We typically elect to borrow funds using the LIBOR interest rate option described above. At December 31, 2005 and 2006, the six month LIBOR rates were 4.70% and 5.37% which would result in interest rates of approximately 5.95% and 6.62%, respectively, on any new indebtedness we may incur under the EXCO Resources credit agreement. At December 31, 2005 and 2006, we had $1,000 and $339.0 million, respectively, of outstanding indebtedness under the EXCO Resources credit agreement.

Additionally, the EXCO Resources credit agreement contains a number of other covenants regarding our liquidity and capital resources, including restrictions on our ability to incur additional indebtedness, restrictions on our ability to pledge assets, and a prohibition on the payment of dividends on our common stock. As of December 31, 2006, we were in compliance with the covenants contained in the EXCO Resources credit agreement.

In connection with the contribution by EXCO Resources to EXCO Partners of EXCO Resources' East Texas assets, EXCO Resources entered into an amendment to its credit agreement, or First

Amendment. The First Amendment generally consents to and facilitates the contribution of the East Texas assets to EXCO Partners and provides that EXCO Partners, its subsidiaries and its general partners, all of which are subsidiaries of EXCO, are unrestricted subsidiaries under the EXCO Resources credit agreement, are not subject to the terms thereof and are no longer guarantors thereof. In addition, the assets contributed by EXCO Resources were released from the mortgages securing the credit agreement. Moreover, the assets of EXCO Partners and its subsidiaries have not been pledged under the EXCO Resources credit agreement and none of EXCO Partners or the other unrestricted subsidiaries have guaranteed the EXCO Resources credit agreement. The First Amendment also provides that the borrowing base under the EXCO Resources credit agreement shall be reduced to $600.0 million, with an aggregate commitment of $400.0 million (increased back to $500.0 million on February 2, 2007). The First Amendment also revises the covenants regarding the format of the financial statements to be delivered by EXCO Resources and consents to the contingent equity contribution obligation described below under "EXCO Resources Equity Contribution Agreement" subject to certain conditions. The First Amendment also amends certain covenants to address the relationship with EXCO Partners. Prior to any public offering by EXCO Partners, EXCO Resources may not permit the subsidiaries through which EXCO Resources owns the equity of EXCO Partners to incur any indebtedness or incur any lien. Prior to any public offering by EXCO Partners, EXCO Resources is required to own 100% of the equity of EXCO Partners. As of February 28, 2007, $407.0 million of indebtedness was outstanding under the EXCO Resources credit agreement and we had $91.5 million of availability under the EXCO Resources credit agreement. Our consolidated debt as of February 28, 2007, which includes EPOP's debt, the EXCO Resources credit agreement and our senior notes, totals $2.2 billion. We are in compliance with the financial covenants of the EXCO Resources credit agreement as of December 31, 2006.

EPOP Revolving Credit Facility

To finance the Winchester acquisition and the $150.0 million payment to EXCO Resources for its East Texas assets, EXCO Partners' wholly-owned subsidiary, EPOP, entered into the EPOP Revolving Credit Facility dated October 2, 2006, with a group of lenders led by JPMorgan Chase Bank, N.A. The EPOP Revolving Credit Facility has a face amount of $750.0 million with an initial borrowing base of $750.0 million and an initial conforming borrowing base of $650.0 million. The conforming borrowing base is the amount of borrowings upon which interest is computed on a lower premium to LIBOR than borrowings which exceed the conforming borrowing base. The borrowing base must be conforming by April 1, 2007. The EPOP Revolving Credit Facility 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. We executed an amendment dated effective December 31, 2006, the EPOP Revolver First Amendment, which amends certain financial covenants contained in the EPOP Revolving Credit Facility. The EPOP Revolver First Amendment was sought due to our inability to comply with the leverage ratio and interest coverage ratio tests, as defined below, as of December 31, 2006. The original financial covenant ratios were negotiated assuming a more accelerated drilling program, which would have resulted in higher forecasted production. In addition, interest expense attributable to the EPOP Senior Term Credit Agreement was higher than originally forecast as the final negotiated interest rate exceeded our initial estimates when the covenants were being negotiated. Management and the lenders believe these revised covenants are more consistent with the actual operational activities contemplated at EPOP during 2007. As amended, the EPOP Revolving Credit Facility contains the following financial covenants:

- EPOP's Consolidated Current Ratio (as defined) as of the end of any fiscal quarter ending after September 30, 2006 is not permitted to be less than 1.00 to 1.00. The EPOP Revolver First Amendment did not revise this covenant.

- EPOP's ratio of (A) Consolidated Funded Indebtedness (as defined) as of the end of a fiscal quarter to (B) Consolidated EBITDAX (as defined) shall not be greater than:
  - 6.00 to 1.00 (increased from 5.00 to 1.00) for the quarter ending December 31, 2006. For purposes of the December 31, 2006 Consolidated EBITDAX, the December 31, 2006 quarter shall be multiplied by four (4);
  - 5.50 to 1.00 (increased from 4.00 to 1.00) for the first and second quarters of 2007 (Consolidated EBITDAX calculated using a defined trailing period multiplied by a fraction);
  - 5.50 to 1.00 (increased from 4.00 to 1.00) for the quarter ended September 30, 2007 (with Consolidated EBITDAX calculated using, for this quarter and all subsequent quarters, the trailing four quarter period ending on such date);
  - 5.25 to 1.00 (increased from 4.00 to 1.00) for the quarter ended December 31, 2007, and
  - 4.00 to 1.00 (unchanged) for any quarter ending on or after March 31, 2008.
- EPOP will not permit its ratio of Consolidated EBITDAX to Consolidated Interest Expenses (as defined) to be less than:
  - 1.50 to 1.00 (lowered from 2.50 to 1.00) as of the quarter ended December 31, 2006 (Consolidated EBITDAX and Consolidated Interest Expenses for such quarter to be multiplied by four);
  - 1.75 to 1.00 (lowered from 2.50 to 1.00) for the first and second quarters of 2007 (Consolidated EBITDAX and Consolidated Interest Expenses calculated using a defined trailing period multiplied by a fraction);
  - 1.75 to 1.00 (lowered from 2.50 to 1.00) for the quarter ended September 30, 2007 (with Consolidated EBITDAX and Consolidated Interest Expenses calculated using, for this quarter and all subsequent quarters, the trailing four quarter period ending on such date);
  - 2.00 to 1.00 (lowered from 2.50 to 1.00) as of the quarter ended December 31, 2007, and
  - 2.50 to 1.00 (unchanged) for any quarter ending on or after March 31, 2008.
- Finally, EPOP will not permit its ratio of net present value (calculated pursuant to the terms of the EPOP Revolving Credit Facility) to Consolidated Funding Indebtedness (as defined) to be less than (i) 1.15 to 1.00 (unchanged) determined as of December 31, 2006 or (ii)1.25 to 1.00 (unchanged) determined as of each succeeding June 30 and December 31.

The EPOP Revolving Credit Facility, as amended, contains representations, warranties, covenants, events of default, and indemnities customary for agreements of this type. The EPOP Revolving Credit Facility matures four years from the closing date and has an initial drawn interest rate of LIBOR + 175 basis points ("bps") and an undrawn commitment fee of 37.5 bps on the first $650.0 million of the EPOP Revolving Credit Facility. To the extent usage exceeds the initial conforming borrowing base, the EPOP Revolving Credit Facility will have an initial drawn interest rate of LIBOR + 250 bps and an undrawn commitment fee of 50 bps on the portion of the borrowings that exceed the initial conforming borrowing base. Finally, as a condition precedent to the funding of the EPOP Revolving Credit Facility, EPOP is required to hedge 75% of proved developed producing production through 2010. The repayment obligation under this facility can be accelerated upon the occurrence of an event of default including the failure to pay principal or interest, a material inaccuracy of a representation or warranty, failure to observe or perform covenants, subject to certain cure periods, bankruptcy, judgments against EPOP or any subsidiary in excess of $5.0 million or a change of control (as defined) of EPOP. The initial amount borrowed under this facility was $651.0 million at closing of the Winchester merger and the weighted average interest rate as of December 31, 2006, is 7.19%. As of February 28, 2007, $643.5 million was outstanding under this facility. We are in compliance with the financial covenants contained in the EPOP Revolving Credit Facility, as amended, as of December 31, 2006.

EPOP Senior Term Credit Agreement

In connection with the Winchester acquisition and the EXCO Resources asset contribution, EPOP entered into the EPOP Senior Term Credit Agreement, dated October 2, 2006 (as amended and restated as of October 13, 2006), with JPMorgan Chase Bank, N.A., as administrative agent. The aggregate principal amount is $650.0 million. The EPOP Senior Term Credit Agreement is secured by a second priority lien on all of the properties securing the EPOP Revolving Credit Facility, including 100% of the stock of subsidiaries, and is guaranteed by all existing and future subsidiaries. Financial covenants governing the EPOP Senior Term Credit Agreement include the same net present value ratio contained in the EPOP Revolving Credit Facility, a Leverage Ratio computed similarly to the covenant contained in the EPOP Revolving Credit Facility that cannot exceed 5.50 to 1.00 for applicable periods, and an Interest Coverage Ratio that cannot be less than 2.00 to 1.00 for any applicable period. The debt covenant tests for the EPOP Senior Term Credit Agreement begin with the quarter ended March 31, 2007. In addition, EPOP cannot make Capital Expenditures (as defined) exceeding $125.0 million in any fiscal year. The EPOP Senior Term Credit Agreement contains representations, warranties, covenants, events of default and indemnities customary for agreements of this type. The EPOP Senior Term Credit Agreement has an interest rate of LIBOR + 600 bps, with 25 bps step-ups on October 2, 2007 and January 2, 2008, and a total cap of LIBOR + 650 bps. Additionally, the EPOP Senior Term Credit Agreement matures five years from the closing date, requires payments of principle at 1% per year, with the balance of unpaid principle due at maturity. Upon an initial public offering by EXCO Partners, EPOP shall prepay the principal outstanding (plus accrued interest) under the EPOP Senior Term Credit Agreement at par plus an applicable premium. Commencing with the fiscal year ended December 31, 2007, and each year thereafter, EPOP must apply 100% of its Excess Cash Flow (as defined in the EPOP Senior Term Credit Agreement) toward prepayment at par of the EPOP Senior Term Credit Agreement. Such payments shall be made no later than the later of April 15 or five business days following delivery of the annual financial statements required under the EPOP Senior Term Credit Agreement. Any principal payment prior to the first anniversary, other than the mandatory cash flow and amortization prepayments described above, must be paid at 102% of the principal amount and after the first anniversary date to and including the second anniversary at 101% of par. Thereafter, any prepayments are at par. The repayment obligation under this facility can be accelerated upon the occurrence of an event of default including the failure to pay principal or interest, a material inaccuracy of a representation or warranty, failure to observe or perform covenants, subject to certain cure periods, bankruptcy, judgments against EPOP or any subsidiary in excess of $5.0 million or a change of control (as defined) of EPOP.

EXCO Resources Equity Contribution Agreement

In connection with the arrangement of the EPOP Senior Term Credit Agreement, the lenders required EXCO Resources to enter into an Equity Contribution Agreement, dated October 2, 2006, and amended and restated on October 4, 2006 and October 13, 2006. The Equity Contribution Agreement generally provides that on the date 18 months from October 2, 2006 (Equity Contribution Date), EXCO Resources will make a cash common equity contribution to EPOP in an amount equal to the lesser of (i) $150.0 million or (ii) the aggregate amount then outstanding under the EPOP Senior Term Credit Agreement; provided, that in no event can this obligation exceed during the term of the Equity Contribution Agreement the maximum amount that EXCO Resources could contribute under the terms of the Indenture governing its senior notes. Alternatively, EXCO Resources can cause EXCO Partners to make the equity contribution to EPOP in the amount of $150.0 million to satisfy this obligation. In lieu of requiring the equity contribution, the holders of at least 66⅔% of the aggregate principal amount of the loans outstanding under the EPOP Senior Term Credit Agreement can elect at the Equity Contribution Date to require EPOP and its subsidiaries to become "Restricted Subsidiaries" under the EXCO Resources credit agreement and require EXCO Resources to provide, and cause all then restricted subsidiaries as defined and constituted under the EXCO Resources credit agreement to provide, guarantees and collateral in respect of the EPOP Senior Term Credit Agreement on terms substantially consistent with the guarantees and collateral provided under the EXCO Resources credit agreement. This requirement is subject to compliance with the credit agreement. Any cash so contributed shall be used by EPOP to prepay loans under the EPOP Senior Term Credit Agreement. EXCO Resources is prohibited from making restricted payments (as defined in the Indenture) that would constitute a utilization of the Indenture restricted payment baskets, other than restricted payments not to exceed $5.0 million In addition, EXCO Resources has covenanted to redeem or defease its senior notes if the Indenture would not permit the equity contribution or the lenders' election to cause EXCO Resources to designate EPOP and its subsidiaries as restricted subsidiaries under the EXCO Resources credit agreement (subject to certain restrictions on the indebtedness that may be incurred for any such redemption or defeasance if the election to cause the designation of EPOP as a restricted subsidiary is chosen). The Equity Contribution Agreement will terminate upon payment in full of the EPOP Senior Term Credit Agreement.

Proposed recapitalization

If we consummate the proposed private placement of up to $2.0 billion of preferred stock, we plan to contribute $1.75 billion of the net proceeds to EPOP, of which approximately $1.6 billion will be used to purchase the Vernon Assets and approximately $150.0 million will be used to refinance EPOP's debt agreements. We expect the proposed refinancing of EPOP's debt agreements to include a new revolving credit facility, or the Proposed EPOP Revolving Credit Facility, and a new term loan, or the Proposed EPOP Term Loan, each with JPMorgan Chase Bank, N.A., as administrative agent. We anticipate that the EPOP Senior Term Credit Agreement will be paid in full and terminated in connection with the proposed recapitalization. We plan to use the remaining $250.0 million of the net proceeds of the preferred stock to restructure and repay indebtedness under the EXCO Resources credit agreement and pay fees and expenses associated with the offering.

We are in discussion with our lenders concerning all of our credit agreements. There is no assurance that any of these transactions will be completed. Even if the proposed recapitalization is completed, it may involve terms and conditions other than those provided in this annual report.

Proposed private placement of preferred stock

On February 14, 2007, we issued a press release pursuant to Rule 135c of the Securities Act of 1933 to announce a proposed offering of up to $2.0 billion in preferred stock through the private placement of up to $400.0 million of 6% Cumulative Convertible Perpetual Preferred Stock, or the 6% Convertible Preferred Stock, and $1.6 billion of 11% Cumulative Preferred Stock, or the 11% Preferred Stock, to accredited institutional investors pursuant to Regulation D of the Securities Act of 1933. We have not entered into definitive agreements with potential investors to issue any preferred stock. As a result, we may never issue any preferred stock. In addition, any preferred stock that we ultimately issue may contain terms different from those provided in this annual report.

The securities proposed to be offered in the private placement will not been registered under the Securities Act of 1933 or any state securities laws, and unless so registered may not be offered or sold in the United States, except pursuant to an exemption from, or in a transaction subject to, the registration requirements of the Securities Act of 1933 and applicable state securities laws. This annual report does not constitute an offer to sell, or the solicitation of an offer to buy, the securities nor shall there be any sale of the securities in any jurisdiction in which such offer, solicitation or sale would be unlawful prior to registration or qualification under the securities laws of any such jurisdiction.

The 6% Convertible Preferred Stock will be convertible into our common stock at a price of $20.00 per share, as may be adjusted in accordance with the terms of the 6% Convertible Preferred Stock, and we may force the conversion of the 6% Convertible Preferred Stock at any time if our common stock trades for 20 days within a period of 30 consecutive days at a price, subject to adjustment, above $35.00 per share in the 24 months after issuance, $30.00 per share thereafter through the 48th month after issuance and $25.00 per share at any time thereafter. Upon the occurrence of a change of control, holders of the 6% Convertible Preferred Stock may require us to repurchase their shares for cash or shares of common stock at the liquidation preference plus accumulated dividends. Holders of the 6% Convertible Preferred Stock will have a right of first offer with respect to our subsequent issuance of shares of common stock at a price per share less than the then-effective conversion price, subject to customary exceptions.

The 11% Preferred Stock will automatically convert into an equal number of shares of 6% Convertible Preferred Stock upon shareholder approval as required by New York Stock Exchange rules. We expect to hold a shareholders meeting in the third quarter of 2007. If the 11% Preferred Stock has not been converted into 6% Convertible Preferred Stock within 180 days of issuance, the annual dividend rate will increase by 0.50% per quarter (up to a maximum rate of 18% per annum) until the shares of 11% Preferred Stock have been converted into 6% Convertible Preferred Stock. The 11% Preferred Stock must be redeemed for cash at 125% of the liquidation preference plus accumulated dividends following the maturity of our senior notes and is otherwise redeemable at such price at our option at any time. Upon the occurrence of a change of control, holders of the 11% Preferred Stock may require us to repurchase their shares for cash at 101% of the liquidation preference plus accumulated dividends. In the event that any person or group of persons consummates a tender offer to acquire more than 50% of our total voting power at a price per common share equivalent of greater than the then effective conversion price of the 6% Convertible Preferred Stock, then, within 30 days after expiration of the change of control offer made to the holders of the 11% Preferred Stock following such tender offer, we must issue to each holder of 11% Preferred Stock, for all such shares of 11% Preferred Stock so held, the number of additional shares of 11% Preferred Stock having a liquidation preference equal to the product of (i) such number of shares of 11% Preferred Stock so held multiplied by (ii) the remainder of the tender offer price minus the then effective conversion price of the 6% Convertible Preferred Stock multiplied by (iii) the quotient of $1,000 divided by the then effective conversion price of the 6% Convertible Preferred Stock. No shares will be issued to any holder that requires us to purchase any of its 11% Preferred Stock pursuant to a change of control offer.

The holders of 11% Preferred Stock will have a class vote to approve (i) any sale or disposition of all or substantially all of our assets to a third party or (ii) any merger or consolidation of EXCO in which either the holders of our voting stock prior to the merger or consolidation do not beneficially own more than 50% of the voting stock of the continuing or surviving corporation immediately after such merger or consolidation or individuals not nominated by our current directors (or their successors nominated by the remaining directors) constitute two-thirds of our board of directors immediately following the merger or consolidation, unless each holder of the 11% Preferred Stock receives in the asset sale or the merger or consolidation the consideration it would have received had it been able to convert its 11% Preferred Stock into 6% Convertible Preferred Stock and the 6% Convertible Preferred Stock into our common stock immediately prior to the merger or consolidation. After 180 days from the date of issuance, holders of the 11% Preferred Stock will have a right of first offer with respect to our subsequent debt or equity issuances, subject to customary exceptions.

We must pay dividends quarterly either in cash at 6% per annum or the dividend due shall be added to the liquidation preference (thereby increasing the amount due at liquidation or upon conversion) at a rate equal to 8% per annum. After the sixth anniversary of the issue date, the dividend rate on the 6% Convertible Preferred Stock will increase to 8.0% per annum and dividends will be payable only in cash. Dividends on the 11% Preferred Stock are only payable in cash.

Holders of the 6% Convertible Preferred Stock and the 11% Preferred Stock will have certain director appointment rights. We will be obligated to register for resale under the Securities Act of 1933 the shares of common stock issuable in connection with the 6% Convertible Preferred Stock.

We will use the net proceeds from the sale of the preferred stock to finance our previously announced acquisition from Anadarko of oil and natural gas properties in the Vernon and Ansley Fields in Louisiana and to repay a portion of our outstanding indebtedness and indebtedness of our subsidiary, EPOP.

Proposed EPOP Revolving Credit Facility

The Proposed EPOP Revolving Credit Facility is expected to have a face amount of $1.0 billion with an initial borrowing base of $1.3 billion. The aggregate outstanding amount of the Proposed EPOP Term Loan will be deemed usage of the borrowing base. The borrowing base will 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 Proposed EPOP Revolving Credit Facility will be 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. We expect the Proposed EPOP Revolving Credit Facility to contain financial covenants similar to those contained in the current EXCO Resources credit agreement, including:

- a Consolidated Current Ratio;
- a ratio of (A) Consolidated Funded Indebtedness as of the end of a fiscal quarter to (B) Consolidated EBITDAX; and
- a ratio of Consolidated EBITDAX to Consolidated Interest Expense.

The Proposed EPOP Revolving Credit Facility will contain representations, warranties, covenants, events of default, and indemnities customary for agreements of this type. The Proposed EPOP Revolving Credit Facility matures five years from the closing date and has an initial drawn interest rate of LIBOR + 150 basis points ("bps") and an undrawn commitment fee of 37.5 bps.

The initial amount borrowed under this facility is expected to be $769.0 million at the closing of the acquisition of the Vernon Assets.

Proposed EPOP Term Loan

We expect that the Proposed EPOP Term Loan will have an aggregate principal amount of $300.0 million to be available in a single drawing on the closing date. The Proposed EPOP Term Loan will be secured by a first priority lien on all of the properties securing the Proposed EPOP Revolving Credit Facility, including 100% of the stock of EPOP's subsidiaries, and is guaranteed by all existing and future subsidiaries of EPOP. We expect the financial covenants governing the Proposed EPOP Term Loan to be substantially similar to those contained in the Proposed EPOP Revolving Credit Facility. We expect the Proposed EPOP Term Loan to contain representations, warranties, covenants, events of default and indemnities customary for agreements of this type. We expect the Proposed EPOP Term Loan to have an interest rate of LIBOR + 150 bps. Additionally, the Proposed EPOP Term Loan will mature six years from the closing date, require payments of principal at 1% per year, with the balance of unpaid principal due at maturity. We anticipate that any principal payment prior to the first anniversary, other than the mandatory amortization prepayments described above, must be paid at par.

We expect to draw down the full $300.0 million at the closing of the acquisition of the Vernon Assets.

Proposed EXCO Resources credit agreement

In connection with the proposed private placement of preferred stock, we plan to refinance the existing EXCO Resources credit agreement with a new EXCO Resources credit agreement, the Proposed EXCO Resources credit agreement, having a face amount of $750.0 million and a new borrowing base of $1.0 billion. The aggregate outstanding amount of a new term loan, or the Proposed EXCO Resources Term Loan, will be deemed usage of the borrowing base. The borrowing base will be redetermined on a semi-annual basis, with EXCO Resources 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. Borrowings under the Proposed EXCO Resources credit agreement will be collateralized by a first lien mortgage providing a security interest in our oil and natural gas properties. We anticipate that the financial covenants under the Proposed EXCO Resources credit agreement will be similar to those contained in the current EXCO Resources credit agreement, including:

- a Consolidated Current Ratio;
- a ratio of (A) Consolidated Funded Indebtedness as of the end of a fiscal quarter to (B) Consolidated EBITDAX; and
- a ratio of Consolidated EBITDAX to Consolidated Interest Expense.

The Proposed EXCO Resources credit agreement will contain representations, warranties, covenants, events of default, and indemnities customary for agreements of this type. The Proposed EXCO Resources credit agreement matures five years from the closing date and has an initial drawn interest rate of LIBOR + 125 basis points ("bps") and an undrawn commitment fee of 30.0 bps

Additionally, we expect the Proposed EXCO Resources credit agreement to contain a number of other covenants regarding our liquidity and capital resources, including restrictions on our ability to incur additional indebtedness, restrictions on our ability to pledge assets, and a prohibition on the payment of dividends on our common stock.

The initial amount borrowed under this facility is expected to be $482.0 million at the closing of the acquisition of the Southern Gas Assets.

Proposed EXCO Resources Term Loan

We expect that the Proposed EXCO Resources Term Loan will have an aggregate principal amount of $250.0 million to be available in a single drawing on the closing date. The Proposed EXCO Resources Term Loan will be secured by a first priority lien on all of the properties securing the Proposed EXCO Resources credit agreement. We expect the financial covenants governing the Proposed EXCO Resources Term Loan to be identical to those contained in the Proposed EXCO Resources credit agreement. We expect the Proposed EXCO Resources Term Loan to contain representations, warranties, covenants, events of default and indemnities customary for agreements of this type. We expect the Proposed EXCO Resources Term Loan to have an interest rate of LIBOR + 150 bps. Additionally, the Proposed EXCO Resources Term Loan will mature six years from the closing date, require payments of principal at 1% per year, with the balance of unpaid principal due at maturity. We anticipate that any principal payment prior to the first anniversary, other than the mandatory amortization prepayments described above, must be paid at par.

We expect to draw down the full $250.0 million of the Proposed EXCO Resources Term Loan at the closing of the acquisition of the Southern Gas Assets.

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. During the year ended December 31, 2005, we closed several of our derivative financial instrument contracts upon the payment of $67.6 million to our counterparties, of which $15.0 million was related to the sale of Addison and $52.6 million was related to our U.S. production. We also entered into new derivative financial instrument contracts at higher prices. As of December 31, 2006, 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 the acquisition of Winchester.

EXCO Resources, Inc. hedge positions as of December 31, 2006

	Swaps			
(in thousands, except average contract prices)	NYMEX gas volume—Mmbtus	Weighted average contract price per Mmbtu	NYMEX oil volume—Bbls	Weighted average contract price per Bbl
Q1 2007	11,880	$9.30	182	$70.03
Q2 2007	11,934	8.42	183	69.74
Q3 2007	11,988	8.46	185	69.40
Q4 2007	11,988	8.74	185	68.97
2008	43,140	8.63	327	62.67
2009	25,705	8.02	120	60.80
2010	6,985	6.63	108	59.85
2011	1,825	4.51	—	—
2012	1,830	4.51	—	—
2013	1,825	4.51	—	—

Pro forma including the acquisitions of the Vernon Assets and the Southern Gas Assets from Anadarko as of December 31, 2006

	Swaps			
(in thousands, except average contract prices)	NYMEX gas volume—Mmbtus	Weighted average contract price per Mmbtu	NYMEX oil volume—Bbls	Weighted average contract price per Bbl
Q1 2007	28,610	$8.18	359	$62.27
Q2 2007	31,044	7.78	456	61.53
Q3 2007	30,388	7.83	369	63.46
Q4 2007	30,388	8.07	369	63.83
2008	99,870	8.36	1,059	60.55
2009	73,155	7.89	850	60.10
2010	6,985	6.63	108	59.85
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, 2006:

	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)	—	—	339,000	—	339,000
EPOP Revolving Credit Facility(3)	—	—	643,500	—	643,500
EPOP Senior Term Credit Agreement(4)	6,500	12,806	630,694	—	650,000
Operating leases	5,834	9,877	6,238	2,236	24,185
Deferred compensation(5)	600	1,200	1,200	—	3,000
Drilling/work commitments	40,960	37,616	—	—	78,576
Total contractual cash obligations	$53,894	$61,499	$2,065,352	$2,236	$2,182,981

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

(2) The EXCO Resources credit agreement was amended and restated on March 17, 2006 and matures on December 31, 2010.

(3) The EPOP Revolving Credit Facility matures on October 2, 2010.

(4) The EPOP Senior Term Credit Agreement matures on October 2, 2011.

(5) Deferred compensation represents a Rabbi Trust for an officer of one of our subsidiaries. This obligation vests 20% each year and will fully vest on December 31, 2011.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE 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, 2006:

(in thousands, except prices)	Volume Mmbtus/Bbls	Weighted average strike price per Mmbtu/Bbl	Fair value at December 31, 2006
Natural Gas:			
Swaps:			
2007	47,790	$ 8.73	$82,659
2008	43,140	8.63	23,237
2009	25,705	8.02	3,943
2010	6,985	6.63	(4,664)
2011	1,825	4.51	(3,673)
2012	1,830	4.51	(2,929)
2013	1,825	4.51	(2,639)
Total Natural Gas	129,100		95,934
Oil:			
Swaps:			
2007	734	69.52	3,234
2008	327	62.67	(1,455)
2009	120	60.80	(670)
2010	108	59.85	(605)
Total Oil	1,289		504
Total Oil and Natural Gas			$96,438

At December 31, 2006, the average forward spot oil prices per Bbl for calendar 2007 and for 2008 were $65.02 and $67.50, respectively, and the average forward spot natural gas prices per Mmbtu for calendar 2007 and for 2008 were $6.97 and $8.06, respectively.

Realized gains or losses from the settlement of derivative financial instruments are recorded in our financial statements as increases or decreases in use of derivative financial instruments activities. For example, using the oil swaps in place at December 31, 2006, if the settlement price exceeded the actual weighted average strike price of $69.52, then a reduction in use of derivative financial instruments activities revenue would have been recorded for the difference between the settlement price and $69.52 multiplied by the hedged volume of 733,750 Bbls. Conversely, if the settlement price was less than $69.52, then an increase in use of derivative financial instruments activities revenue would have been recorded for the difference between the settlement price and $69.52 multiplied by the hedged volume of 733,750 Bbls. For example, for a hedged volume of 733,750 Bbls, if the settlement price was $70.52, then use of derivative financial instruments activities revenue would have decreased by $0.7 million. Conversely, if the settlement price was $68.52, use of derivative financial instruments activities revenue would have increased by $0.7 million.

Interest rate risk

At December 31, 2006, 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 7 ¼% on the $444.7 million in senior notes we have outstanding. As of December 31, 2006, 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, 2006, we had $1.6 billion in outstanding borrowings under our credit agreements. On February 14, 2006, we increased our borrowings under the EXCO Resources credit agreement to $65.0 million and subsequently repaid $44.5 million of that increase on February 21, 2006. On March 17, 2006, we borrowed $123.0 million under the EXCO Resources credit agreement and used these borrowings to repay in full the TXOK credit facility. This increased the outstanding balance under the EXCO Resources credit agreement to $143.5 million. As of March 1, 2007, the outstanding balance under our credit agreement was $407.0 million. The interest rate under the EXCO Resources credit agreement as of that date was 6.67%. A 1% change in interest rates based on the borrowings as of March 1, 2007 would result in an increase or decrease in our interest costs of $4.1 million per year. The interest we pay on these borrowings is set periodically based upon market rates.

The EPOP Revolving Credit Facility and the EPOP Senior Term Credit Agreement, both of which we entered into in connection with the Winchester acquisition on October 2, 2006, bear interest based on floating rates. As of December 31, 2006, we had $643.5 million and $650.0 million in outstanding borrowings under the EPOP Revolving Credit Facility and the EPOP Senior Term Credit Agreement, respectively. As of March 1, 2007, our outstanding balance under the EPOP Revolving Credit Facility was $643.5 million and under the EPOP Senior Term Credit Agreement was $650.0 million. As of that date, the interest rate under the EPOP Revolving Credit Facility averaged 7.19% and under the EPOP Senior Term Credit Agreement averaged 11.44%. A 1% change in interest rates based on the borrowings as of March 1, 2007 under the EPOP Revolving Credit Facility and the EPOP Senior Term Credit Agreement would result in an increase or decrease in interest costs of $6.4 million and $6.5 million per year, respectively.

The interest we pay on these borrowings is set periodically based upon market rates.

Marketable securities risk

On January 5, 2007, we deposited $129.6 million of proceeds, net of contractual adjustments, with a qualified intermediary to effect a like-kind exchange under Section 1031 of the Internal Revenue Code from the sale of our Wattenberg properties. These proceeds are invested in overnight money market funds.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EXCO RESOURCES, INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Contents

Financial information for the year ended December 31, 2004 and 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 Holdings II. See "Note 1. Organization" to the consolidated financial statements.

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheet of EXCO Resources, Inc. and subsidiaries (the Company) as of December 31, 2006, and the related consolidated statements of operations, shareholders' equity and comprehensive income, and cash flows for the year ended December 31, 2006. 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 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 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 audit provides 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, 2006, and the results of their operations and their cash flows for the year ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

KPMG LLP

Dallas, Texas
March 16, 2007

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of operations, of shareholders' equity and of cash flows present fairly, in all material respects, the financial position of EXCO Resources, Inc. and its subsidiaries (Successor Company) at December 31, 2005, and the results of their operations and their cash flows for 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 financial position and 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 21,
as to which the date is March 15, 2007

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 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 financial position and 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 21,
as to which the date is March 15, 2007

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, 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 year ended December 31, 2004 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.

/s/ PRICEWATERHOUSECOOPERS LLP
Dallas, Texas
March 31, 2006, except for Note 21,
as to which the date is March 15, 2007

EXCO Resources, Inc.
Consolidated balance sheets

(in thousands)	December 31, 2005	December 31, 2006
Assets		
Current assets:		
Cash and cash equivalents	$ 226,953	$ 22,822
Accounts receivable:		
Oil and natural gas sales	36,895	84,078
Joint interest	1,081	14,902
Canadian income taxes receivable	18,483	—
Interest and other	12,189	12,199
Related party	2,621	—
Deferred income taxes	29,968	—
Deferred costs of initial public offering	3,380	—
Oil and natural gas derivatives	—	91,614
Other	10,955	11,095
Total current assets	342,525	236,710
Investment in TXOK Acquisition, Inc.	20,837	—
Oil and natural gas properties (full cost accounting method):		
Unproved oil and natural gas properties	53,121	297,919
Proved developed and undeveloped oil and natural gas properties	873,595	2,492,863
Accumulated depreciation, depletion and amortization	(13,281)	(142,591)
Oil and natural gas properties, net	913,435	2,648,191
Gas gathering assets	27,028	203,537
Accumulated depreciation, depletion and amortization	(333)	(4,181)
Gas gathering assets, net	26,695	199,356
Office and field equipment, net	6,576	14,805
Advance on Vernon Assets	—	80,000
Oil and natural gas derivatives	—	41,469
Deferred financing costs, net	—	15,929
Goodwill	220,006	470,077
Other assets	419	520
Total assets	$1,530,493	$3,707,057

See accompanying notes.

EXCO Resources, Inc.
Consolidated balance sheets

(in thousands, except per share data)	December 31, 2005	December 31, 2006
Liabilities and shareholders' equity		
Current liabilities:		
Interim bank loan	$ 350,000	$ —
Accounts payable and accrued liabilities	25,182	54,402
Accrued interest payable	23,779	36,000
Revenues and royalties payable	11,266	53,994
Income taxes payable	901	89
Deferred income taxes payable	—	32,639
Current portion of asset retirement obligations	1,408	1,579
Current portion of long-term debt	—	6,500
Oil and natural gas derivatives	53,189	5,721
Total current liabilities	465,725	190,924
Long-term debt, net of current portion	461,802	2,081,653
Asset retirement obligations and other long-term liabilities	15,766	57,570
Deferred income taxes	134,912	166,136
Oil and natural gas derivatives	81,406	30,924
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $.001 par value; Authorized shares—10,000; none issued	—	—
Common stock, $.001 par value; Authorized shares—250,000;		
Issued and outstanding shares—50,000 at December 31, 2005 and 104,162 at December 31, 2006	50	104
Additional paid-in capital	354,482	1,024,442
Retained earnings	16,350	155,304
Total shareholders' equity	370,882	1,179,850
Total liabilities and shareholders' equity	$1,530,493	$3,707,057

See accompanying notes.

EXCO Resources, Inc.

Consolidated statements of operations

(in thousands, except per share data)	Predecessor Year ended December 31, 2004	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
Revenues and other income:				
Oil and natural gas	$141,993	$ 132,821	$70,061	$355,780
Gains (losses) on derivative financial instruments	(50,343)	(177,253)	(256)	198,664
Other income	1,184	7,096	2,374	5,005
Total revenues and other income	92,834	(37,336)	72,179	559,449
Cost and expenses:				
Oil and natural gas production	28,256	22,157	8,949	68,874
Depreciation, depletion and amortization	28,519	24,687	14,071	135,722
Accretion of discount on asset retirement obligations	800	617	226	2,014
General and administrative (includes $44.1 million, $2.2 million, and $6.5 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 year ended December 31, 2006, respectively)	15,466	89,442	6,375	41,206
Interest	34,570	26,675	19,414	84,871
Total cost and expenses	107,611	163,578	49,035	332,687
Equity in net income of TXOK Acquisition, Inc.	—	—	837	1,593
Income (loss) before income taxes	(14,777)	(200,914)	23,981	228,355
Income tax expense (benefit)	5,126	(63,698)	7,631	89,401
Income (loss) before discontinued operations	(19,903)	(137,216)	16,350	138,954
Discontinued operations:				
Income (loss) from operations	36,274	(4,403)	—	—
Gain on disposition of Addison Energy Inc.	—	175,717	—	—
Income tax expense (benefit)	10,358	49,282	—	—
Income from discontinued operations	25,916	122,032	—	—
Net income (loss)	$ 6,013	$ (15,184)	$16,350	$138,954
Earnings per share:				
Basic				
Net income (loss) from continuing operations	$ (0.17)	$ (1.18)	$ 0.35	$ 1.44
Net income (loss)	$ 0.05	$ (0.13)	$ 0.35	$ 1.44
Weighted average common shares outstanding	115,947	116,504	47,222	96,727
Diluted				
Net income (loss) from continuing operations	$ (0.17)	$ (1.18)	$ 0.35	$ 1.41
Net income (loss)	$ 0.05	$ (0.13)	$ 0.35	$ 1.41
Weighted average common and common equivalent shares outstanding	115,947	116,504	47,222	98,453

EXCO Resources, Inc.
Consolidated statements of cash flows

(in thousands)	Predecessor: Year ended December 31, 2004	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
Operating Activities:				
Net income (loss)	$ 6,013	$ (15,184)	$ 16,350	$ 138,954
Income from discontinued operations	(25,916)	(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)
Depreciation, depletion and amortization	28,519	24,687	14,071	135,722
Stock option compensation expense	—	44,092	2,207	6,532
Accretion of discount on asset retirement obligations	800	617	226	2,014
Non-cash change in fair value of derivatives	24,260	114,410	(21,954)	(169,241)
Deferred income taxes	3,681	(59,467)	15,964	89,401
Amortization of deferred financing costs, premium on 7¼% senior notes due 2011 and discount on long-term debt	3,859	1,320	2,381	4,733
Proceeds from sale of Enron claim	4,750	—	—	—
(Gains) losses from sales of marketable securities	(14)	3	—	—
Changes in working capital, net of acquisition effects:				
Accounts receivable	(2,487)	(24,512)	(2,533)	24,038
Other current assets	(1,307)	(369)	1,094	(3,727)
Accounts payable and other current liabilities	21,599	25,458	(18,792)	915
Net cash provided by (used in) operating activities of discontinued operations	54,771	(69,772)	—	—
Net cash provided by (used in) operating activities	118,528	(81,122)	8,177	227,659
Investing Activities:				
Investment in TXOK Acquisition, Inc.	—	—	(20,000)	—
Acquisition of North Coast Energy, Inc., less cash acquired	(215,133)	—	—	—
Additions to oil and natural gas properties, gathering systems and equipment	(139,521)	(151,144)	(13,207)	(434,166)
Proceeds from disposition of property and equipment	51,865	46,010	(393)	5,824
Payment to TXOK Acquisition, Inc. for preferred stock redemptions	—	—	—	(158,750)
Cash acquired in acquisition of TXOK Acquisition, Inc.	—	—	—	32,261
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 Vernon Assets	—	—	—	(80,000)
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	1,296	59	—	—
Net cash used in investing activities of discontinued operations	(79,983)	(442)	—	—
Other investing activities	—	—	263	—
Net cash provided by (used in) investing activities	(381,476)	337,880	(13,337)	(1,791,517)
Financing Activities:				
Proceeds from long-term debt	546,350	41,300	9,999	1,884,250
Payments on interim bank loan	—	—	—	(350,000)
Payments on long-term debt	(158,070)	(148,247)	(15,279)	(776,849)
Proceeds from issuance of common stock, net of underwriters' commissions and initial public offering costs	—	—	—	657,381
Principal and interest on notes receivable-employees	256	311	1,262	—
Settlement of derivative financial instruments on Power Gas Marketing & Transmission, Inc. acquisition	—	—	—	(38,098)
Deferred financing costs and other	(13,431)	—	—	(16,957)
Net cash provided by (used in) financing activities of discontinued operations	(91,397)	59,601	—	—
Net cash provided by (used in) financing activities	283,708	(47,035)	(4,018)	1,359,727
Net increase (decrease) in cash	20,760	209,723	(9,178)	(204,131)
Effect of exchange rates on cash and cash equivalents	(1,685)	—	—	—
Cash at beginning of period	7,333	26,408	236,131	226,953
Cash at end of period including cash of discontinued operations	26,408	236,131	226,953	22,822
Cash of discontinued operations at end of period	10,401	—	—	—
Cash at end of period	$ 16,007	$ 236,131	$226,953	$ 22,822
Supplemental Cash Flow Information:				
Interest paid	$ 17,102	$ 33,099	$ 124	$ 65,378
Income taxes paid	$ —	$ 38,213	$ 15,500	$ —
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
Supplemental non-cash investing:				
Capitalized stock compensation	$ —	$ —	$ 1,034	$ 1,401

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, 2003	127,873	$128	$ 173,804	$(1,829)	$ 4,146	$ 7,646	$ 183,895
Principal and interest payable	—	—	—	256	—	—	256
Foreign currency translation adjustments	—	—	—	—	—	13,704	13,704
Equity investments	—	—	—	—	—	17	17
Net income	—	—	—	—	6,013	—	6,013
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
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

See accompanying notes.

EXCO Resources, Inc.

Consolidated statements of comprehensive income (loss)

(in thousands)	Predecessor Year ended December 31, 2004	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
Net income (loss)	$ 6,013	$(15,184)	$16,350	$138,954
Other comprehensive income:				
Reclassification adjustment of foreign currency translation adjustment	13,704	—	—	—
Unrealized gain on equity investments, net of taxes of $9	17	—	—	—
Total comprehensive income (loss)	$19,734	$(15,184)	$16,350	$138,954

See accompanying notes.

EXCO Resources, Inc.

Notes to consolidated financial statements

1. Organization

Unless the context requires otherwise, references in this annual report to "EXCO," "EXCO Resources," "we," "us," "our" and the "Company" are to EXCO Resources, Inc., its consolidated subsidiaries and EXCO Holding Inc., or EXCO Holdings, our former parent company, which was acquired by and into which EXCO Holdings II, Inc., or Holdings II, merged on October 3, 2005. References in this annual report to "Resources" refers only to the registrant, EXCO Resources, Inc. On February 14, 2006, EXCO Holdings merged with and into Resources. As such, all periods presented reflect the merger and include EXCO Holdings.

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 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 investment, and manage our capital structure. On February 14, 2006, we acquired TXOK Acquisition, Inc., or TXOK, for approximately $665.1 million and on October 2, 2006, we completed the acquisition of Winchester Energy Company, Ltd., or Winchester, for approximately $1.1 billion in cash after closing adjustments. The Winchester acquisition was completed within our newly-formed subsidiary, EXCO Partners, LP, or EXCO Partners. Concurrent with the closing of this acquisition we contributed to EXCO Partners all of our East Texas assets, including four of our subsidiaries that own or operate certain of our East Texas assets in exchange for $150.0 million of cash and additional equity interests in EXCO Partners. EXCO Partners borrowed $1.3 billion to fund these transactions. Our 2006 acquisitions, including TXOK and Winchester, totaled in excess of $2.1 billion. In addition, we spent $214.3 million for development drilling, acreage and related oil and natural gas facilities during 2006. For a discussion of these acquisitions as well as other transactions that we completed during 2005 and 2006, see "Item 1. Business—Significant transactions during 2005" and "Item 1. Business—Significant transactions during 2006."

Due to the merger of our parent, EXCO Holdings (formerly EXCO Holdings II), into Resources on February 14, 2006 concurrent with the closing of our initial public offering, or IPO (See "Note 4. Significant recent transactions"), all financial information in this annual report contains the consolidated financial position and results of EXCO Resources and EXCO Holdings pursuant to presentation requirements contained in Statement of Financial Accounting Standards 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 year ended December 31, 2004 and the 275 day period from January 1, 2005 to October 2, 2005, financial information presented in our consolidated statements of operations, 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 year ended December 31, 2006, 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 with the consummation of the Equity Buyout and the acquisition by and merger of Holdings II into EXCO Holdings (See "Note 4. Significant recent transactions"). The Equity Buyout (See "Note 4. Significant recent transactions—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, 2005 and 2006 reflect this new basis of accounting.

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

The consolidated balance sheet as of December 31, 2005 reflects the consolidated financial position of EXCO and Holdings II (as successor for accounting purposes after its merger with EXCO Holdings) prior to the IPO of our common stock on February 9, 2006, which is more fully described below. The consolidated balance sheet as of December 31, 2006 reflects our consolidated financial position after the IPO and the merger of EXCO Holdings into EXCO Resources.

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, 2005 and 2006, results of operations, cashflows and changes in shareholders' equity for the year ended December 31, 2004, 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 year ended December 31, 2006 are for EXCO, its subsidiaries, and prior to the IPO, its parent. All intercompany transactions have been eliminated. Our results of operations reflect the results of our former Canadian subsidiary, Addison Energy Inc., or Addison, as discontinued operations. Certain prior year amounts have been reclassified to conform to the current year presentation.

The Equity Buyout

On August 29, 2005, EXCO announced that the Board of Directors of Holdings approved for consideration by the Holdings stockholders the proposed terms of an equity buyout (Equity Buyout) pursuant to a purchase of all of the outstanding shares of capital stock of Holdings by EXCO Holdings II, Inc. (Holdings II), a Delaware corporation controlled by a group of investors led by Douglas H. Miller, the Chairman and Chief Executive Officer of Holdings.

On October 3, 2005, Holdings II completed its purchase of all of the outstanding shares of capital stock of Holdings for an aggregate purchase price of approximately $699.3 million. The Equity Buyout was funded by a combination of (i) $350.0 million of interim loan indebtedness (interim bank loan), including $0.7 million for working capital, (ii) approximately $183.1 million from the issuance of Holdings II common stock to new private equity investors and EXCO employees and (iii) the exchange of Holdings Class A and Class B common stock valued at approximately $166.9 million for Holdings II common stock. Holdings' majority stockholder sold all of its shares for cash. JPMorgan Chase Bank, N.A. was the lead lender under the interim bank loan.

GAAP requires the application of "pushdown accounting" in situations where the ownership of an entity has changed. Holdings II was deemed to be the acquiror of Holdings. The assets and liabilities of Holdings II were recorded at their fair value, and, under Staff Accounting Bulletin (SAB) No. 54, "Pushdown Basis of Accounting in Financial Statements of Subsidiaries Acquired by Purchase", the fair value was allocated as follows:

(in thousands)	
Acquisition cost:	
Payments for shares	$ 478,836
Exchange of Holdings II shares for Holdings shares	166,884
Assumption of senior notes ($452,643 aggregate book value plus premium to fair value)	468,000
Assumption of long-term debt	1
Less cash assumed of $236,371, less cash compensation payments related to the Equity Buyout	(206,507)
Total Holdings acquisition cost	$ 907,214
Allocation of acquisition cost:	
Oil and natural gas properties—proved	$ 852,122
Oil and natural gas properties—unproved	58,573
Total oil and natural gas properties	910,695
Gas gathering assets and other equipment	33,073
Deferred tax asset ($3,471 reclassified to deferred tax liability)	—
Other assets, reflecting the reduction of deferred debt issuance costs of $8,862 to zero	285
Goodwill	220,006
Other current assets	50,898
Accounts payable and accrued expenses	(44,703)
Asset retirement obligations and other long-term liabilities	(17,538)
Oil and natural gas derivative liabilities	(156,549)
Deferred tax liability of $131,916 at an average marginal tax rate of 39.5%(1), net of $42,963 reclassification of Holdings historical deferred tax asset	(88,953)
Total allocation	$ 907,214

(1) Marginal tax rate includes federal income taxes at 35.0% plus a blended state tax rate of 4.5%.

As a result of the Equity Buyout, we recorded stock based and other compensation expense for the following items during the 275 day period from January 1, 2005 to 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 Holdings held by members of our management and other employees. The offset to this expense was to Shareholders' Equity as additional paid-in capital. The shareholder agreements governing the Class A and Class B shares of Holdings provided that, upon the occurrence of certain specified events, including a change of control as occurred upon the Equity Buyout:
  - the holders of the Class A shares were to receive the first $175.0 million in proceeds, and
  - the remaining proceeds in excess of the $175.0 million were to be allocated on a pro-rata basis to the holders of the Class A and 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 a participation event, such as a change of control, to receive fair value for the Class B shares.

- A charge of $17.8 million for payments made to holders of options to purchase Class A shares of Holdings less options held by the Employee Stock Participation Plan (ESPP). This amount was paid to option holders at the time of the Equity Buyout by Holdings to purchase all stock options outstanding at that time. The amount represents the cumulative difference between the $5.197 per share purchase price for the Equity Buyout 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 at the time of the Equity Buyout and was based upon shares of Holdings Class A and Class B stock that were reserved, but unissued, and options granted to the ESPP under the Holdings' 2004 Long-Term Incentive Plan (the Holdings Plan). All employees on the date of the Equity Buyout who were not direct owners of Holdings Class A or Class B 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 Holdings to certain employees of EXCO under the Holdings Bonus Retention Plan. The Holdings Bonus Retention Plan was accelerated, paid in full and terminated upon consummation of the Equity Buyout.

Holdings II adopted the 2005 Long-Term Incentive Plan (the 2005 Incentive Plan) which provides for the granting of options to purchase up to 10,000,000 shares of Holdings (formerly Holdings II) common stock. On October 5, 2005, options were granted under the 2005 Incentive Plan to our employees to purchase 4,992,650 shares of Holdings common stock at $7.50 per share. During 2006, a total of 3,615,700 options to purchase shares of our common stock were granted at a weighted average price of $14.02. As of December 31, 2006, a total of 8,267,373 options were issued and outstanding. 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 the grant. As a result of the new basis in accounting due to the Equity Buyout, we adopted the provisions of SFAS No. 123(R), "Share-Based Payment" as of October 3, 2005. During 2006, we recorded non-cash compensation of $6.5 million as general and administrative expenses and capitalized $1.4 million as oil and natural gas properties.

Merger of Holdings II into Holdings

Promptly following the consummation of the Equity Buyout, Holdings II merged with and into Holdings (Holdings II Merger). As a result of the Holdings II Merger, each outstanding share of Holdings II common stock was cancelled and exchanged for one share of Holdings common stock. In addition, all shares of Holdings Class A and Class B common stock held by Holdings II were cancelled in connection with the Holdings II Merger. The Equity Buyout was accounted for as a purchase pursuant to SFAS No. 141, which resulted in the assets and liabilities being recorded at their fair value. Holdings II is deemed the accounting acquiror of Holdings.

Pursuant to the Holdings II Merger, the indebtedness incurred by Holdings II to fund the Equity Buyout was assumed by Holdings.

2. Summary of significant accounting policies

Principles of consolidation

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

The accompanying results of operations, cash flows and comprehensive income for the year ended December 31, 2004 and for the 275 day period from January 1, 2005 to October 2, 2005 are for EXCO and its subsidiaries and represent the stepped up Predecessor basis of accounting.

The financial statements prior to January 1, 2005 have been restated to reflect the financial position, operations, cash flow and comprehensive income of Addison as discontinued operations.

All intercompany transactions and accounts have been eliminated.

Functional currency

The assets, liabilities and operations of Addison were measured using the Canadian dollar as the functional currency. These assets and liabilities were translated into U.S. dollars using end-of-period exchange rates. Revenue and expenses were translated into U.S. dollars at the average exchange rates in effect during the period. Translation adjustments were deferred and accumulated in other comprehensive income.

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 period. The most significant estimates pertain to proved oil and natural gas reserve volumes, future development, 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 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 operated wells. Oil and natural gas sales are generally uncollateralized. The allowance for doubtful accounts receivable (including current assets of discontinued operations) aggregated $1.6 million and $1.9 million at December 31, 2005 and 2006, 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 7. 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 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 allowed by SFAS No. 133 exist. We have not designated our derivative financial instruments as hedging instruments and, as a result, we recognize the change in the derivative's fair value currently in earnings.

Oil and natural gas properties

We have recorded oil and natural gas properties at cost using the full cost method of accounting. Under the full cost method, all costs associated with the acquisition, exploration or development of oil and natural gas properties are capitalized as part of the full cost pool. Capitalized costs are limited to the aggregate of the after-tax present value of future net revenues plus the lower of cost or fair market value of unproved properties. The full cost pool is comprised of lease and well equipment and exploration and development costs incurred, plus costs of acquired proved leaseholds.

Unproved oil and natural gas properties are excluded from the calculation of depreciation, depletion and amortization until it is determined whether or not Proved Reserves can be assigned to such properties. At December 31, 2005 and 2006, the $53.1 million and $297.9 million, respectively, in unproved oil and natural gas properties resulted from the allocation of the estimated fair value of undeveloped acreage and unproved reserves. We assess our unproved oil and natural gas properties for impairment on a quarterly basis.

Depreciation, depletion and amortization of evaluated oil and natural gas properties is calculated separately for the United States and until February 10, 2005, the Canadian full cost pools using the unit-of-production method based on total Proved Reserves, as determined by independent petroleum reservoir engineers.

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.

Full cost ceiling test

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). This ceiling test calculation is done separately for the United States and, until February 10, 2005, the Canadian full cost pools.

As of December 31, 2006, pursuant to Rule 4-10(c)(4)(i)(A) of Regulation S-X, the Company was required to compute its ceiling test using the December 31, 2006 spot prices for oil and natural gas. The computation resulted in the carrying costs of our unamortized proved oil and natural gas properties, net of deferred taxes, exceeding the December 31, 2006 present value of future net revenues by approximately $393.7 million, of which approximately $189.1 million is attributable to our Winchester and TXOK acquisitions. The December 31, 2006 spot price per equivalent Mcf was less than the Company's realized prices for 2006 by approximately 27% and approximately 38% including realized derivative settlements. Even though the December 31, 2006 prices for oil and natural gas indicated impairment, the spot price for natural gas and oil increased to $7.05 per Mmbtu and $60.03 per Bbl., respectively, on March 12, 2007, a level sufficient to eliminate the need for a ceiling test write-down.

In advance of the 2007 price recovery that eliminated the need for a ceiling test write-down, the Company requested, and received, an exemption from the SEC to exclude all of its 2006 Acquisitions, or the 2006 Acquisitions, from the full cost pool ceiling test assessments for a period of twelve months following December 31, 2006 (i.e. through the filing of our September 30, 2007 Form 10-Q). Accordingly, we will initially test the 2006 Acquisitions for impairment in conjunction with the preparation of our financial statements for the year ended December 31, 2007, provided that we can demonstrate that the fair value of the 2006 Acquisitions exceeds the carrying costs in the interim periods through September 30, 2007.

The allocated value of proved properties for the 2006 Acquisitions totaled approximately $1.6 billion, which represented an increase of over 250% to the full cost pool from December 31, 2005. The request for exemption was made because the Company believes the fair value of the 2006 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 2006 Acquisitions for impairment during the 2007 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.

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", 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 and 2006 (in thousands):

Predecessor:	
Balance as of December 31, 2004(1)	$ 19,984
Successor:	
Equity Buyout (see "Note 1. Organization")	$220,006
Activity during the 90 day period from October 3, 2005 to December 31, 2005	—
Balance as of December 31, 2005	220,006
Acquisition of TXOK Acquisition, Inc.	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	$470,077

(1) Goodwill from the going private transaction was written off as a result of the Equity Buyout.

Deferred abandonment and asset retirement obligations

In June 2001, the Financial Accounting Standards Board issued SFAS No. 143, "Accounting for Asset Retirement Obligations". 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. EXCO adopted the new rules on asset retirement obligations on January 1, 2003.

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

	Predecessor		Successor	
	For the year ended December 31, 2004	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
Asset retirement obligation at beginning of period	$ 6,687	$13,247	$14,275	$15,823
Activity during the period:				
Adjustment to liability due to purchase of EXCO by Holdings in 2003 and Holdings II in 2005	—	—	1,607	—
Adjustment to liability due to 2006 Acquisitions	—	—	—	16,954
Liabilities incurred during period	8,462	1,686	51	21,681
Liabilities settled during period	(2,702)	(1,275)	(336)	(323)
Accretion of discount	800	617	226	2,014
Asset retirement obligation at end of period:	13,247	14,275	15,823	56,149
Less current portion	2,418	1,713	1,408	1,579
Long-term portion	$10,829	$12,562	$14,415	$54,570

We have no assets that are legally restricted for purposes of settling asset retirement obligations, however we maintain a letter of credit of $1.5 million for plugging costs. This letter of credit expires on September 28, 2007.

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, 2005 and 2006 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 year ended December 31, 2004, 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 year ended December 31, 2006, we have capitalized $1.6 million, $1.2 million, $1.5 million and $3.3 million, respectively. Included in the $1.5 million and $3.3 million are $1.0 million and $1.4 million of share based compensation for the 90 day period from October 3, 2005 to December 31, 2005 and the year ended December 31, 2006, respectively, resulting from the adoption of SFAS No. 123(R) on October 3, 2005. See "Note 14. Stock transactions" for further discussion.

Overhead reimbursement fees

We have classified fees from overhead charges billed to working interest owners, including ourselves, of $2.1 million, $1.3 million, $0.5 million and $7.8 million, for the year ended December 31, 2004, 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 year ended December 31, 2006, respectively, as a reduction of general and administrative expenses in the accompanying statements of operations. Our share of these charges was

$1.5 million, $0.8 million, $0.3 million and $5.5 million for the year ended December 31, 2004, 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 year ended December 31, 2006, 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 Statement of Financial Accounting Standards No. 128, "Earnings Per Share", or SFAS No. 128. SFAS No. 128 requires companies to present two calculations of earnings per share; 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. 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.

Holdings (formerly Holdings II) adopted the 2005 Long-Term Incentive Plan (the 2005 Incentive Plan) which provides for the granting of options to purchase up to 10,000,000 shares of Holdings 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.

SFAS No. 123, "Accounting for Stock-Based Compensation" defines a fair value based method of accounting for employee stock compensation plans, but allows for the continuation of the intrinsic value based method of accounting to measure compensation cost prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25). For companies electing not to change their accounting, SFAS 123 requires pro forma disclosures of earnings and earnings per share as if the change in accounting provision of SFAS 123 has been adopted.

EXCO elected to continue to utilize the accounting method prescribed by APB 25 until October 3, 2005, under which no compensation cost was recognized, and adopted the disclosure requirements of SFAS 123.

Certain employees were granted Holdings stock options under Holdings' 2004 Long-Term Incentive Plan (the Holdings Plan). The Holdings Plan provides for grants of stock options that could have been exercised for Class A common shares of Holdings. The stock options were to vest upon the earlier of a change in control of Holdings, the consummation of an initial public offering or three years from the date of grant, and expire ten years after the date of grant. Holdings had reserved 12,962,968 shares of its Class A common stock for issuance upon the exercise of stock options. The Equity Buyout was a change of control under the Holdings Plan. All Holdings stock options outstanding on October 3, 2005 (8,671,906 shares) were cancelled upon the payment of an aggregate amount of $17.8 million to the holders of the stock options. This amount was expensed as general and administrative expense during the 275 day period from January 1, 2005 to October 2, 2005.

Foreign currency translation

Addison, our former Canadian subsidiary, entered into a long-term note agreement with a U.S. subsidiary of EXCO in the amount of $98.8 million. Addison used the proceeds of this borrowing to repay virtually all of its outstanding indebtedness under its Canadian credit agreement in April 2004. The indebtedness was denominated in U.S. dollars and was repaid upon the sale of Addison on February 10, 2005. Under the provisions of SFAS No. 52 "Foreign Currency Translation", Addison was required to recognize any foreign transaction gains or losses in its statement of operations when translating this liability from U.S. dollars to Canadian dollars. Gain or loss recognized by Addison was not eliminated when preparing EXCO's consolidated statement of operations. As a result, we recorded a non-cash foreign currency transaction gain of $10.8 million during the year ended December 31, 2004 and a non-cash foreign currency loss of $3.5 million for the 275 day period from January 1, 2005 to October 2, 2005. These amounts are included in income (loss) from operations of discontinued operations in the accompanying consolidated statements of operations.

3. Recent accounting pronouncements

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 No. 109, "Accounting for Income Taxes". FIN 48 provides guidance on recognizing, measuring, presenting and disclosing in the financial statements uncertain tax positions that a company has taken or expects to take on a tax return. FIN 48 is effective as of January 1, 2007. We do not believe the adoption of FIN 48 will have a material impact on our consolidated financial position or results of operations.

In September 2006, the Securities and Exchange Commission Staff issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," or SAB 108, in an effort to address diversity in the accounting practice of quantifying misstatements and the potential for improper amounts on the balance sheet. Prior to the issuance of SAB 108, the two methods used for quantifying the effects of financial statement errors were the "roll-over" and "iron curtain" methods. Under the "roll-over" method, the primary focus is the income statement, including the reversing effect of prior year misstatements. The criticism of this method is that misstatements can accumulate on the balance sheet. On the other hand, the "iron curtain" method focuses on the effect of correcting the ending balance sheet, with less importance on the reversing effects of prior year errors in the income statement. SAB 108 establishes a "dual approach" which requires the quantification of the effect of financial statement errors on each financial statement, as well as related disclosures. Public companies are required to record the cumulative effect of initially adopting the "dual approach" method in the first year ending after November 16, 2006 by recording any necessary corrections to asset and liability balances with an offsetting adjustment to the opening balance of retained earnings. The use of this cumulative effect transition method also requires detailed disclosures of the nature and amount of each error being corrected and how and when they arose. We adopted SAB 108 in the fourth quarter of 2006. The adoption did not have a material impact on our financial position, results of operations and cash flows.

In September 2006, the FASB issued Statement of Financial Accounting Standards 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. We will be required to adopt SFAS No. 157 in the first quarter of fiscal year 2008. We are currently evaluating the impact of SFAS No. 157 on our financial statements.

4. Recent significant transactions

TXOK acquisition

On September 16, 2005, Holdings II formed TXOK for the purpose of acquiring ONEOK Energy Resources Company and ONEOK Energy Resources Holdings, L.L.C., or collectively, ONEOK Energy. Prior to TXOK's acquisition of ONEOK Energy, BP EXCO Holdings LP, an entity controlled by Mr. Boone Pickens, one of our directors, held all of the outstanding shares of TXOK preferred stock and EXCO Holdings owned all of the issued and outstanding common stock of TXOK. On September 27, 2005, TXOK completed the acquisition of ONEOK Energy for an aggregate purchase price of approximately $633.0 million after contractual adjustments. Effective upon closing, ONEOK Energy Resources Company and ONEOK Energy Resources Holdings, L.L.C. became wholly-owned subsidiaries of TXOK. EXCO Holdings purchased an additional $20.0 million of Class B common stock of TXOK on October 7, 2005, which investment represented an 11% equity interest and a 10% voting interest in TXOK. The preferred stock of TXOK held by BP EXCO Holdings LP represented the remaining 89% equity interest and 90% voting interest of TXOK.

TXOK funded the acquisition of ONEOK Energy with (i) $20.0 million in private debt financing, $15.0 million of which was provided by Mr. Pickens, which was subsequently repaid; (ii) the issuance of $150.0 million of 15% Series A Convertible Preferred Stock of TXOK, or the TXOK preferred stock, to BP EXCO Holdings LP; (iii) approximately $308.8 million of borrowings under the revolving credit facility of TXOK, or the TXOK credit facility; and (iv) $200.0 million of borrowings under the second lien term loan facility of TXOK, or the TXOK term loan.

Prior to TXOK's redemption of the preferred stock concurrently with the IPO, we held an 11% economic interest in TXOK and used the equity method of accounting for that investment until the merger.

Equity Buyout

On October 3, 2005, Holdings II, an entity formed by our management, purchased 100% of the outstanding equity securities of EXCO Holdings in an equity buyout, or Equity Buyout, for an aggregate price of approximately $699.3 million, resulting in a change of control and a new basis of accounting. To fund the Equity Buyout, Holdings II raised $350.0 million in interim debt financing, including $0.7 million for working capital, from a group of lenders and $183.1 million of equity financing from new institutional and other investors as well as stockholders of EXCO Holdings. In addition, current management and other stockholders of EXCO Holdings exchanged $166.9 million of their EXCO Holdings common stock for Holdings II common stock. EXCO Holdings' majority stockholder sold all of its EXCO Holdings common stock for cash. Promptly following the completion of the Equity Buyout, Holdings II merged with and into EXCO Holdings. As a result of the merger, each outstanding share of Holdings II common stock was cancelled and exchanged for one share of EXCO Holdings common stock and all shares of EXCO Holdings common stock held by Holdings II were cancelled.

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 $662.1 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. Concurrently 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, Resources 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 reflect 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 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
Assumption of debt:	
Term loan, plus accrued interest	202,755
Revolving credit facility plus accrued interest	309,701
Less cash acquired	(32,261)
Total TXOK Acquisition, Inc. 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
Goodwill	64,887
Current and non-current assets	37,460
Deferred income taxes	26,783
Accounts payable and other accrued expenses	(30,377)
Asset retirement obligations	(8,203)
Fair value of oil and natural gas derivatives	4,598
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 calculations:	
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:	
Proved properties	$122,972
Unproved properties	421
Deferred taxes, net	(31,424)
Current assets	2,024
Land, field equipment and other assets	2,573
Current liabilities	(3,267)
Asset retirement obligations	(1,527)
Other liabilities	(51)
Goodwill	21,249
Total allocation of purchase price	$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, subject to purchase price adjustments, which was funded with indebtedness, as discussed below and in Note 8. 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:	
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
Goodwill	163,935
Current and non-current assets	31,872
Deferred income taxes	—
Accounts payable and other accrued expenses	(39,420)
Asset retirement obligations	(7,793)
Fair value of oil and natural gas derivatives	57,193
Total purchase price allocation	$1,094,910

Pro forma results of operations

The following table reflects the unaudited pro forma results of operations as though the acquisitions of TXOK, PGMT and Winchester had occurred at the beginning of each respective period (in thousands except per share data):

(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	For the year ended December 31, 2006
Revenues and other income	$ 177,774	$207,390	$762,578
Income (loss) from continuing operations	(133,545)	44,259	146,445
Net income (loss)	(87,333)	44,259	146,445
Basic earnings per share	$ (0.84)	$ 0.43	$ 1.51
Diluted earnings per share	$ (0.84)	$ 0.41	$ 1.49

Acquisition of North Coast Energy, Inc.

On November 26, 2003, EXCO entered into the North Coast Acquisition Agreement, as amended and restated on December 4, 2003, to acquire all of the issued and outstanding stock of North Coast pursuant to a tender offer and merger. EXCO acquired all of the outstanding common stock, options and warrants of North Coast on January 27, 2004 for a purchase price of $168.0 million, including transaction related costs, and we assumed $57.1 million of North Coast's outstanding indebtedness. As a result, on January 27, 2004, North Coast became a wholly-owned subsidiary and established a new core operating area for us in the Appalachian Basin. We have accounted for the North Coast acquisition using the purchase method of accounting and have consolidated its operations effective January 27, 2004.

The following table reflects the unaudited pro forma results of operations for the year ended December 31, 2004. The information for the year ended December 31, 2004 has been derived from our audited consolidated statement of operations for the year ended December 31, 2004 and North Coast's unaudited consolidated financial statement of operations for the 26 day period from January 1 to January 26, 2004. The pro forma results of operations give effect to the payment of our related fees and expenses as if each occurred on January 1, 2004.

During North Coast's 26 day period from January 1, 2004 to January 26, 2004, there was $11.9 million in investment banking fees, employee bonus and severance payments and other costs incurred in connection with the merger with EXCO that have been excluded from net income in the following table:

(in thousands)	For the year ended December 31, 2004
Revenues and other income	$99,544
Net income	$ 8,306
Basic and diluted earnings per share	$ 0.07

The pro forma information presented herein does not purport to be indicative of the financial position or results of operations that would have actually occurred had the events discussed above occurred on the dates indicated or which may occur in the future.

5. Sale of Addison Energy Inc.

On January 17, 2005, our directors approved the Share and Debt Purchase Agreement (the Addison Purchase Agreement), dated effective January 12, 2005, among 1143928 Alberta Ltd., a corporation organized under the laws of the Province of Alberta (Purchaser) and a wholly-owned subsidiary of NAL Oil & Gas Trust, an Alberta trust, EXCO and Taurus Acquisition, Inc. (Taurus), our wholly-owned subsidiary. The Addison Purchase Agreement provided that EXCO would sell to Purchaser all of the issued and outstanding shares of common stock of Addison Energy Inc. (Addison), which was at that time our wholly-owned Canadian subsidiary. The Addison Purchase Agreement also provided that Taurus would sell to Purchaser a promissory note in the amount of U.S. $98.8 million and a promissory note in the amount of Cdn. $108.3 million (U.S. $79.3 million) (collectively, the Addison Notes), each of which were issued by Addison in favor of Taurus. This transaction closed on February 10, 2005.

The aggregate purchase price for the stock and the Addison Notes was Cdn. $551.3 million (U.S. $443.4 million). Of this amount Cdn. $90.1 million (U.S. $72.1 million) was used to repay in full all outstanding balances under Addison's credit facility while Cdn. $56.2 million (U.S. $45.2 million) was withheld and has been remitted to the Canadian government for potential income taxes that we may owe resulting from the sale of the stock. As of December 31, 2005, we had a receivable in the amount of Cdn. $21.5 million (U.S. $18.5 million) for the excess of the amount withheld for Canadian income taxes from the sales proceeds over the estimated amount of Canadian income taxes that were actually owed on the gain from the sale which was received in March 2006. The purchase price was subject to further adjustment based upon, among other items, the final determination of Addison's working capital balance. In June 2005, we adjusted the liability and the gain recognized on the sale by Cdn. $1.6 million (U.S. $1.3 million). In October 2005, we paid the Purchaser the Cdn. $1.6 million (U.S. $1.1 million) in settlement of the working capital balance. The purchase price remains subject to additional adjustments based upon the outcome of Crown royalty and joint venture audits, if any, that may occur in the future that cover periods prior to February 1, 2005.

All severance payments paid or payable in respect of employees terminated up to May 31, 2005 were borne by EXCO. If Purchaser or its affiliates made an employment offer to a terminated employee and the employee accepted the offer, Purchaser was obligated to pay EXCO an amount equal to all severance payments paid to that employee. This obligation was in effect for a period of six months for any employee terminated at closing and for an indefinite period for any employee terminated after closing but prior to May 31, 2005. At closing, Cdn. $2.1 million (U.S. $1.7 million) was deducted from the sales proceeds for severance payments made to Addison employees who were terminated at closing.

We recognized a gain from the sale of Addison in the amount of U.S. $175.7 million before income tax expense of U.S. $49.3 million related to the gain. The cumulative adjustment resulting from the translation of Addison's financial statements was eliminated as these amounts were considered in the determination of the gain on the sale.

The following table presents the summary operating results for Addison, which are reported as a discontinued operation:

(in thousands)	Year ended December 31, 2004	For the 275 day period from January 1, 2005 to October 2, 2005
Revenues	$85,219	$ 4,490
Costs and expenses	48,945	8,893
Income (loss) from operations	36,274	(4,403)
Gain on disposition	—	175,717
Income tax expense	10,358	49,282
Income from discontinued operations, net of income tax	$25,916	$122,032

Addison Energy Inc. dividend

On February 9, 2005 Addison made an earnings and profits dividend (as calculated under U.S. tax law) to EXCO in an amount of Cdn. $74.5 million (U.S. $59.6 million). This dividend was funded by Addison by an additional drawdown on its bank credit facility. The dividend was subject to Canadian tax withholding of 5% or Cdn. $3.7 million (U.S. $3.0 million), which amount has been included in the 2004 tax provision.

Presentation on financial statements

Addison's financial position and results of operations have been reported as discontinued operations. We have revised our consolidated statements of cash flows for the year ended December 31, 2004 to separately disclose the operating, investing, and financing sections of the cash flows attributable to Addison's operations. We had previously reported the income or loss from discontinued operations as a component of net cash provided by or used in operating activities of discontinued operations.

6. 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 sale of Addison, that occurred during 2005

During the 275 day period from January 1, 2005 to October 2, 2005, we completed seven oil and natural gas property acquisitions. The total purchase price for the acquisitions was approximately $102.3 million, funded with borrowings under our U.S. credit agreement and from surplus cash. In addition, we acquired a small natural gas gathering system for $0.7 million as part of one of the acquisitions.

During the 275 day period from January 1, 2005 to October 2, 2005, we completed seven sales of oil and natural gas properties. As of January 1, 2005, estimated total Proved Reserves net to our interest from these properties included approximately 0.3 Mmbbls of oil and NGLs and 18.4 Bcf of natural gas. The total sales proceeds we received were approximately $45.4 million. During the year ended December 31, 2004, we recorded revenue of approximately $5.5 million and oil and natural gas production costs of approximately $1.2 million on these properties. During the 275 day period from January 1, 2005 to October 2, 2005, we recorded revenues of approximately $3.7 million and oil and natural gas production costs of approximately $1.2 million on these properties through the date of their respective dispositions.

During the 90 day period from October 3, 2005 to December 31, 2005, we did not complete any acquisitions or dispositions of oil and natural gas properties.

Transactions, other than the acquisition of North Coast, that occurred during 2004

During the year ended December 31, 2004, we completed six oil and natural gas property acquisitions in the United States. The total purchase price, after contractual adjustments, for the acquisitions was approximately $88.4 million funded with borrowings under our U.S. credit agreement and from surplus cash.

During the year ended December 31, 2004, we completed 21 sales of oil and natural gas properties in the United States. The total sales proceeds we received were approximately $51.9 million.

Pro forma financial information has not been provided because the acquisitions and dispositions were not material.

7. Derivative financial instruments

The following table sets forth our oil and natural gas derivatives as of December 31, 2006. The fair values at December 31, 2006 are estimated from quotes from the counterparties and represent the amount that we would expect to receive or pay to terminate the contracts at December 31, 2006. 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.

	Volume Mmbtus/Bbls	Weighted Average Strike Price per Mmbtu/Bbl	Fair Value at December 31, 2006
	(In thousands, except prices and differentials)		
Natural Gas:			
Swaps:			
2007	47,790	$ 8.73	$82,659
2008	43,140	8.63	23,237
2009	25,705	8.02	3,943
2010	6,985	6.63	(4,664)
2011	1,825	4.51	(3,673)
2012	1,830	4.51	(2,929)
2013	1,825	4.51	(2,639)
Total Natural Gas	129,100		95,934
Oil:			
Swaps:			
2007	734	69.52	3,234
2008	327	62.67	(1,455)
2009	120	60.80	(670)
2010	108	59.85	(605)
Total Oil	1,289		504
Total Oil and Natural Gas			$96,438

At December 31, 2006, the average forward NYMEX oil prices per Bbl for calendar 2007 and 2008 were $65.02 and $67.50, respectively, and the average forward NYMEX natural gas prices per Mmbtu for calendar 2007 and 2008 were $6.97 and $8.06, respectively.

During the 275 day period from January 1, 2005 to October 2, 2005, we canceled several of our commodity price risk management contracts upon the payment of $67.6 million to our counterparties, of which $15.0 million was related to the sale of Addison. We also entered into new commodity price risk management contracts at higher prices.

8. Long-term debt and interim bank loan

(in thousands)	December 31, 2005	December 31, 2006
Short-term debt:		
Interim bank loan	$350,000	$ —
Current portion of long-term debt	—	6,500
	$350,000	$ 6,500
Long term debt:		
EXCO credit agreements	$ 1	$ 339,000
EPOP Revolving Credit Facility	—	643,500
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	17,081	14,113
Total	$461,802	$2,081,653

Credit agreements

Interim bank loan

In order to fund the Equity Buyout on October 3, 2005, Holdings II borrowed $350.0 million in interim debt financing under a credit agreement dated October 3, 2006 with JP Morgan. The loan was collateralized by a first priority lien on all of Holdings II common stock. The maturity date of the loan was July 3, 2006, with an interest rate of 10%. The loan agreement contained representations and warranties, covenants and conditions usual for a transaction of this type. Covenants contained in the loan include, among other things, restrictions on the incurrence of indebtedness, the payment dividends, redemption of capital stock and making of certain investments, sales of assets and subsidiary stock, entering into sale and leaseback transactions, entering into agreements that restrict the payment of dividends by subsidiaries, or the repayment of intercompany loans and advances, entering into affiliate transactions, entering into mergers, consolidations and sales of substantially all of our assets, amending material debt instruments, and certain other activities.

On February 14, 2006, upon closing of the initial public offering (IPO), the interim bank loan, together with accrued interest was paid in full.

EXCO Credit Agreement

On March 17, 2006, EXCO Resources, Inc. and certain of its subsidiaries entered into an amended and restated credit agreement, or our credit agreement, with certain lenders, JPMorgan Chase Bank, N.A., as administrative agent, and J.P. Morgan Securities Inc., as sole bookrunner and lead arranger. This amendment established a new borrowing base of $750.0 million under our credit agreement reflecting the addition of the assets of TXOK. TXOK and its subsidiaries became guarantors of our credit agreement. The amendment also provided for an extension of our credit agreement maturity date to December 31, 2010. The borrowing base is redetermined each November 1 and May 1, beginning November 1, 2006. Our borrowing base is determined based on a number of factors including commodity prices. We use derivative financial instruments to lessen the impact of volatility in commodity prices. Financial covenants under the amended credit agreement require that we:

- maintain a consolidated current ratio (as defined under our credit agreement) of at least 1.0 to 1.0 at the end of any fiscal quarter; and

- not permit our ratio of consolidated indebtedness to consolidated EBITDAX (as defined under our credit agreement) to be greater than 3.5 to 1.0 at the end of each fiscal quarter.

Borrowings under our credit agreement are collateralized by a first lien mortgage providing a security interest in 90% of our oil and natural gas properties including TXOK's Oklahoma properties and North Coast Energy, Inc. and their respective subsidiaries. Our borrowings are collateralized by a first lien mortgage providing a security interest in the value of our Proved Reserves which is at least 125% of the aggregate commitment. The aggregate commitment is the lesser of (i) $1.25 billion and (ii) the borrowing base, however, the initial aggregate commitment was $300.0 million. This aggregate commitment increased to $500.0 million on May 11, 2006, was reduced to $400.0 million on October 2, 2006, and was increased back to $500.0 million on February 2, 2007.

At our option, borrowings under our credit agreement accrue interest at one of the following rates:

- the sum of (i) the greatest of the administrative agent's prime rate, the base CD rate plus 1.0% or the federal funds effective rate plus 0.50% and (ii) an applicable margin, which ranges from 0.0% up to 0.75% depending on our borrowing usage; or
- the sum of (i) LIBOR multiplied by the statutory reserve rate and (ii) an applicable margin, which ranges from 1.0% up to 1.75% depending on our borrowing usage.

We typically elect to borrow funds using the LIBOR interest rate option described above. At December 31, 2005 and 2006, the six month LIBOR rates were 4.70% and 5.37% which would result in interest rates of approximately 5.95% and 6.62%, respectively, on any new indebtedness we may incur under the credit agreement. At December 31, 2005 and 2006, we had $1,000 and $339.0 million respectively, of outstanding indebtedness under our credit agreement.

Additionally, the credit agreement contains a number of other covenants regarding our liquidity and capital resources, including restrictions on our ability to incur additional indebtedness, restrictions on our ability to pledge assets, and a prohibition on the payment of dividends on our common stock. As of December 31, 2006, we were in compliance with the covenants contained in our credit agreement.

In connection with the contribution by EXCO Resources to EXCO Partners of EXCO Resources' East Texas assets, EXCO Resources entered into an amendment to its credit agreement ("First Amendment"). The First Amendment generally consents to and facilitates the contribution of the East Texas assets to EXCO Partners and provides that EXCO Partners, its subsidiaries and its general partners, all of which are subsidiaries of EXCO are unrestricted subsidiaries under our credit agreement, are not subject to the terms thereof and are no longer guarantors thereof. In addition, the assets contributed by EXCO Resources were released from the mortgages securing the credit agreement. Moreover, the assets of EXCO Partners and its subsidiaries have not been pledged under our credit agreement and none of EXCO Partners or the other unrestricted subsidiaries have guaranteed our credit agreement. The First Amendment also provides that the borrowing base under the credit agreement shall be reduced to $600.0 million, with an aggregate commitment of $400.0 million (increased back to $500.0 million on February 2, 2007). The First Amendment also revises the covenants regarding the format of the financial statements to be delivered by EXCO Resources and consents to the contingent equity contribution obligation described below under "EXCO Resources Equity Contribution Agreement" subject to certain conditions. The First Amendment also amends certain covenants to address the relationship with EXCO Partners. Prior to any public offering by EXCO Partners, EXCO Resources may not permit the subsidiaries through which EXCO Resources owns the equity of EXCO Partners to incur any indebtedness or incur any lien. Prior to any public offering by EXCO Partners, EXCO Resources is required to own 100% of the equity of EXCO Partners. As of February 28, 2007, $407.0 million of indebtedness was outstanding under our credit agreement and we had $91.5 million of availability under our credit agreement. Our consolidated debt as of February 28, 2007, which includes EPOP's debt, our credit facility and 7¼% senior notes totals $2.2 billion. The debt incurred in the Winchester acquisition is more fully described below. We are in compliance with the financial covenants of the EXCO Credit Agreement as of December 31, 2006.

EPOP Revolving Credit Facility

To finance the Winchester acquisition and the $150.0 million payment to EXCO Resources for its East Texas assets, EXCO Partners' wholly-owned subsidiary, EPOP, entered into a Senior Revolving Credit Agreement, or EPOP Revolving Credit Facility dated October 2, 2006, with a group of lenders led by JPMorgan Chase Bank, N.A. The EPOP Revolving Credit Facility has a face amount of $750.0 million with an initial borrowing base of $750.0 million and an initial conforming borrowing base of $650.0 million. The conforming borrowing base is the amount of borrowings upon which interest is computed on a lower premium to LIBOR than borrowings which exceed the conforming borrowing base. The borrowing base must be conforming by April 1, 2007. The EPOP Revolving Credit Facility 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. We executed an amendment dated effective as of December 31, 2006, the EPOP Revolver First Amendment, which amends certain financial covenants contained in the EPOP Revolving Credit Facility. The EPOP Revolver Amendment was sought due to our inability to comply with the leverage ratio and interest coverage ratio tests, as defined below, as of December 31, 2006. The original financial covenant ratios were negotiated assuming a more accelerated drilling program, which would have resulted in higher forecasted production. In addition, interest expense attributable to the EPOP Senior Term Credit Agreement was higher than originally forecast as the final negotiated interest rate exceeded our initial estimates when the covenants were being negotiated. Management and the lenders believe these revised covenants are more consistent with the actual operational activities contemplated at EPOP during 2007. As amended, the EPOP Revolving Credit Facility contains the following financial covenants:

- EPOP's Consolidated Current Ratio (as defined) as of the end of any fiscal quarter ending after September 30, 2006 is not permitted to be less than 1.00 to 1.00. The EPOP Revolver Amendment did not revise this covenant.
- EPOP's ratio of (A) Consolidated Funded Indebtedness (as defined) as of the end of a fiscal quarter to (B) Consolidated EBITDAX (as defined) shall not be greater than:
    - 6.00 to 1.00 (increased from 5.00 to 1.00) for the quarter ending December 31, 2006. For purposes of the December 31, 2006 Consolidated EBITDAX, the December 31, 2006 quarter shall be multiplied by four (4);
    - 5.50 to 1.00 (increased from 4.00 to 1.00) for the first and second quarters of 2007 (Consolidated EBITDAX calculated using a defined trailing period multiplied by a fraction);
    - 5.50 to 1.00 (increased from 4.00 to 1.00) for the quarter ended September 30, 2007 (with Consolidated EBITDAX calculated using, for this quarter and all subsequent quarters, the trailing four quarter period ending on such date);
    - 5.25 to 1.00 (increased from 4.00 to 1.00) for the quarter ended December 31, 2007, and
    - 4.00 to 1.00 (unchanged) for any quarter ending on or after March 31, 2008.
- EPOP will not permit its ratio of Consolidated EBITDAX to Consolidated Interest Expenses (as defined) to be less than:
    - 1.50 to 1.00 (lowered from 2.50 to 1.00) as of the quarter ended December 31, 2006 (Consolidated EBITDAX and Consolidated Interest Expenses for such quarter to be multiplied by four);

    - 1.75 to 1.00 (lowered from 2.50 to 1.00) for the first and second quarters of 2007 (Consolidated EBITDAX and Consolidated Interest Expenses calculated using a defined trailing period multiplied by a fraction);
    - 1.75 to 1.00 (lowered from 2.50 to 1.00) for the quarter ended September 30, 2007 (with Consolidated EBITDAX and Consolidated Interest Expenses calculated using, for this quarter and all subsequent quarters, the trailing four quarter period ending on such date);
    - 2.00 to 1.00 (lowered from 2.50 to 1.00) as of the quarter ended December 31, 2007, and
    - 2.50 to 1.00 (unchanged) for any quarter ending on or after March 31, 2008.
- Finally, EPOP will not permit its ratio of net present value (calculated pursuant to the terms of the EPOP Revolving Credit Facility) to Consolidated Funding Indebtedness (as defined) to be less than (i) 1.15 to 1.00 (unchanged) determined as of December 31, 2006 or (ii)1.25 to 1.00 (unchanged) determined as of each succeeding June 30 and December 31.

The EPOP Revolving Credit Facility, as amended, contains representations, warranties, covenants, events of default, and indemnities customary for agreements of this type. The EPOP Revolving Credit Facility matures four years from the closing date and has an initial drawn interest rate of LIBOR + 175 basis points ("bps") and an undrawn commitment fee of 37.5 bps on the first $650.0 million of the EPOP Revolving Credit Facility. To the extent usage exceeds the initial conforming borrowing base, the EPOP Revolving Credit Facility will have an initial drawn interest rate of LIBOR + 250 bps and an undrawn commitment fee of 50 bps on the portion of the borrowings that exceed the initial conforming borrowing base. Finally, as a condition precedent to the funding of the EPOP Revolving Credit Facility, EPOP is required to hedge 75% of proved developed producing production through 2010. The repayment obligation under this facility can be accelerated upon the occurrence of an event of default including the failure to pay principal or interest, a material inaccuracy of a representation or warranty, failure to observe or perform covenants, subject to certain cure periods, bankruptcy, judgments against EPOP or any subsidiary in excess of $5.0 million or a change of control (as defined) of EPOP. The initial amount borrowed under this facility was $651.0 million at closing of the Winchester merger and the weighted average interest rate as of December 31, 2006, is 7.19%. As of February 28, 2007, $643.5 million was outstanding under this facility. We are in compliance with the financial covenants, as amended, pursuant to the EPOP Revolver First Amendment as of December 31, 2006.

EPOP Senior Term Credit Agreement

In connection with the Winchester acquisition and the EXCO Resources asset contribution, EPOP entered into the EPOP Senior Term Credit Agreement, dated October 2, 2006 (as amended and restated as of October 13, 2006), with JPMorgan Chase Bank, N.A., as administrative agent. The aggregate principal amount is $650.0 million. The EPOP Senior Term Credit Agreement is secured by a second priority lien on all of the properties securing the EPOP Revolving Credit Facility, including 100% of the stock of subsidiaries, and is guaranteed by all existing and future subsidiaries. Financial covenants governing the EPOP Senior Term Credit Agreement include the same net present value ratio contained in the EPOP Revolving Credit Facility, a Leverage Ratio computed similarly to the covenant contained in the EPOP Revolving Credit Facility that cannot exceed 5.50 to 1.00 for applicable periods, and an Interest Coverage Ratio that cannot be less than 2.00 to 1.00 for any applicable period. The debt covenant tests for the EPOP Senior Term Credit Agreement begin with the quarter ended March 31, 2007. In addition, EPOP cannot make Capital Expenditures (as defined) exceeding $125.0 million in any fiscal year. The EPOP Senior Term Credit Agreement contains representations, warranties, covenants, events of default and indemnities customary for agreements of this type. The EPOP Senior Term Credit Agreement has an interest rate of LIBOR + 600 bps, with 25 bps step-ups on October 2, 2007 and January 2, 2008, and a total cap of LIBOR + 650 bps. Additionally, the EPOP Senior Term Credit Agreement matures five years from the closing date, requires payments of principle at 1% per year, with the balance of unpaid principle due at maturity. Upon an initial public offering by EXCO Partners, EPOP shall prepay the principal outstanding (plus accrued interest) under the EPOP Senior Term Credit Agreement at par plus an applicable premium. Commencing with the fiscal year ended December 31, 2007, and each year thereafter, EPOP must apply 100% of its Excess Cash Flow (as defined in the EPOP Senior Term Credit Agreement) toward prepayment at par of the EPOP Senior Term Credit Agreement. Such payments shall be made no later than the later of April 15 or five business days following delivery of the annual financial statements required under the EPOP Senior Term Credit Agreement. Any principal payment prior to the first anniversary, other than the mandatory cash flow and amortization prepayments described above, must be paid at 102% of the principal amount and after the first anniversary date to and including the second anniversary at 101% of par. Thereafter, any prepayments are at par. The repayment obligation under this facility can be accelerated upon the occurrence of an event of default including the failure to pay principal or interest, a material inaccuracy of a representation or warranty, failure to observe or perform covenants, subject to certain cure periods, bankruptcy, judgments against EPOP or any subsidiary in excess of $5.0 million or a change of control (as defined) of EPOP.

EXCO Resources Equity Contribution Agreement

In connection with the arrangement of the EPOP Senior Term Credit Agreement, the lenders required EXCO Resources to enter into an Equity Contribution Agreement, dated October 2, 2006, and amended and restated on October 4, 2006 and October 13, 2006 (as amended and restated, the "ECA"). The ECA generally provides that on the date 18 months from October 2, 2006 (Equity Contribution Date), EXCO Resources will make a cash common equity contribution to EPOP in an amount equal to the lesser of (i) $150.0 million or (ii) the aggregate amount then outstanding under the EPOP Senior Term Credit Agreement; provided, that in no event can this obligation exceed during the term of the ECA the maximum amount that EXCO Resources could contribute under the terms of the Indenture governing its senior notes. Alternatively, EXCO Resources can cause EXCO Partners to make the equity contribution to EPOP in the amount of $150.0 million to satisfy this obligation. In lieu of requiring the equity contribution, the holders of at least 66⅔% of the aggregate principal amount of the loans outstanding under the EPOP Senior Term Credit Agreement can elect at the Equity Contribution Date to require EPOP and its subsidiaries to become "Restricted Subsidiaries" under the credit agreement and require EXCO Resources to provide, and cause all then restricted subsidiaries as defined and constituted under the credit agreement to provide, guarantees and collateral in respect of the EPOP Senior Term Credit Agreement on terms substantially consistent with the guarantees and collateral provided under its credit agreement. This requirement is subject to compliance with the credit agreement. Any cash so contributed shall be used by EPOP to prepay loans under the EPOP Senior Term Credit Agreement. EXCO Resources is prohibited from making restricted payments (as defined in the Indenture) that would constitute a utilization of the Indenture restricted payment baskets, other than restricted payments not to exceed $5.0 million In addition, EXCO Resources has covenanted to redeem or defease its senior notes if the Indenture would not permit the equity contribution or the lenders' election to cause EXCO Resources to designate EPOP and its subsidiaries as restricted subsidiaries under the credit agreement (subject to certain restrictions on the indebtedness that may be incurred for any such redemption or defeasance if the election to cause the designation of EPOP as a restricted subsidiary is chosen). The ECA will terminate upon payment in full of the EPOP Senior Term Credit Agreement.

7¼% senior notes due January 15, 2011

On January 20, 2004, EXCO completed the private placement of $350.0 million aggregate principal amount of 7¼% senior notes due January 15, 2011 pursuant to Rule 144A and Regulation S under the Securities Act of 1933 (Securities Act) at a price of 100% of the principal amount. The net proceeds of the offering were used to acquire North Coast, pay down debt under our credit facilities and North Coast's credit facility, repay our senior term loan in full and pay fees and expenses associated with those transactions.

Concurrent with the issuance of the senior notes, we wrote off $0.9 million of costs incurred in January 2004 to secure interim loan financing which was not utilized upon issuance of the senior notes and deferred financing costs of approximately $0.7 million related to the senior term loan, which was retired with the proceeds of the senior notes. These amounts are reflected in the consolidated statements of operations as interest expense.

On April 13, 2004, EXCO completed a private placement of an additional $100.0 million aggregate principal amount of the senior notes pursuant to Rule 144A, having the same terms and governed by the same Indenture as the notes issued on January 20, 2004. The notes issued on April 13, 2004 were issued at a price of 103.25% of the principal amount plus interest accrued since January 20, 2004. The net proceeds of the April 13, 2004 offering were used to repay substantially all of our outstanding indebtedness under our Canadian credit agreement and pay fees and expenses associated therewith.

On May 28, 2004, EXCO concluded an exchange offer of $450.0 million aggregate principal amount of our senior notes, which were privately placed in January and April 2004, for $450.0 million aggregate principal amount of our senior notes that have been registered under the Securities Act. Holders of all but $0.3 million of the senior notes elected to accept our exchange offer.

The Equity Buyout was a change of control under the Indenture governing the senior notes. As a result of this change of control and also in connection with the sale of Addison, on November 2, 2005, we commenced an offer to the holders of senior notes to repurchase up to $120.6 million of senior notes at 100% of the principal amount plus accrued and unpaid interest of the notes pursuant to the Indenture. Simultaneously therewith, we commenced an offer to repurchase all outstanding senior notes at 101% of the principal amount plus accrued and unpaid interest in connection with the change in control provision contained in the Indenture as a result of the Equity Buyout. Holders of $5.3 million in aggregate principal amount of the senior notes were tendered to and purchased by us in December 2005 as a result of these offers for total consideration of $5.5 million including accrued plus unpaid interest and the applicable premium. As a result of the repurchase of these senior notes, we recognized a gain upon the early extinguishment of these notes in the amount of approximately $151,000 during the 90 day period from October 3, 2005 to December 31, 2005 which has been reflected in other income on our consolidated statements of operations. Upon completion of the offer to repurchase related to the Addison sale, the second lien security interest on $120.6 million of the proceeds from the sale and the general restrictions under the Indenture on the entire proceeds was terminated.

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, EXCO 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 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 notes.

As part of the "pushdown accounting" resulting from the Equity Buyout, the senior notes were recorded at their fair value of $468.0 million on October 3, 2005. The resulting premium of $18.0 million in excess of the aggregate principal amount is being amortized over the remaining life of the senior notes. The unamortized premium was $14.1 million at December 31, 2006. The purchase of the $5.3 million in aggregate principal amount of senior notes tendered to us as discussed above reduced the premium to be amortized by approximately $202,000.

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.

The estimated fair value of our senior notes at December 31, 2006 was $453.6 million as compared to the carrying amount of $458.8 million (including $14.1 million of unamortized premium). The fair value of the senior notes is estimated based on quoted market prices for the senior notes.

Following is the principal maturity schedule for the debt outstanding as of December 31, 2006 (in thousands):

	Amount
2007	$ 6,500
2008	6,435
2009	6,371
2010	988,807
2011	1,069,107
Thereafter	—
Total	$2,077,220

9. 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.

10. Commitments and contingencies

We lease our offices and certain equipment. Our rental expenses were approximately $0.6 million, $0.6 million, $0.2 million and $1.7 million for the year ended December 31, 2004, 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 year ended December 31, 2006, respectively. Our future minimum rental payments under operating leases with remaining noncancellable lease terms at December 31, 2006, are as follows (in thousands):

	Amount
2007	$ 5,834
2008	5,198
2009	4,679
2010	4,618
2011	1,620
Thereafter	2,235
Total	$24,184

We regularly enter into agreements with contract drilling companies which commit us to utilize, or to pay for if not utilized, the use of drilling rigs in east Texas. As of December 31, 2006, the minimum amount that we are obligated to pay under these contracts is $78.6 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 materially adverse effect on our results of operations or financial condition.

11. Employee benefit plans

We sponsor 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, $0.4 million, $95,000 and $1.1 million for the year ended December 31, 2004, 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 year ended December 31, 2006, respectively, have been included as general and administrative expense.

12. Bonus retention program

Prior to entering into the Equity Buyout, Holdings established a bonus retention program in 2003 to provide an incentive for the employee stockholders of Holdings 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. For the year ended December 31, 2004, we included approximately $1.4 million in general and administrative expense and $0.4 million in income from operations of discontinued operations related to this program.

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 Addison, the Addison 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.

13. Earnings per share

The following table presents basic and diluted earnings (loss) per share for the year ended December 31, 2004, 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 year ended December 31, 2006 (in thousands, except per share amounts):

	Predecessor		Successor	
	Year ended December 31, 2004	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
Basic earnings per share:				
Income (loss) from continuing operations	$ (19,903)	$(137,216)	$16,350	$138,954
Income from discontinued operations	25,916	122,032	—	—
Net income	$ 6,013	$ (15,184)	$16,350	$138,954
Shares:				
Weighted average number of common shares outstanding	115,947	116,504	47,222	96,727
Basic earnings (loss) per share:				
Continuing operations	$ (0.17)	$ (1.18)	$ 0.35	$ 1.44
Discontinued operations	0.22	1.05	—	—
Total basic earnings per share	$ 0.05	$ (0.13)	$ 0.35	$ 1.44
Diluted earnings per share:				
Income (loss) from continuing operations	$ (19,903)	$(137,216)	$16,350	$138,954
Income from discontinued operations	25,916	122,032	—	—
Net income	$ 6,013	$ (15,184)	$16,350	$138,954
Shares:				
Weighted average number of common shares outstanding	115,947	116,504	47,222	96,727
Dilutive effect of stock options	—	—	—	1,726
Weighted average common shares and common stock equivalents	115,947	116,504	47,222	98,453
Diluted earnings (loss) per share:				
Continuing operations	$ (0.17)	$ (1.18)	$ 0.35	$ 1.41
Discontinued operations	0.22	1.05	—	—
Total diluted earnings per share	$ 0.05	$ (0.13)	$ 0.35	$ 1.41

As a result of the loss from continuing operations for the year ended December 31, 2004 and the 275 day period from January 1, 2005 to October 2, 2005, the potential common stock equivalents from the assumed conversion of stock options of 5,097,369 and 8,801,351, respectively, have been excluded from the diluted EPS calculation. For financial accounting purposes, the Class B shares of Holdings for the year ended December 31, 2004 and 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.

14. Stock transactions

Stock options

As discussed in "Note 2. Summary of significant accounting policies", certain of our employees were granted Holdings stock options under the Holdings Plan. The following table summarizes Holdings stock option activity under the Holdings Plan, which were canceled upon consummation of the Equity Buyout:

	Stock Options	Weighted Average Exercise Price Per Share
Options outstanding at December 31, 2004	8,801,354	$3.00
Granted	194,630	$3.57
Expired or canceled	324,078	$3.00
Exercised	—	—
Cash-out in connection with equity buyout	8,671,906	$3.01
Options exerciseable at October 3, 2005	—	$ —

All of the issued and outstanding Holdings stock options as of October 3, 2005 were purchased by Holdings 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.

The 2005 Incentive Plan provides for the granting of options to purchase up to 10,000,000 shares of EXCO's common stock. The options expire ten years following the date of grant and have a weighted average remaining life of 9.19 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. As of December 31, 2006, there were 1,574,475 shares available to be granted under the Plan.

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
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	9.19	$54,505
Options exercisable at December 31, 2006	3,179,474	$ 9.33	9.04	$24,116

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

The following summarizes the status of the non-vested stock options as of December 31, 2006 and changes for the year ended December 31, 2006:

	Number of shares	Weighted average grant date fair value
Nonvested January 1, 2006	3,728,962	$2.29
Granted	3,615,700	4.75
Forfeitures	(163,250)	2.79
Vested	(2,093,513)	3.35
Nonvested at December 31, 2006	5,087,899	$3.59

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
Expected life	4 years	4 years
Risk-free rate of return	4.22%	4.22% - 5.13%
Volatility	30.40%	30.40 % - 35.58%
Dividend yield	0%	0%

As required by SFAS 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. Volatility was determined based on the weighted average of historical volatility of the common stock of the Predecessor for .25 years and the daily closing prices from five comparable public companies. Total share-based compensation for the 90 day period from October 3, 2005 to December 31, 2005 and the year ended December 31, 2006 was $3.2 million and $7.9 million, of which $2.2 million and $6.5 million is included in general and administrative expense and $1.0 million and $1.4 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." Total share-based compensation to be recognized on unvested awards is $15.5 million over a weighted average period of 2.40 years as of December 31, 2006.

As discussed in "Note 1. Organization," 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.

15. Income taxes

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

(in thousands)	Predecessor		Successor	
	Year ended December 31, 2004	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
Current:				
U.S.				
Federal	$ —	$ (3,563)	$ (7,020)	$ —
State	1,445	(668)	(1,315)	—
Total current income tax (benefit)	1,445	(4,231)	(8,335)	—
Deferred:				
U.S.				
Federal	4,681	(49,881)	12,949	80,697
State	(91)	(9,586)	3,017	8,704
Canadian	(909)	—	—	—
Total deferred income tax (benefit)	3,681	(59,467)	15,966	89,401
Total income tax (benefit)	$5,126	$(63,698)	$ 7,631	$89,401

We have net operating loss carryforwards (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. We estimate that approximately $7.9 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, 2006 is approximately $129.3 million.

Prior to the fourth quarter of 2004, we had not provided for any U.S. deferred income taxes on the undistributed earnings of Addison, our former Canadian subsidiary, based upon the determination that those earnings would be indefinitely reinvested in Canada. On October 22, 2004, the President signed the American Jobs Creation Act of 2004 (the Act). The Act created a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85% dividends received deduction for certain dividends from controlled foreign corporations. In February 2005, we repatriated Cdn. $74.5 million (U.S. $59.6 million) in an extraordinary dividend, as defined in the Act, from Addison. Accordingly, we recognized a tax liability of $8.2 million as of December 31, 2004 related to the extraordinary dividend. This dividend represented a substantial portion of the undistributed earnings of Addison, based upon its earnings and profits as determined under U.S. federal income tax law, as of December 31, 2004. As a result of certain technical corrections to the Act, we recognized a benefit of $2.1 million in our current income taxes during the 275 day period from January 1, 2005 to October 2, 2005 related to this dividend. This additional $2.1 million benefit has been recognized as a component of taxes from continuing operations pursuant to SFAS No. 109, "Accounting for Income Taxes" (SFAS No. 109) and Emerging Issues Task Force 93-13, "Effect of a Retroactive Change in Enacted Tax Rates That is Included in Income from Continuing Operations" (EITF 93-13), which require that the tax effect of a change in enacted tax rates be allocated to continuing operations without regard to whether the item giving rise to the effect is a component of discontinued operations. 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 tax rate on our existing deferred balances in the second quarter of 2006. Our deferred income tax related to the Texas Margin tax is $0.9 million at December 31, 2006.

For the year ended December 31, 2004, we recognized a deferred income tax benefit of approximately $0.9 million related to Canadian legislation which became effective in May 2004 to phase in reduced income tax rates and allow for deductibility of crown royalties. This amount has been reflected as an income tax benefit in continuing operations pursuant to the provisions of SFAS No. 109 and EITF 93-13 as discussed above.

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, 2005	December 31, 2006
Current deferred tax assets (liabilities):		
Basis difference in fair value of derivative financial instruments	$ 26,605	$ (32,639)
Other	3,363	—
Total current deferred tax assets (liabilities)	$ 29,968	$ (32,639)
Long-term deferred tax assets:		
Net operating loss carryforwards—U.S.	$ 1,879	$ 48,654
Basis difference in fair value of derivative financial instruments	34,300	32,684
Purchase accounting adjustment to bond premium	5,456	9,511
Share-based compensation	437	1,234
Other	3	118
Total long-term deferred tax assets	42,075	92,201
Deferred tax liabilities:		
Book basis of oil and natural gas properties in excess of tax basis—U.S.	(176,677)	(258,337)
Taxes on undistributed earnings of foreign subsidiary—U.S.	(310)	—
Total deferred liabilities	(176,987)	(258,337)
Net noncurrent deferred tax liabilities	$(134,912)	$(166,136)

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 year ended December 31, 2004, 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 year ended December 31, 2006 is presented in the following table:

	Predecessor		Successor	
(in thousands)	Year ended December 31, 2004	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
United States federal income taxes (benefit) at statutory rate of 35%	$(5,120)	$(70,293)	$ 8,393	$79,925
Increases (reductions) resulting from:				
Undistributed earnings of foreign subsidiary	8,237	—	—	—
Foreign tax items	—	644	(2,996)	—
Change in Canadian tax rates	(909)	—	—	—
Change in U.S. tax law related to Canadian dividend	—	(2,075)	—	—
Adjustments to the valuation allowance	—	—	—	—
Non-deductible compensation	—	15,432	604	1,420
Non-deductible intercompany foreign interest expense	1,840	—	—	—
State taxes net of federal benefit	880	(6,665)	1,095	8,704
Other	198	(741)	535	(648)
Total income tax provision	$ 5,126	$(63,698)	$ 7,631	$89,401

16. Related party transactions

TXOK acquisition

On September 16, 2005, Holdings (formerly Holdings II) incorporated TXOK Acquisition, Inc. (TXOK), a Delaware corporation with a $1,000 investment in TXOK common stock. TXOK was formed to acquire (i) all of the issued and outstanding shares of common stock of ONEOK Energy Resources Company (ONEOK Energy) and (ii) all of the issued and outstanding membership interests of ONEOK Energy Resources Holdings, LLC (ONEOK Energy LLC) (collectively ONEOK Energy). ONEOK Energy was wholly-owned by ONEOK, Inc., a Tulsa-based public utility company.

The ONEOK Energy acquisition closed on September 27, 2005. The purchase price paid at closing, based upon adjustments as of that date, was $633.0 million, net of contractual adjustments. Effective upon closing, ONEOK Energy and ONEOK Energy LLC became wholly-owned subsidiaries of TXOK.

TXOK funded the ONEOK Energy acquisition with (i) $20.0 million in private debt financing, $15.0 million of which was provided by Mr. Boone Pickens, one of our directors; (ii) the issuance of $150.0 million of TXOK preferred stock to BP EXCO Holdings LP, an entity controlled by Mr. Pickens; (iii) the TXOK credit facility, with an initial borrowing base of $325.0 million, of which approximately $308.8 million was drawn at the closing of the ONEOK Energy acquisition; and (iv) the TXOK second lien term loan facility of $200.0 million. Neither Holdings nor EXCO Resources were an obligor or guarantor with respect to these financings; however, Holdings (formerly Holdings II) pledged its stock in TXOK as collateral security for payment of the TXOK credit facility and the TXOK term loan.

On October 7, 2005 Holdings made an additional $20.0 million investment in TXOK. Holdings' additional investment was partially funded by an advance of $4.0 million from EXCO Resources. TXOK used these proceeds to repay the $20.0 million in private debt financing described in (i) above. Following the Equity Buyout, Holdings made payments on behalf of EXCO Resources of approximately $10.0 million, including bank fees associated with the interim bank loan that was pushed down to us. As of December 31, 2005, we had a net liability to Holdings of $6.1 million.

On February 14, 2006, 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.

Effective October 15, 2005, we entered into an agreement with TXOK to manage TXOK's business affairs. Mr. Pickens controlled TXOK through BP EXCO Holdings LP's ownership of the TXOK preferred stock. The agreement provided that we would provide TXOK with general management, treasury, finance, legal, audit, tax, information technology, and payroll and benefit administration services. TXOK agreed to reimburse us on a monthly basis for the total amount of compensation, taxes and benefits we provide to employees providing services to TXOK. TXOK also agreed to pay us $25,000 per month for the additional services that we provide, as well as reimbursement of all costs directly related to the operations of TXOK. We hired 57 people who were formerly employed by ONEOK and historically worked on these assets. TXOK reimbursed us for all compensation expenses of these employees. At December 31, 2005, we had approximately $2.6 million reflected in accounts receivable-related parties on our consolidated balance sheet as due to us from TXOK of which $0.3 million was to reimburse us for accrued, but unpaid, stock option compensation expense for our employees who are assigned to manage TXOK's business. On February 14, 2006, TXOK became our wholly-owned subsidiary and the accounts under the related party arrangements were settled.

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 reimbursed use of the aircraft is restricted to company business. Such use must be approved in advance by Resources' President and 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 less than market rate for similar aircraft.

We reimburse DHM Aviation, LLC at a rate of $3,600 per hour, including fuel surcharges, for use of the aircraft. During the year ended December 31, 2004, we paid DHM Aviation, LLC $0.5 million for use of the 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 were $0.4 million for use of the aircraft. During 2004, we were reimbursed a total of $93,000 of the aircraft fees by the underwriters of our senior notes offering.

Equity Buyout

On October 3, 2005, Holdings II acquired all the capital stock of EXCO Holdings and subsequently merged into EXCO Holdings. Upon its formation, Holdings II issued 3,333,330 shares of common stock to its founders for $0.01 per share. This group of founders included Mr. Douglas H. Miller, who purchased 1,655,000 shares, Mr. Stephen F. Smith, who purchased 333,330 shares, Dr. J. Douglas Ramsey, who purchased 166,670 shares (these shares were issued to a limited partnership in which Dr. Ramsey owns a 98.0% limited partnership interest), and Mr. Harold L. Hickey, who purchased 166,670 shares, as well as a number of our employees. Each of these persons and many of our employees also exchanged shares of EXCO Holdings common stock for Holdings II common stock or purchased additional shares of Holdings II common stock for cash.

Suite

The Company maintains a suite at the American Airlines Center in Dallas, Texas. The Company shares the suite with and is 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.

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.

17. Concentration of credit risk

During 2005 and 2006, sales of natural gas to an industrial customer and an interstate pipeline accounted for 10.1% and 11.6%, respectively, of our total oil and natural gas revenues. During 2004, sales of natural gas to an industrial customer accounted for 10.6% of our 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.

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

We follow Statement of Financial Accounting Standards No. 131, "Disclosures About Segments of an Enterprise and Related Information" (SFAS No. 131). We have operations in only one industry segment, that being the oil and natural gas exploration and production industry. In prior periods, the Company provided geographic segment information for the following regions within the United States: EXCO, excluding Appalachia, and Appalachia. Effective in the fourth quarter of 2006, we no longer present separate financial information for geographic regions within the United States as we have aggregated these regions into one reportable segment. As a result, the prior period segment information has been deleted.

19. Subsequent events

On December 29, 2006, we announced an agreement with Anadarko Petroleum Corporation and Anadarko Gathering Company, or collectively Anadarko, to acquire substantially all of the oil and gas properties and related assets, or collectively the Vernon Assets, of Anadarko in the Vernon and Ansley Fields located in Jackson Parish, Louisiana through our wholly-owned subsidiary, Vernon Holdings, LLC, or Vernon, for $1.6 billion in cash. In December 2006, we deposited $80.0 million in an escrow account to be applied to the purchase price upon closing. We anticipate closing on these properties in the first quarter of 2007.

On February 2, 2007, we announced we had signed a Purchase and Sale Agreement, or the Southern Gas Purchase Agreement, with Anadarko Petroleum Corporation, Anadarko E&P Company, LP, Howell Petroleum Corporation, and Kerr-McGee Oil & Gas Onshore LP, or collectively Anadarko, to acquire substantially all of the oil and natural gas properties and related assets, of Anadarko in multiple fields located in the Mid-Continent, South Texas and Gulf Coast areas of Oklahoma and Texas. The purchase price is $860.0 million, of which, we have paid $43.0 million. We anticipate closing in the second quarter of 2007.

In conjunction with these acquisitions, we have received a revised commitment letter dated as of February 1, 2007, from J.P. Morgan Securities Inc. and JPMorgan Chase Bank, N.A. The new commitment letter provides for a senior secured revolving credit facility in the amount of $1.8 billion and a bridge loan facility in the amount of $1.1 billion, or collectively the new credit facilities. In addition, we are considering other financing alternatives, including a private placement of preferred stock.

In January 2007, we completed the sale of our producing properties and remaining undeveloped drilling locations in the Wattenberg Field area of the DJ Basin, Colorado. The transaction included substantially all of our assets in the area. The adjusted purchase price paid at closing was $131.9 million.

20. Quarterly financial data (unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2005 and 2006:

	Quarter				
	Predecessor				Successor
				2 day period from October 1, 2005 to October 2, 2005	90 day period from October 3, 2005 to December 31, 2005
(in thousands)	1st	2nd	3rd		4th
2005					
Revenues	$ (18,072)	$ 31,662	$ (52,327)	$ 1,401	$ 72,179
Operating income	(46,875)	1,387	(82,501)	(72,925)	23,981
Net income (loss) from continuing operations	$ (28,668)	$ 4,412	$ (49,723)	$ (63,237)	$ 16,350
Income (loss) from discontinued operations	120,884	1,149	—	(1)	—
Net income (loss)	$ 92,216	$ 5,561	$ (49,723)	$ (63,238)	$ 16,350
Basic earnings per share:					
Net income (loss) from continuing operations	$ (0.25)	$ 0.04	$ (0.43)	$ (0.53)	$ 0.35
Income from discontinued operations	1.04	0.01	—	—	—
Net income (loss)	$ 0.79	$ 0.05	$ (0.43)	$ (0.53)	$ 0.35
Diluted earnings per share:					
Net income (loss) from continuing operations	$ (0.25)	$ 0.04	$ (0.43)	$ (0.53)	$ 0.35
Income from discontinued operations	1.04	0.01	—	—	—
Net income (loss)	$ 0.79	$ 0.05	$ (0.43)	$ (0.53)	$ 0.35

	1st	2nd	3rd	4th
2006				
Revenues	$ 113,146	$ 117,112	$ 185,329	$ 143,862
Operating income	54,718	52,855	116,229	4,553
Net income (loss) from continuing operations	$ 37,152	$ 31,023	$ 71,745	$ (966)
Income from discontinued operations	—	—	—	—
Net income (loss)	$ 37,152	$ 31,023	$ 71,745	$ (966)
Basic earnings per share:				
Net income (loss) from continuing operations	$ 0.46	$ 0.30	$ 0.69	$ (0.01)
Income from discontinued operations	—	—	—	—
Net income (loss)	$ 0.46	$ 0.30	$ 0.69	$ (0.01)
Diluted earnings per share:				
Net income (loss) from continuing operations	$ 0.45	$ 0.29	$ 0.68	$ (0.01)
Income from discontinued operations	—	—	—	—
Net income (loss)	$ 0.45	$ 0.29	$ 0.68	$ (0.01)

21. 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. On February 14, 2006, concurrent with the closing of our IPO, TXOK and its subsidiaries became restricted subsidiaries under and guarantors of the senior notes. On May 4, 2006, PGMT became a guarantor of the senior notes. In conjunction with the formation of EXCO Partners and the Winchester acquisition on October 2, 2006, certain of our existing subsidiaries, specifically ROJO Pipeline, Inc. and those TXOK subsidiaries that hold direct or indirect interests in certain of our East Texas assets were released from their guaranties under the senior notes and are now deemed unrestricted subsidiaries thereunder. EXCO Resources itself also contributed all of its directly held East Texas assets to EXCO Partners. EXCO Partners, its direct and indirect partners, which are also subsidiaries of EXCO Resources, and all of EXCO Partners' subsidiaries are deemed unrestricted subsidiaries under the Indenture governing the senior notes and are not guarantors of the senior notes.

In connection with the formation of EXCO Partners on October 2, 2006 and the resulting contribution of EXCO's assets in East Texas, its ROJO subsidiary and the East Texas subsidiaries of TXOK (collectively, the non-guarantor subsidiaries), the consolidating balance sheet as of December 31, 2005 and the consolidating statements of operations and consolidating statements of cash flows for the year ended December 31, 2004, 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 have been restated to reflect the non-guarantor subsidiaries as if they had been non-guarantor subsidiaries for all periods presented. We have also presented the 2006 consolidating financial statements to reflect the non-guarantor status 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, 2005

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 191,499	$ 35,454	$ —	$ —	$ 226,953
Other current assets	67,650	43,589	4,333	—	115,572
Total current assets	259,149	79,043	4,333	—	342,525
Investment in TXOK Acquisition, Inc.	20,837	—	—	—	20,837
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties	49	46,385	6,687	—	53,121
Proved developed and undeveloped oil and natural gas properties	94,872	691,716	87,007	—	873,595
Allowance for depreciation, depletion and amortization	(1,650)	(9,060)	(2,571)	—	(13,281)
Oil and natural gas properties, net	93,271	729,041	91,123	—	913,435
Gas gathering assets, office and field equipment, net	1,745	30,846	680	—	33,271
Goodwill	76,786	143,220	—	—	220,006
Investments in and advances to affiliates	1,241,231	(288,867)	(83,073)	(869,291)	—
Other assets, net	—	419	—	—	419
Total assets	$1,693,019	$ 693,702	$13,063	$(869,291)	$1,530,493
Liabilities and stockholders' equity					
Current liabilities	$ 769,210	$ 50,482	$ 2,087	$(356,054)	$ 465,725
Long-term debt	461,802	—	—	—	461,802
Deferred income taxes	34,151	100,761	—	—	134,912
Other liabilities	56,974	39,634	564	—	97,172
Stockholders' equity	370,882	502,825	10,412	(513,237)	370,882
Total liabilities and stockholders' equity	$1,693,019	$ 693,702	$13,063	$(869,291)	$1,530,493

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	$ (3,031)	$ 15,786	$ 10,067	$ —	$ 22,822
Other current assets	21,040	59,494	133,354	—	213,888
Total current assets	18,009	75,280	143,421	—	236,710
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties	53,617	54,603	189,699	—	297,919
Proved developed and undeveloped oil and natural gas properties	341,694	1,085,737	1,065,432	—	2,492,863
Allowance for depreciation, depletion and amortization	(20,701)	(66,507)	(55,383)	—	(142,591)
Oil and natural gas properties, net	374,610	1,073,833	1,199,748	—	2,648,191
Gas gathering assets, office and field equipment, net	5,193	34,085	174,883	—	214,161
Deferred financing costs	946	—	14,983		15,929
Advance on probable acquisition	80,000	—	—	—	80,000
Oil and natural gas derivatives	1,868	9,522	30,079	—	41,469
Goodwill	62,776	196,952	210,349	—	470,077
Investments in and advances to affiliates	1,515,673	(336,199)	373,805	(1,553,279)	—
Other assets, net	—	488	32	—	520
Total assets	$2,059,075	$1,053,961	$2,147,300	$(1,553,279)	$3,707,057
Liabilities and stockholders' equity					
Current liabilities	$ 56,691	$ 35,266	$ 98,967	$ —	$ 190,924
Long-term debt	797,832	—	1,283,821	—	2,081,653
Deferred income taxes	14,395	151,741	—	—	166,136
Other liabilities	10,307	67,491	10,696	—	88,494
Stockholders' equity	1,179,850	799,463	753,816	(1,553,279)	1,179,850
Total liabilities and stockholders' equity	$2,059,075	$1,053,961	$2,147,300	$(1,553,279)	$3,707,057

EXCO Resources, Inc.

Consolidating statement of operations

For the year ended December 31, 2004

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas sales	$ 39,993	$98,360	$ 3,640	$ —	$141,993
Derivative financial instruments	(18,055)	(32,288)	—	—	(50,343)
Other income	4,305	877	—	(3,998)	1,184
Equity in earnings of subsidiaries	41,164	—	—	(41,164)	—
Total revenues	67,407	66,949	3,640	(45,162)	92,834
Costs and expenses:					
Oil and natural gas production	11,563	15,759	934	—	28,256
Depreciation, depletion and amortization	7,148	20,271	1,100	—	28,519
Accretion of discount on asset retirement obligations	348	446	6	—	800
General and administrative	11,603	3,288	575	—	15,466
Interest	34,432	4,136	—	(3,998)	34,570
Total costs and expenses	65,094	43,900	2,615	(3,998)	107,611
Income (loss) before income taxes	2,313	23,049	1,025	(41,164)	(14,777)
Income tax expense	504	4,622	—	—	5,126
Income before discontinued operations	1,809	18,427	1,025	(41,164)	(19,903)
Discontinued operations:					
Income from operations	5,114	—	31,160	—	36,274
Income tax expense	910	—	9,448	—	10,358
Income from discontinued operations	4,204	—	21,712	—	25,916
Net income	$ 6,013	$ 18,427	$22,737	$(41,164)	$ 6,013

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	$ 22,861	$ 96,005	$13,955	$ —	$ 132,821
Derivative financial instruments	(56,705)	(120,548)	—	—	(177,253)
Other income	32,073	1,208	141	(26,326)	7,096
Equity in earnings of subsidiaries	(43,080)	—	—	43,080	—
Total revenues	(44,851)	(23,335)	14,096	16,754	(37,336)
Costs and expenses:					
Oil and natural gas production	6,772	12,988	2,397	—	22,157
Depreciation, depletion and amortization	3,978	15,242	5,467	—	24,687
Accretion of discount on asset retirement obligations	235	368	14	—	617
General and administrative	79,317	7,487	2,638	—	89,442
Interest	26,673	26,328	—	(26,326)	26,675
Total costs and expenses	116,975	62,413	10,516	(26,326)	163,578
Income (loss) before income taxes	(161,826)	(85,748)	3,580	43,080	(200,914)
Income tax benefit	(21,538)	(42,160)	—	—	(63,698)
Income (loss) before discontinued operations	(140,288)	(43,588)	3,580	43,080	(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
	125,104	—	(3,072)	—	122,032
Net income (loss)	$ (15,184)	$ (43,588)	$ 508	$ 43,080	$ (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	$ 8,463	$53,212	$8,386	$ —	$70,061
Derivative financial instruments	2,856	(3,112)	—	—	(256)
Other income (loss)	7,929	408	112	(6,075)	2,374
Equity earnings of subsidiaries	22,054	—	—	(21,217)	837
Total revenues	41,302	50,508	8,498	(27,292)	73,016
Costs and expenses:					
Oil and natural gas production	1,784	5,908	1,257	—	8,949
Depreciation, depletion and amortization	1,869	9,623	2,579	—	14,071
Accretion of discount on asset retirement obligations	70	147	9	—	226
General and administrative	4,948	381	1,046	—	6,375
Interest	19,413	6,076	—	(6,075)	19,414
Total costs and expenses	28,084	22,135	4,891	(6,075)	49,035
Income (loss) before income taxes	13,218	28,373	3,607	(21,217)	23,981
Income tax expense (benefit)	(3,132)	10,763	—	—	7,631
Net income (loss)	$16,350	$17,610	$3,607	$(21,217)	$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	$ 29,450	$207,761	$118,569	$ —	$355,780
Derivative financial instruments	40,994	132,122	25,548	—	198,664
Other income (loss)	29,862	7,007	2,004	(33,868)	5,005
Equity in earnings of subsidiaries	147,498	—	—	(145,905)	1,593
Total revenues	247,804	346,890	146,121	(179,773)	561,042
Costs and expenses:					
Oil and natural gas production	8,279	32,338	28,257	—	68,874
Depreciation, depletion and amortization	9,393	71,086	55,243	—	135,722
Accretion of discount on asset retirement obligations	252	1,414	348	—	2,014
General and administrative	21,339	11,312	8,555	—	41,206
Interest	52,576	19,716	46,447	(33,868)	84,871
Total costs and expenses	91,839	135,866	138,850	(33,868)	332,687
Income before income taxes	155,965	211,024	7,271	(145,905)	228,355
Income tax expense	17,011	72,390	—	—	89,401
Income from operations	$138,954	$138,634	$ 7,271	$(145,905)	$138,954

EXCO Resources, Inc.

Consolidating statement of cash flow

For the year ended December 31, 2004

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by operating activities	$ 114	$ 62,989	$ 55,425	$—	$ 118,528
Investing Activities:					
Additions to oil and natural gas properties, gathering systems and equipment	(15,547)	(77,100)	(46,874)	—	(139,521)
Proceeds from dispositions of property and equipment	47,364	4,501	—	—	51,865
Acquisition of North Coast Energy, Inc., net of cash acquired	(225,562)	10,429	—	—	(215,133)
Advances/investments with affiliates	(177,607)	6,653	170,954	—	
Proceeds from sale of marketable securities	1,296	—	—	—	1,296
Net cash used in investing activities of discontinued operations	—	—	(79,983)	—	(79,983)
Net cash provided by (used in) investing activities	(370,056)	(55,517)	44,097	—	(381,476)
Financing Activities:					
Proceeds from long-term debt	546,350	—	—	—	546,350
Payments on long-term debt	(158,070)	—	—	—	(158,070)
Principal and interest on notes receivable-employees	256	—	—		256
Deferred financing costs and other	(13,431)	—	—	—	(13,431)
Net cash used in financing activities of discontinued operations	—	—	(91,397)	—	(91,397)
Net cash provided by (used in) financing activities	375,105	—	(91,397)	—	283,708
Net increase in cash	5,163	7,472	8,125	—	20,760
Effect of exchange rates on cash and cash equivalents	—	—	(1,685)		(1,685)
Cash at the beginning of the period	3,372	—	3,961	—	7,333
Cash at end of period, including cash of discontinued operations	$ 8,535	$ 7,472	$ 10,401	$—	$ 26,408

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 provided by (used in) operating activities	$ (76,249)	$ 7,014	$(11,887)	$ —	$ (81,122)
Investing Activities:					
Additions to oil and natural gas properties, gathering systems and equipment	3,987	(112,423)	(42,708)	—	(151,144)
Proceeds from dispositions of oil and natural gas properties	(160)	46,170	—	—	46,010
Proceeds from sale of Addison	444,812	—	(1,415)		443,397
Advances/investments with affiliates	(58,732)	72,282	(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	389,966	6,029	(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	$ (19,063)	$21,021	$ 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	(1,153)	(5,601)	(6,453)	—	(13,207)
Proceeds from dispositions of oil and natural gas properties	(145)	(248)	—	—	(393)
Advances from related parties	20,000	—	—	—	20,000
Other investing activities	263	(234)	234	—	263
Net cash used in investing activities	(1,035)	(6,083)	(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 (used in) operating activities	$ (14,371)	$ 183,679	$ 58,351	$—	$ 227,659
Investing Activities:					
Additions to oil and natural gas properties, gathering systems and equipment	(59,507)	(197,940)	(176,719)	—	(434,166)
Proceeds from dispositions of oil and natural gas properties	140	4,566	1,118	—	5,824
Cash acquired in acquisition of TXOK Acquisition, Inc.	—	32,261	—	—	32,261
Advance to TXOK Acquisition, Inc. for preferred stock redemption	—	(158,750)	—	—	(158,750)
Acquisition of Power Gas Marketing & Transmission, Inc., net of cash acquired	—	(61,776)	—	—	(61,776)
Acquisition of Winchester Energy Company, Ltd., net of cash acquired	—	—	(1,094,910)	—	(1,094,910)
Advances/investments with affiliates	(177,305)	252,867	(75,562)	—	—
Advance payment on Vernon Assets	(80,000)	—	—	—	(80,000)
Net cash used in investing activities	(316,672)	(128,772)	(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)
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 increase (decrease) in cash	(194,530)	3,711	(13,312)	—	(204,131)
Cash at the beginning of the period	191,499	12,075	23,379	—	226,953
Cash at end of period	$ (3,031)	$ 15,786	$ 10,067	$—	$ 22,822

22. 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 Addison, our former Canadian subsidiary):

(in thousands, except per unit amounts)	Amount
2004:	
Proved property acquisition costs	$ 285,811
Unproved property acquisition costs	17,669
Total property acquisition costs(1)	303,480
Development and exploration costs(2)	36,742
Capitalized asset retirement costs	8,462
Depreciation, depletion and amortization per Boe	$ 7.42
Depreciation, depletion and amortization per Mcfe	$ 1.24
For the 275 day period from January 1, 2005 to October 2, 2005:	
Proved property acquisition costs	$ 103,222
Development and exploration costs(2)	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(2)	$ 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(3)	$1,416,834
Unproved property acquisition costs(4)	215,552
Total property acquisition costs	1,632,386
Development and exploration costs(2)	214,283
Capitalized asset retirement costs	21,681
Depreciation, depletion and amortization per Boe	$ 16.44
Depreciation, depletion and amortization per Mcfe	$ 2.74

(1) Includes $199.3 million that was allocated to oil and natural gas properties in the North Coast purchase price allocation.

(2) Exploration costs are not considered material.

(3) 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.

(4) 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, respectively.

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

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

(in thousands)	
Year ended December 31, 2004:	
Sales and transfers of oil and natural gas produced, net of production costs	$(114,116)
Net changes in prices and production costs	84,388
Extensions and discoveries, net of future development and production costs	34,433
Development costs during the period	36,793
Changes in estimated future development costs	11,624
Revisions of previous quantity estimates	(22,714)
Sales of reserves in place	(81,485)
Purchase of reserves in place	320,788
Accretion of discount before income taxes	62,096
Changes in timing, foreign currency translation and other	(48,243)
Net change in income taxes	(35,833)
Net change	$ 247,731
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

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 Addison, our former Canadian subsidiary.

(in thousands, except per unit amounts)	
2004:	
Property acquisition costs	$43,178
Development costs	33,258
Capitalized asset retirement costs	2,388
Depreciation, depletion and amortization per Boe	$ 6.86
Depreciation, depletion and amortization per Mcfe	$ 1.14
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, 2003	6,786	126,392	6,974	208,952
Purchase of reserves in place	1,378	17,105	455	28,103
New discoveries and extensions	656	19,570	1,130	30,286
Revisions of previous estimates	1,068	14,450	1,586	30,374
Production	(549)	(10,345)	(643)	(17,497)
Sales of reserves in place	—	—	—	—
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	—	—	—	—

Estimated Quantities of Proved Developed Reserves

(in thousands)	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Mcfe(1)
December 31, 2004	8,825	155,012	9,250	263,462

(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 Addison'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.

Standardized Measure of Discounted Future Net Cash Flows

(in thousands)	
Year ended December 31, 2004:	
Future cash inflows	$1,525,346
Future production, development and abandonment costs	502,980
Future income taxes	295,697
Future net cash flows	726,669
Discount of future net cash flows at 10% per annum	366,833
Standardized measure of discounted future net cash flows	$ 359,836
Year ended December 31, 2005:	
Future cash inflows	$ —
Future production, development and abandonment costs	—
Future income taxes	—
Future net cash flows	—
Discount of future net cash flows at 10% per annum	—
Standardized measure of discounted future net cash flows	$ —

Near month NYMEX futures prices at December 31, 2004 used in the above table was $43.45 per Bbl or oil and $6.15 per Mmbtu of natural gas, adjusted for historical differentials.

Changes in standardized measure—discontinued operations

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

(in thousands)	
Year ended December 31, 2004:	
Sales and transfers of oil and natural gas produced, net of production costs	$ (74,160)
Net changes in prices and production costs	79,167
Extensions and discoveries, net of future development and production costs	55,950
Development costs during the period	33,258
Changes in estimated future development costs	(20,516)
Revisions of previous quantity estimates	56,311
Sales of reserves in place	—
Purchase of reserves in place	61,904
Accretion of discount before income taxes	30,119
Changes in timing, foreign currency translation and other	(31,253)
Net change in income taxes	(49,963)
Net change	$ 140,817
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

Evaluation of disclosure controls and procedures

We maintain "disclosure controls and procedures," as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act, that are designed to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in Securities and Exchange Commission's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer (CEO), Chief Financial Officer (CFO) and Chief Accounting Officer (CAO), as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating our disclosure controls and procedures, management recognized that disclosure controls and procedures, no matter how well conceived and operated, can provide only reasonable assurance of achieving the desired control objectives and we necessarily are required to apply our judgment in evaluating the cost-benefit relationship of possible disclosure controls and procedures.

Our management evaluated, under the supervision and with the participation of our CEO, CFO and CAO, the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2006 and concluded our controls were effective.

Prior to September 30, 2006, our management had concluded that our disclosure controls and procedures were not effective due to a material weakness relating to accounting for income taxes. We believe we have taken the necessary steps to remediate the material weakness described below. Before concluding that the material weakness was remediated, management implemented and evaluated its new controls and procedures for income tax provisions and determined that these procedures were operating effectively for two consecutive quarters, an amount of time deemed sufficient to conclude that the material weakness no longer existed.

Material weakness in internal control over financial reporting

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

Prior to September 30, 2006, our management had concluded that we did not maintain effective controls over the preparation and review of the quarterly and annual tax provision and the related financial statement presentation and disclosure of income tax matters. Specifically, our controls were not adequate to ensure the completeness and accuracy of the tax provision and the deferred tax balances, including the timing and classification of recording the tax impact of an extraordinary dividend. This control deficiency resulted in the restatement of our consolidated financial statements for the quarters ended June 30, 2005 and September 30, 2005 and audit adjustments to the consolidated financial statements for the years ended December 31, 2004 and 2005, affecting income tax expense and the deferred tax liability accounts. We undertook numerous remedial actions, as described below, to enhance controls.

Remediation of material weakness

During 2005 and 2006, the following remedial activities were undertaken to strengthen internal controls to address the material weakness described above:

- we added additional staff to our tax department, as well as a new tax director.
- we changed the process in calculating our quarterly and annual tax provisions and related deferred taxes that streamline and simplify the process, thereby increasing the effectiveness of our tax calculation process.
- we added staff to our financial reporting function with technical expertise to strengthen our deferred tax calculation and reviews.
- we implemented more stringent reviews of the quarterly tax provision.

We believe the aforementioned steps have resolved the open matters related to the material weakness described above for a period of time sufficient to conclude that our controls are now effective.

Changes in internal control over financial reporting

There have been no changes during the quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The acquisition of Winchester on October 2, 2006 has significantly increased the breadth of our operating and control environment. Our pending acquisitions from Anadarko will significantly increase the number of properties we operate and assets that we manage. Management believes its controls are adequate to effectively integrate the Winchester operations into its existing control environment.

At the end of 2007, Section 404 of the Sarbanes-Oxley Act will require our management to provide an assessment of the effectiveness of our internal control over financial reporting, and our independent registered public accountants will be required to audit management's assessment. We are in the process of performing the system and process documentation, evaluation and testing required for management to make this assessment and for its independent registered public accountants to provide their attestation report. We have not completed this process or its assessment, and this process will require significant amounts of management time and resources. In the course of evaluation and testing, management may identify deficiencies that will need to be addressed and remediated.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

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 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 Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLER 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 Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

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 Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT 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 Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

EXHIBIT NUMBER	Description Of Exhibit
2.1	Merger Agreement, dated July 22, 2006, by and among Winchester Acquisition, LLC, Progress Fuels Corporation, Winchester Energy Company, Ltd., and WGC Holdco, LLC., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated July 22, 2006 and filed on July 25, 2006 and incorporated by reference herein.
2.2	First Amendment to Agreement and Plan of Merger, dated as of September 28, 2006, by and among Winchester Acquisition, LLC, Progress Fuels Corporation, Winchester Energy Company, Ltd., and WGC Holdco, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 2, dated July 22, 2006 and filed on October 4, 2006 and incorporated by reference herein.
3.1	Third Amended and Restated Articles of Incorporation of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 8, 2006 and filed on February 14, 2006 and incorporated by reference herein.
3.2	Amended and Restated Bylaws of EXCO Resources, Inc., filed as an Exhibit to EXCO's current report on Form 8-K, dated February 8, 2006 and filed on February 14, 2006 and incorporated by reference herein.
4.1	Indenture among EXCO Resources, Inc., the Subsidiary Guarantors and Wilmington Trust Company, as Trustee, dated as of January 20, 2004, filed as exhibit (b)(2) to Amendment No. 4 to the Schedule TO filed by NCE Acquisition, Inc. and EXCO Resources, Inc. on January 21, 2004 and incorporated by reference herein.
4.2	First Supplemental Indenture by and among EXCO Resources, Inc., North Coast Energy, Inc., North Coast Energy Eastern, Inc. and Wilmington Trust Company, as Trustee, dated as of January 27, 2004.*
4.3	Second Supplemental Indenture by and among EXCO Resources, Inc., Pinestone Resources, LLC and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2004 filed March 31, 2005 and incorporated by reference herein.
4.4	Third Supplemental Indenture by and among EXCO Resources, Inc., TXOK Acquisition, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K filed on February 21, 2006 and incorporated by reference herein.

EXHIBIT NUMBER	Description Of Exhibit
4.5	Form of 7¼% Global Note Due 2011.**
4.6	Securities Account Control Agreement, dated as of February 10, 2005, among EXCO Resources, Inc., JPMorgan Chase Bank, N.A., Wilmington Trust Company and JPMorgan Securities Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 1, dated January 17, 2005 and filed February 16, 2005 and incorporated by reference herein.
4.7	Securities Account Control Agreement, dated as of February 10, 2005, among EXCO Resources, Inc., Wilmington Trust Company and J.P. Morgan Securities Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K/A Amendment No. 1, dated February 10, 2005 and filed February 16, 2005 and incorporated by reference herein.
4.8	Specimen Stock Certificate for EXCO's common stock, filed as an Exhibit to EXCO's Amendment No. 2 to the Form S-1 (File No. 333- 129935) filed on January 27, 2006 and incorporated by reference herein.
4.9	Fourth Supplemental Indenture, dated as of May 4, 2006, by and among EXCO Resources, Inc., Power Gas Marketing & Transmission, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 4, 2006 and filed on May 10, 2006 and incorporated by reference herein.
4.10	First Amended and Restated Registration Rights Agreement, by and among EXCO Holdings Inc. and the Initial Holders (as defined therein), effective January 5, 2006, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed on January 6, 2006 and incorporated by reference herein.
10.1	Share and Debt Purchase Agreement, dated effective January 12, 2005, among 1143928 Alberta Ltd., EXCO Resources, Inc. and Taurus Acquisition, Inc. filed as an Exhibit to EXCO's Current Report on Form 8-K, dated January 17, 2005 and filed January 21, 2005 and incorporated by reference herein.
10.2	First Amending Agreement to the Share and Debt Purchase Agreement, dated effective February 8, 2005, among 1143928 Alberta Ltd., EXCO Resources, Inc. and Taurus Acquisition, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 1, dated January 17, 2005 and filed February 16, 2005 and incorporated by reference herein.
10.3	Securities Account Control Agreement, dated as of February 10, 2005, among EXCO Resources, Inc., JPMorgan Chase Bank, N.A., Wilmington Trust Company and JPMorgan Securities Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 1, dated January 17, 2005 and filed February 16, 2005 and incorporated by reference herein.

EXHIBIT NUMBER	Description Of Exhibit
10.4	Securities Account Control Agreement, dated as of February 10, 2005, among EXCO Resources, Inc., Wilmington Trust Company and J.P. Morgan Securities Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 1, dated January 17, 2005 and filed February 16, 2005 and incorporated by reference herein.
10.5	Indenture among EXCO Resources, Inc., the Subsidiary Guarantors and Wilmington Trust Company, as Trustee, dated as of January 20, 2004, filed as exhibit (b)(2) to Amendment No. 4 to the Schedule TO filed by NCE Acquisition, Inc. and EXCO Resources, Inc. on January 21, 2004 and incorporated by reference herein.
10.6	First Supplemental Indenture by and among EXCO Resources, Inc., North Coast Energy, Inc., North Coast Energy Eastern, Inc. and Wilmington Trust Company, as Trustee, dated as of January 27, 2004.*
10.7	Second Supplemental Indenture by and among EXCO Resources, Inc., Pinestone Resources, LLC and Wilmington Trust Company, as Trustee, dated as of December 21, 2004, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2004 filed March 31, 2005 and incorporated by reference herein.
10.8	Third Supplemental Indenture by and among EXCO Resources, Inc., TXOK Acquisition, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 1, dated February 8, 2006 and filed on February 21, 2006 and incorporated by reference herein.
10.9	Fourth Supplemental Indenture, dated as of May 4, 2006, by and among EXCO Resources, Inc., Power Gas Marketing & Transmission, Inc. and Wilmington Trust Company, as Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 4, 2006 and filed on May 10, 2006 and incorporated by reference herein.
10.10	Form of 7¼% Global Note Due 2011.**
10.11	EXCO Holdings Inc. 2005 Long-term Incentive Plan, dated October 5, 2005 filed as an Exhibit to EXCO's Current Report on Form 8-K, dated September 30, 2005 and filed on October 7, 2005 and incorporated by reference herein.***
10.12	Form of Incentive Stock Option Agreement of the EXCO Holdings Inc. 2005 Long-term Incentive Plan filed as an Exhibit to EXCO's Current Report on Form 8-K, dated September 30, 2005 and filed on October 7, 2005 and incorporated by reference herein.***
10.13	Form of Nonqualified Stock Option Agreement of the EXCO Holdings Inc. 2005 Long-term Incentive Plan filed as an Exhibit to EXCO's Current Report on Form 8-K, dated September 30, 2005 and filed on October 7, 2005 and incorporated by reference herein.***
10.14	Form of Restricted Stock Award Agreement of the EXCO Holdings Inc. 2005 Long-term Incentive Plan filed as an Exhibit to EXCO's Current Report on Form 8-K, dated September 30, 2005 and filed on October 7, 2005 and incorporated by reference herein.***

EXHIBIT NUMBER	Description Of Exhibit
10.15	Letter Agreement, dated October 3, 2005, between EXCO Resources, Inc. and JPMorgan Chase Bank, N.A., as agent for certain lenders under the Credit Agreement by and among EXCO Holdings II, Inc. (EXCO Holdings Inc. as successor by merger) as Borrower and JPMorgan Chase Bank, N.A., as Administrative Agent for itself and the Lenders defined therein, dated October 3, 2005, as filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter ended September 30, 2005 filed November 14, 2005 and incorporated by reference herein.
10.16	Promissory Note in the maximum amount of $10,000,000, dated October 7, 2005, made by EXCO Holdings Inc., payable to EXCO Resources, Inc., filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter ended September 30, 2005 filed November 14, 2005 and incorporated by reference herein.
10.17	First Amended and Restated Registration Rights Agreement, by and among EXCO Holdings Inc. and the Initial Holders (as defined therein), effective January 5, 2006, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed on January 6, 2006 and incorporated by reference herein.
10.18	Agreement and Plan of Merger between EXCO Holdings Inc. and EXCO Resources, Inc., dated February 9, 2006, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 8, 2006 and filed February 14, 2006 and incorporated by reference herein.
10.19	Credit Agreement for Senior Secured Revolving Credit Facility, dated as of September 27, 2005, by and among TXOK Acquisition, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the Lenders (as defined therein), JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Securities Inc., as Sole Bookrunner and Lead Arranger, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 1, dated February 8, 2006 and filed on February 21, 2006 and incorporated by reference herein.
10.20	First Amendment to Revolving Credit Agreement, dated as of December 15, 2005, by and among TXOK Acquisition, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the Lenders (as defined herein), and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 1, dated February 8, 2006 and filed on February 21, 2006 and incorporated by reference herein.
10.21	Second Amendment to Revolving Credit Agreement, dated as of February 6, 2006, by and among TXOK Acquisition, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the Lenders (as defined therein), and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 1, dated February 8, 2006 and filed on February 21, 2006 and incorporated by reference herein.

EXHIBIT NUMBER	Description Of Exhibit
10.22	Subsidiary Guaranty, dated February 14, 2006, among TXOK Acquisition, Inc., TXOK Energy Resources Company, TXOK Energy Holdings, L.L.C., TXOK Texas Energy Holdings, LLC and TXOK Texas Energy Resources, L.P., as Subsidiary Guarantors, in favor of JPMorgan Chase Bank, NA, as agent for itself and the Lenders defined therein, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 1, dated February 8, 2006 and filed on February 21, 2006 and incorporated by reference herein.
10.23	Amended and Restated Credit Agreement, dated as of March 17, 2006, among EXCO Resource, Inc. as Borrower, certain of its subsidiaries, as Guarantors, the Lenders defined therein, JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Securities Inc., as Sole Bookrunner and Lead Manager, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 17, 2006 and filed on March 23, 2006 and incorporated by reference herein.
10.24	EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Registration Statement on Form S-8 (File No. 333-132551) filed on March 17, 2006 and incorporated by reference herein.***
10.25	Form of Incentive Stock Option Agreement for the EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed herewith.***
10.26	Form of Nonqualified Stock Option Agreement for the EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed herewith.***
10.27	Form of Restricted Stock Award Agreement for the EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Registration Statement on Form S-8 (File No. 333-132551) filed on March 17, 2006 and incorporated by reference herein.***
10.28	Merger Agreement, dated July 22, 2006, by and among Winchester Acquisition, LLC, Progress Fuels Corporation, Winchester Energy Company, Ltd., and WGC Holdco, LLC., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated July 22, 2006 and filed on July 25, 2006 and incorporated by reference herein.
10.29	First Amendment to Agreement and Plan of Merger, dated as of September 28, 2006, by and among Winchester Acquisition, LLC, Progress Fuels Corporation, Winchester Energy Company, Ltd., and WGC Holdco, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 2, dated July 22, 2006 and filed on October 4, 2006 and incorporated by reference herein.
10.30	Payment Performance Guaranty, dated July 22, 2006, by and between Progress Fuels Corporation and EXCO Resources, Inc., filed as an exhibit to EXCO's Current Report on Form 8-K, dated July 22, 2006 and filed on July 24, 2006 and incorporated by reference herein.

EXHIBIT NUMBER	Description Of Exhibit
10.31	Senior Revolving Credit Agreement, dated October 2, 2006, among EXCO Partners Operating Partnership, LP, certain of its subsidiaries, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 2, dated July 22, 2006 and filed on October 4, 2006 and incorporated by reference herein.
10.32	Senior Term Credit Agreement, dated October 2, 2006, among EXCO Partners Operating Partnership, LP, certain of its subsidiaries, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 2, dated July 22, 2006 and filed on October 4, 2006 and incorporated by reference herein.
10.33	First Amendment to Credit Agreement, dated October 2, 2006, among EXCO Resources, Inc., certain of its subsidiaries, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 2, dated July 22, 2006 and filed on October 4, 2006 and incorporated by reference herein.
10.34	Amended and Restated Equity Contribution Agreement, dated October 4, 2006, among EXCO Resources, Inc., EXCO Partners Operating Partnership, LP, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 2, dated July 22, 2006 and filed on October 4, 2006 and incorporated by reference herein.
10.35	Senior Term Credit Agreement, dated October 2, 2006, as amended and restated as of October 13, 2006, among EXCO Partners Operating Partnership, LP, certain of its subsidiaries, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 3, dated July 22, 2006 and filed on October 19, 2006 and incorporated by reference herein.
10.36	Second Amended and Restated Equity Contribution Agreement, dated October 13, 2006, among EXCO Resources, Inc., EXCO Partners Operating Partnership, LP, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K/A-Amendment No. 3, dated July 22, 2006 and filed on October 19, 2006 and incorporated by reference herein.
10.37	Second Amended and Restated EXCO Resources, Inc. Severance Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 8, 2006 and filed on November 9, 2006 and incorporated by reference herein.
10.38	Amended and Restated 2007 Director Plan of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated January 15, 2007 and filed on January 16, 2007 and incorporated by reference herein.

EXHIBIT NUMBER	Description Of Exhibit
10.39	Purchase and Sale Agreement by and among Anadarko Petroleum Corporation and Anadarko Gathering Company, as Seller, and Vernon Holdings, LLC, as Purchaser, dated December 22, 2006, filed as an Exhibit to EXCO's Pre-Effective Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-139568) filed on January 16, 2007 and incorporated by reference herein.
10.40	Guaranty dated December 22, 2006 by EXCO Resources, Inc. in favor of Anadarko Petroleum Corporation and Anadarko Gathering Company, filed as an Exhibit to EXCO's Pre-Effective Amendment No. 1 to the Registration Statement on Form S-1 (File No. 333-139568) filed on January 16, 2007 and incorporated by reference herein.
10.41	Purchase and Sale Agreement by and among EXCO Resources, Inc., Anadarko Petroleum Corporation, Anadarko E&P Company, LP, Howell Petroleum Corporation, and Kerr-McGee Oil & Gas Onshore LP, dated February 1, 2007, filed herewith.
10.42	First Amendment to Senior Revolving Credit Agreement effective as of December 31, 2006 among EXCO Partners Operating Partnership, LP, certain of its subsidiaries, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as an exhibit to EXCO's Current Report on Form 8-K, dated March 8, 2007 and filed march 13, 2007 and incorporated by reference herein.
14.1	Code of Ethics for the Chief Executive Officer and Senior Financial Officers, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed January 6, 2006 and incorporated by reference herein.
14.2	Code of Business Conduct and Ethics for Directors, Officers and Employees, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed January 6, 2006 and incorporated by reference herein.
14.3	Amendment No. 1 to EXCO Resources, Inc. Code of Business Conduct and Ethics for Directors, Officers and Employees, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 8, 2006 and filed on November 9, 2006 and incorporated by reference herein.
21.1	Subsidiaries of the registrant, filed herewith.
23.1	Consent of KPMG LLP, filed herewith.
23.2	Consent of PricewaterhouseCoopers LLP, filed herewith.
23.3	Consent of Lee Keeling and Associates, Inc., filed herewith.
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Executive Officer of EXCO Resources, Inc., filed herewith.
31.2	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Financial Officer of EXCO Resources, Inc., filed herewith.

EXHIBIT NUMBER	Description Of Exhibit
31.3	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Accounting Officer of EXCO Resources, Inc., filed herewith.
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer of EXCO Resources, Inc., filed herewith.
99.1	Audit Committee Charter, filed as an Exhibit to EXCO's Form 8-K filed November 24, 2004 and *incorporated by reference herein.*

* Filed as an Exhibit to EXCO's Form S-4 filed March 25, 2004 and incorporated by reference herein.

** Filed as an Exhibit to EXCO's Pre-effective Amendment No. 1 to the Form S-4 filed April 20, 2004 and incorporated by reference herein.

*** These exhibits are management contracts.

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.

EXCO RESOURCES, INC.
(Registrant)

Date: March 19, 2007

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: March 19, 2007

/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/ EARL E. ELLIS
Earl E. Ellis
Director

/s/ ROBERT H. NIEHAUS
Robert H. Niehaus
Director

/s/ BOONE PICKENS
Boone Pickens
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.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A
Amendment No. 1

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

For the Fiscal Year Ended December 31, 2006

OR

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

For the Transition Period from to

Commission File Number 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 of this Form 10-K. ☐

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

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒

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

As of April 3, 2007, the registrant had 104,241,415 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 $809,940,000.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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EXPLANATORY NOTE

EXCO Resources, Inc. is filing this Amendment No. 1 on Form 10-K/A (this "Amendment") to its Annual Report on Form 10-K for the fiscal year ended December 31, 2006, originally filed on March 19, 2007, for the purpose of including the information required by Part III of Form 10-K. In addition, we are also including as exhibits to this Amendment the certifications required under Section 302 of the Sarbanes-Oxley Act of 2002. Because no financial statements are contained within this Amendment, we are not including certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. Except as set forth herein, no other changes are made to our Annual Report on Form 10-K for the fiscal year ended December 31, 2006.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Common Stock Directors

The following table and text set forth the name, age and positions of each of our directors elected by our common stockholders:

Name	Age	Position
Douglas H. Miller	59	Chairman and Chief Executive Officer
Stephen F. Smith	65	Vice Chairman and President
Jeffrey D. Benjamin(1)(2)(3)	45	Director
Earl E. Ellis(1)(2)(3)	65	Director
Robert H. Niehaus(1)(2)(3)	51	Director
Boone Pickens	78	Director
Robert L. Stillwell(2)(3)	70	Director

(1) Member of the audit committee.

(2) Member of the compensation committee.

(3) Member of the nominating and corporate governance committee.

Douglas H. Miller became the Chairman of our Board of Directors and our Chief Executive Officer in December 1997. Mr. Miller was Chairman of the Board of Directors and Chief Executive Officer of Coda Energy, Inc., or Coda, an independent oil and natural gas company, from October 1989 until November 1997 and served as a director of Coda from 1987 until November 1997.

Stephen F. Smith joined us in June 2004 as Vice Chairman of our Board of Directors and was appointed President and Secretary in October 2005. He served as our Secretary until April 2006. Prior to joining us, Mr. Smith was co-founder and Executive Vice President of Sandefer Oil and Gas, Inc., an independent oil and gas exploration and production company, from January 1980 to June 2004. Mr. Smith was one of our directors from March 1998 to July 2003. Prior to 1980, Mr. Smith was an Audit Partner with Arthur Andersen LLP.

Jeffrey D. Benjamin became one of our directors in October 2005 and was previously one of our directors from August 1998 through July 2003 and a director of our parent holding company from July 2003 through its merger into us. Mr. Benjamin has been a Senior Advisor to Apollo Management, LP since September 2002. He had previously been a Managing Director of Libra Securities LLC, an investment banking firm, from January 2002 to September 2002 and served as Co-Chief Executive Officer of Libra Securities from January 1999 to December 2001. Mr. Benjamin is also a director of Dade Behring Holdings Inc., NTL Incorporated and Goodman Global, Inc.

Earl E. Ellis became one of our directors in October 2005 and was previously one of our directors from March 1998 through July 2003. Mr. Ellis has served as chairman and chief executive officer of Carolina Soy Products, a soy based product manufacturing company since September 2003. Mr. Ellis has also been a private investor since 2001. He served as a Director of Coda from 1992 until 1996. Mr. Ellis served as a managing partner of Benjamin Jacobson & Sons, LLC, specialists on the New York Stock Exchange. He had been associated with Benjamin Jacobson & Sons, LLC from 1977 to 2001.

Robert H. Niehaus became one of our directors in November 2004 and was a director of our parent holding company from July 2003 through its merger into us. Mr. Niehaus is the Chairman and Managing Partner of Greenhill Capital Partners, LLC, a private equity investment firm, and a Managing Director of Greenhill & Co., LLC. Prior to joining Greenhill in January 2000 to start its private equity business, Mr. Niehaus was a Managing Director in Morgan Stanley's private equity investment department from 1990 to 1999. Mr. Niehaus is a director of the American Italian Pasta Company, Global Signal Inc., Heartland Payment Systems, Inc. and several private companies.

Boone Pickens became one of our directors in October 2005 and was previously one of our directors from March 1998 through July 2003. Mr. Pickens has served as the Chairman and CEO of BP Capital LP since September 1996 and Mesa Water, Inc. since August 2000 and is a board member of Clean Energy. BP Capital LP or affiliates is the general partner and an investment advisor of private funds investing in energy commodities (BP Capital Energy Fund) and publicly-traded energy equities (BP Capital Equity Fund and its offshore counterpart). Clean Energy is the largest provider of natural gas (CNG and LNG) and related services in North America. He was the founder of Mesa Petroleum Co., an independent oil and natural gas exploration and production company. He served as CEO and Chairman of the Board of Mesa from its inception until his departure in 1996. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—TXOK acquisition" for a description of certain related party transactions involving Mr. Pickens.

Robert L. Stillwell became one of our directors in October 2005. Mr. Stillwell has served as the General Counsel of BP Capital LP, Mesa Water, Inc. and affiliated companies engaged in the petroleum business since 2001. Mr. Stillwell was a lawyer and Senior Partner at Baker Botts LLP in Houston, Texas from 1969 to 2001. He also served as a director of Mesa Petroleum Co. and Pioneer Natural Resources Company from 1969 to 2001.

Preferred Stock Directors

The following table and text set forth the name, age and positions of each of our directors appointed in accordance with the terms of our 7.0% Cumulative Convertible Perpetual Preferred Stock, or our Convertible Preferred Stock:

Name	Age	Position
Vincent J. Cebula	43	Director
Jeffrey S. Serota...............	41	Director

Vincent J. Cebula became one of our directors on March 30, 2007. Mr. Cebula previously served as a director of EXCO Resources and EXCO Holdings from July 2003 until October 2005. For the past five years, Mr. Cebula has been a Managing Director of Oaktree Capital Management, LLC. Mr. Cebula is a director of Cherokee International Corporation, a designer and manufacturer of custom and standard power supplies, and privately-held Pegasus Aviation Finance Company.

Jeffrey S. Serota became one of our directors on March 30, 2007. Mr. Serota previously served as a director of EXCO Resources and EXCO Holdings from July 2003 until October 2005. For the past five years, Mr. Serota has been a Managing Director of Ares Management, LLC and its related entities.

Mr. Cebula was designated by Oaktree Capital Management, LLC, or Oaktree, which beneficially owns 8.5% of our common stock (including shares issuable upon conversion of our Series B Convertible Preferred Stock), all 11,700 shares of our outstanding Series B Convertible Preferred Stock and 48,300 shares of our Series A-1 Hybrid Preferred Stock. Pursuant to the Statement of Designation of the Series B Convertible Preferred Stock, the holders of a majority of Series B Convertible Preferred Stock have the right to elect one director to serve on our Board of Directors for so long as Oaktree beneficially owns an aggregate of at least 10,000 shares of our Series B Convertible Preferred Stock, Series A-1 Hybrid Preferred Stock and/or Series A-2 Hybrid Preferred Stock. We have also entered into a letter agreement 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

Convertible Preferred Stock and (ii) less than 25% of the shares of Convertible Preferred Stock and Hybrid Preferred Stock originally issued on March 30, 2007 remain outstanding, 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).

Mr. Serota was designated by Ares Management LLC, or Ares, which owns 7.6% of our common stock (including shares issuable upon conversion of our Series C Convertible Preferred Stock), all 2,925 shares of our outstanding Series C Convertible Preferred Stock and 12,075 shares of our Series A-1 Hybrid Preferred Stock. Pursuant to the Statement of Designation of the Series C Convertible Preferred Stock, the holders of a majority of the Series C Convertible Preferred Stock have the right to elect one director to serve on our Board of Directors for so long as Ares beneficially owns an aggregate of at least 10,000 shares of our Series C Convertible Preferred Stock, Series A-1 Hybrid Preferred Stock and/or Series A-2 Hybrid Preferred Stock. We have also entered into a letter agreement 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 Convertible Preferred Stock and (ii) less than 25% of the shares of Convertible 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).

Pursuant to the Statement of Designation of the Series A-1 Convertible Preferred Stock, for so long as there is outstanding a number of shares of Convertible Preferred Stock and Hybrid Preferred Stock that is equal to 25% or more of such shares currently outstanding, collectively referred to herein as the initial preferred shares, the holders of at least 60% of the then-outstanding shares of the Series A-1, Series B and Series C Convertible Preferred Stock have the right to elect four directors to serve on our Board of Directors; provided that the right to elect those four directors is to be reduced by the number of directors that may then be elected by the Series B and Series C Convertible Preferred Stock. If less than 25% but 10% or more of the initial preferred shares are outstanding, the number of directors that may be elected by the Series A-1, Series B and Series C Convertible Preferred Stock will decrease to two, which number is to be further reduced by the number of directors that may then be elected by the Series B and Series C Convertible Preferred Stock. If less than 10% of the initial preferred shares are outstanding, the holders of Series A-1 Convertible Preferred Stock will not have the right to elect any preferred directors. Accordingly, the holders of at least 60% of the outstanding shares of the Series A-1, Series B and Series C Convertible Preferred Stock currently have the right to elect two additional preferred stock directors. These holders have not yet exercised their right to elect the two additional preferred stock directors, but plan to do so in conjunction with the next annual meeting of our holders of common stock.

There are no family relationships between any of our directors or executive officers.

Executive Officers

The following table sets forth certain information with respect to our executive officers, other than Messrs. Douglas H. Miller and Stephen F. Smith, whose information is set forth above under the caption "—Common Stock Directors."

Name	Age	Position
J. Douglas Ramsey, Ph.D. . . .	46	Vice President, Chief Financial Officer and Treasurer
Harold L. Hickey	51	Vice President and Chief Operating Officer
William L. Boeing	52	Vice President, General Counsel and Secretary
Mark E. Wilson	47	Vice President, Chief Accounting Officer and Controller

J. Douglas Ramsey, Ph.D., became our Chief Financial Officer and a Vice President in December 1997. Dr. Ramsey was one of our directors from March 1998 until October 5, 2005. From March 1992 to December 1997, Dr. Ramsey worked for Coda Energy, Inc. as Financial Analyst and Assistant to the President and then as Financial Planning Manager. Dr. Ramsey also taught finance at Southern Methodist University in their undergraduate and professional MBA programs.

Harold L. Hickey became our Vice President and Chief Operating Officer in October 2005. Prior to then and beginning in January 2004, Mr. Hickey served as President of our wholly-owned subsidiary, North Coast Energy, Inc. Mr. Hickey was our Production and Asset Manager from February 2001 to January 2004. From April 2000 until he joined us, Mr. Hickey was Chief Operating Officer of Inca Natural Resources Group, L.P., an independent oil and natural gas exploration company. Prior to that, Mr. Hickey worked at Mobil Oil Corporation from 1979 to March 2000.

William L. Boeing became our Vice President, General Counsel and Secretary in April 2006. From October 1980 to March 2006, Mr. Boeing was initially an associate and later a partner at our outside law firm, Haynes and Boone, LLP, in Dallas, Texas.

Mark E. Wilson became our Controller and one of our Vice Presidents in August 2005. Mr. Wilson then became our Chief Accounting Officer in November 2006. He began his career in 1980 with Diamond Shamrock Corporation. Since that time, he has served in Controller roles with Maxus Energy Corporation, Snyder Oil Corporation and Repsol-YPF International. From 1993 to 1997, Mr. Wilson held managerial positions with Coopers & Lybrands' Utility Industry Consulting practice. From September 2000 until August 2005, Mr. Wilson served as Vice President and Controller and Chief Financial Officer of Epoch Holding Corporation, a publicly traded investment management and advisory firm and registered investment adviser.

Other Officers of Our Company

Michael R. Chambers Sr., age 51, became our Vice President of Operations in February 2007. Prior to joining EXCO Resources, Mr. Chambers was the Operations General Manager for Anadarko's Eastern Region Operations from August 2006 to February 2007 and Rockies Production Manager from August 2000 to August 2006. Mr. Chambers joined Anadarko in January 2000. Mr. Chambers worked at Mobil Oil Corporation from 1979 to January 2000.

Charles R. Evans, age 53, joined us in February 1998, became one of our Vice Presidents in March 1998 and was our Chief Operating Officer from December 2000 until October 2005. He currently serves as one of our Vice Presidents. After working for Sun Oil Co., he joined TXO Production Corp. in 1979 and was appointed Vice President of Engineering and Evaluation in 1989. In 1990, he was named Vice President of Engineering and Project Development for Delhi Gas Pipeline Corporation, a natural gas gathering, processing and marketing company. Mr. Evans served as Director-Environmental Affairs and Safety for Delhi until December 1997.

Richard L. Hodges, age 55, became one of our Vice Presidents in October 2000. He began his career with Texaco, Inc. and has served in various land management capacities with several independent oil and gas companies during the past 27 years. He served as Vice President of Land for Central Resources, Inc. until we acquired the Central properties in September 2000.

John D. Jacobi, age 53, became one of our Vice Presidents in February 1999. In 1991, he co-founded Jacobi-Johnson Energy, Inc., an independent oil and natural gas producer, and served as its President until January 1997. He served as the Vice President and Treasurer of Jacobi-Johnson from January 1997 until May 8, 1998, when the company was sold to us.

Daniel A. Johnson, age 55, became one of our Vice Presidents in February 1999. In 1991, he co-founded Jacobi-Johnson Energy, Inc., an independent oil and natural gas producer. He served as its President from January 1997 until the company was sold to us on May 8, 1998.

Steve Puckett, age 48, became our Vice President of Reservoir Engineering in December 2006. Mr. Puckett was our Manager of Engineering and Operations from April 2000 until December 2006. From January 1998 until April 2000 he served as a petroleum engineering consultant for Petra Resources, Inc. From March 1993 until January 1998 he worked for Enserch Exploration, Inc. as a reservoir engineer. From May 1981 until January 1993 he was employed by Oryx Energy Company as an operations engineer and reservoir engineer. He is a registered professional engineer in Texas and a member of the Society of Petroleum Engineers.

Paul B. Rudnicki, age 29, became our Vice President of Financial Planning and Analysis in August 2006. Prior to that and beginning in July 2003, Mr. Rudnick served as Financial Planning Manager. Mr. Rudnicki was a Financial Analyst and Assistant to the CFO from June 2000 to July 2003.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our officers and directors, and persons who own more than 10% of a registered class of our equity securities, to file reports of ownership and changes of ownership with the Securities and Exchange Commission, or SEC. Our officers, directors and 10% shareholders are required by SEC regulation to furnish us with copies of all Section 16(a) forms so filed. Based solely on review of copies of such forms received, we believe that, during the last fiscal year, all filing requirements under Section 16(a) applicable to our officers, directors and 10% shareholders were timely met, except for the following: one Form 4 filed by each of Messrs. Miller, Smith, Ramsey and Hickey, related to the purchase of our common stock through our 401(k) plan.

Codes of Business Conduct and Ethics

We have adopted Corporate Governance Guidelines, a Code of Business Conduct and Ethics, and a Code of Ethics for the Chief Executive Officer and Senior Financial Officers. Copies of the codes can be obtained free of charge from our web site, www.excoresources.com, or by contacting us at the address appearing on the first page of this Amendment to the attention of Secretary or by telephone at (214) 368-2084. We intend to post any amendments to, or waivers from, our Code of Ethics that apply to our chief executive officer or senior financial officers on our web site at www.excoresources.com.

Shareholders Nominations for Director Nominees

No material changes have been made to the procedures by which our shareholders may recommend nominees to our board of directors since we described the procedures in our Annual Report on Form 10-K for the fiscal year ended December 31, 2005. Our nominating and corporate governance committee will propose the slate of directors to be put up for election at our annual shareholders meeting. See "—Preferred Stock Directors" for a discussion of how our preferred stock directors are appointed.

Audit Committee

We currently maintain an audit committee. The audit committee recommends the appointment of our independent registered public accountants, reviews our internal accounting procedures and financial statements and consults with and reviews the services provided by our independent registered public accountants, including the results and scope of their audit. The audit committee is currently comprised of Messrs. Benjamin (chair), Ellis and Niehaus, each of whom are independent, within the meaning of applicable SEC and New York Stock Exchange, or NYSE, rules. Mr. Benjamin has been designated as an audit committee financial expert, as currently defined under the SEC rules implementing the Sarbanes-Oxley Act of 2002. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—Director Independence." We believe that the composition and functioning of our audit committee complies with all applicable requirements of the Sarbanes-Oxley Act of 2002, as well as NYSE and SEC rules and regulations.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

Overview of Compensation Program

The compensation committee of our Board of Directors has responsibility for establishing, implementing and continually monitoring adherence with our compensation philosophy. The compensation committee reviews and recommends to our Board of Directors the compensation and benefits for our executive officers, administers our stock plans and assists with the establishment of general policies relating to compensation and benefits for all of our employees. The compensation committee ensures that the total compensation paid to our officers is fair, reasonable and competitive. Generally, the types of compensation and benefits provided to our executive officers are similar to those provided to our other officers and employees. We do not have compensation plans that are solely for executive officers.

Throughout this report, the individuals who served as our chief executive officer and chief financial officer during fiscal 2006, as well as the other individuals included in the Summary Compensation Table, are referred to as "Named Executive Officers."

Compensation Philosophy and Objectives

We believe that the most effective compensation program is one that is designed to reward all employees, not just executives, for the achievement of our short-term and long-term strategic goals. As a result, our compensation philosophy is to provide all employees with both cash and stock-based incentives that foster the continued growth and overall success of our Company and encourage employees to maximize shareholder value. Under this philosophy, all of our employees, from the most senior executives of our organization to entry level, have aligned interests.

When establishing total compensation for Named Executive Officers, our compensation committee has the following objectives:

- to attract, retain and motivate highly qualified and experienced individuals;
- to ensure that a significant portion of their total compensation is "at risk" in the form of equity compensation; and
- to offer competitive compensation packages that are consistent with our core values.

Role of Executive Officers in Compensation Decisions

Prior to our initial public offering, or IPO, in February of 2006, our Board of Directors, with input from our chief executive officer, president and chief financial officer, approved the compensation packages for our executive officers. After the IPO, our Board of Directors delegated authority to the compensation committee to make all compensation decisions for our executive officers and approve all grants of equity awards to our executive officers.

The compensation committee annually reviews the performance of our chief executive officer and our president. Our chief executive officer and our president annually review the performance of each other executive officer. The conclusions reached and recommendations based on these reviews, including with respect to salary adjustments and annual bonus award amounts, are presented to the compensation committee. The compensation committee can exercise its discretion in modifying any recommended adjustments or awards to our executives.

Setting Executive Compensation

Based on the foregoing objectives, the compensation committee structured our annual and long-term incentive-based cash and non-cash executive compensation to motivate executives to achieve our business goals and reward the executives for achieving those goals. In September 2006, we engaged an outside consulting firm to conduct an annual review of our total compensation program for our Named Executive Officers as well as for other key executives. This consulting firm provided the compensation committee with relevant market data and alternatives to consider when making compensation decisions for our executive officers.

In making compensation decisions, the compensation committee compares each element of total compensation against a peer group of publicly-traded oil and natural gas companies with similar operations and revenue. The peer group consists of companies against which the compensation committee believes we compete for talent and for shareholder investment.

We compete with many larger companies for top executive-level talent. As a result, the compensation committee generally sets cash compensation for executive officers at or near the median percentile of compensation paid to similarly situated executives of the companies comprising the peer group. Variations to this objective may occur as dictated by the experience level of the individual and market factors. These objectives recognize the compensation committee's expectation that, over the long term, we will continue to generate shareholder returns in excess of the average of our peer group.

A significant percentage of total compensation is allocated to equity incentives as a result of the philosophy mentioned above. There is no pre-established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation for our executive officers. Rather, the compensation committee relies on each committee member's knowledge and experience as well as information provided by management and an outside consulting firm to determine the appropriate level and mix of compensation. Income from equity incentive compensation is realized only as a result of the successful performance of our company over time.

Executive Compensation Components

For the fiscal year ended December 31, 2006, the principal components of compensation for Named Executive Officers were:

- base salary;
- cash bonus;
- long-term incentive compensation;
- retirement and other benefits; and
- perquisites and other personal benefits.

Base Salary

We provide Named Executive Officers with a base salary to compensate them for services rendered during the fiscal year. Base salary ranges for Named Executive Officers are determined for each executive based on position and responsibility by using market and other data. Base salary ranges are designed so that salary opportunities for a given position will be at or above the 50% percentile of the base salary of our peer group.

During its review of base salaries for executives, the compensation committee primarily considers:

- market data provided by our outside consultants;
- internal review of the executive's compensation, both individually and relative to other officers; and
- individual performance of the executive.

Executive salary levels are typically considered annually. Merit based increases to salaries of executive officers are based on the compensation committee's assessment of each individual's performance.

In accordance with the philosophy, objectives and procedures set forth in this Compensation Discussion and Analysis, our compensation committee reviewed the annual base salaries for our Named Executive Officers and established the following 2007 base salaries effective April 1, 2007 for our Named Executive Officers:

- Douglas H. Miller—$800,000
- Stephen F. Smith—$600,000
- William L. Boeing—$400,000
- J. Douglas Ramsey, Ph.D.—$350,000
- Harold L. Hickey—$350,000

Cash Bonus

Although we do not have a formal cash bonus plan, we have historically paid year-end cash bonuses in the range of 10% to 20% of each employee's annual base salary. Consistent with our compensation philosophy, all employees, from the most senior executives of our organization to entry level, have historically received the same percentage level bonuses, pro-rated for any partial period of service, as those received by our Named Executive Officers. Exceptions are made from time to time, including in 2006, to provide additional cash bonuses to certain employees who are not Named Executive Officers and who make extraordinary contributions to our success. In 2006, we paid cash bonuses to each employee and each Named Executive Officer in an amount equal to 20% of their respective annual base salary, subject to some merit based exceptions for certain employees that are not Named Executive Officers. The payment of any cash bonus to Named Executive Officers must be approved by our compensation committee, whose determination is based on the overall success of our company. Each of the Named Executive Officers received the following cash bonus payments in December 2006 for fiscal 2006 performance.

Name	2006 Cash Bonus
Douglas H. Miller	$120,000
Stephen F. Smith	$ 80,000
J. Douglas Ramsey, Ph.D.	$ 60,000
Harold L. Hickey	$ 60,000
William L. Boeing	$ 52,500

Long-Term Incentive Compensation

2005 Long-Term Incentive Plan. In many cases, incentives granted under the EXCO Resources, Inc. 2005 Long-Term Incentive Plan comprise the largest portion of our Named Executive Officers' total compensation package. This incentive plan was originally adopted by the Holdings II Board of Directors and approved by Holdings II stockholders in September 2005 and ultimately assumed by us in connection with our initial public offering. A total of 10,000,000 shares of our common stock have been authorized for issuance under the incentive plan. The stated purpose of this plan is to provide financial incentives to selected employees and to promote our long-term growth and financial success by:

- attracting and retaining employees of outstanding ability;
- strengthening our capability to develop, maintain and direct a competent management team;
- providing an effective means for selected employees to acquire an ownership interest in us;
- motivating key employees to achieve long-range performance goals and objectives; and
- providing incentive compensation competitive with other similar companies.

Our compensation committee administers the incentive plan and the awards granted under the incentive plan. Awards under the incentive plan can consist of incentive stock options, non-qualified stock options, restricted stock, stock appreciation rights and other awards. However, in accordance with our compensation philosophy, we have historically only used stock options as incentives for our employees. An important objective of our long-term incentive compensation is to strengthen the relationship between the long-term value of our stock price and the potential financial gain for employees. Stock options provide all employees with the opportunity to purchase our common stock at a price fixed on the grant date regardless of the future market price.

Pursuant to the terms of the stock option agreements that we entered into with our option holders, the stock options granted:

- are vested as to 25% of the shares subject to the option on the date of grant and will vest an additional 25% on each of the next three anniversaries of the date of grant;
- expire on the tenth anniversary of the date of grant, or sooner under some circumstances; and
- become fully vested and exercisable, subject to their early termination as provided in the option agreements, immediately prior to a change of control of us.

A stock option becomes valuable only if our common stock price increases above the option exercise price and the holder of the option remains employed during the period required for the option to "vest," thus providing an incentive for an option holder to remain our employee. In addition, stock options link a portion of an employee's compensation to shareholders' interests by providing an incentive to increase the market price of our stock.

Currently, all new employees are awarded stock options on the first business day of the month following an employee's hire date and after that only when stock option bonuses are paid, if approved by our compensation committee. Historically, we have awarded stock option bonuses to our employees in December. Consistent with our compensation philosophy, these stock option bonuses are granted at the same ratable percentage for all employees, including Named Executive Officers, based on each employee's annual base salary. In December 2006, we granted stock option bonuses to our employees, including Named Executive Officers, such that each employee received an option for that number of shares equal to 10% of such employee's annual base salary earned during the year, pro rata for any partial year of service. Options are awarded at the NYSE's closing price of our common stock on the date of the grant. The compensation committee has never granted options with an exercise price that is less than the closing price of our common stock on the grant date, nor has it granted options which are priced on a date other than the grant date.

The exercise prices of the stock options granted to our Named Executive Officers during fiscal year 2006 are shown in the Grants of Plan-Based Awards Table below. Additional information on these grants, including the number of shares subject to each grant, also is shown in the Grants of Plan-Based Awards Table. Previous awards and grants, whether vested or unvested, have no impact on the current year's awards and grants unless otherwise determined by our compensation committee.

Founders Shares. On October 3, 2005, prior to our IPO, Holdings II acquired all the capital stock of EXCO Holdings and subsequently merged into EXCO Holdings pursuant to the terms of an equity buyout, or Equity Buyout. Upon its formation in September 2005, Holdings II issued 3,333,330 shares of common stock to its founders, which only included members of our management and certain other employees at the time of issuance, for $0.01 per share. This group of founders included all but one of our Named Executive Officers, including Mr. Douglas H. Miller, who purchased 1,655,000 shares, Mr. Stephen F. Smith, who purchased 333,330 shares, Dr. J. Douglas Ramsey, who purchased 166,670 shares (these shares were issued to a limited partnership in which Dr. Ramsey owns a 97.2% limited partnership interest), and Mr. Harold L. Hickey, who purchased 166,670 shares. Each of these Named

Executive Officers and many of our employees also exchanged shares of EXCO Holdings common stock for Holdings II common stock or purchased additional shares of Holdings II common stock for cash in the Equity Buyout. This issuance of shares to the founders of Holdings II was part of our compensation philosophy to encourage our key employees to maximize shareholder value by ensuring that a significant portion of their total compensation was "at risk" in the form of equity compensation.

Retirement and Other Benefit Plans

401(k) Plans. All of our employees are eligible to participate in a 401(k) plan, either the EXCO Resources, Inc. Employees Savings Trust or the North Coast Energy, Inc. Employees' Profit Sharing Trust and Plan. We match up to 100% of employee contributions to the 401(k) plans based on years of service with us. In addition, our employees may select our common stock as an investment option under the 401(k) plans, up to a maximum of 50% of their contribution.

Severance Plan. The Second Amended and Restated Severance Plan, or the Severance Plan, is applicable to all of our employees in the event of a change of control. The Severance Plan provides for the payment of severance equal to one year of an employee's base salary in the event the employee's employment is terminated or there is an adverse change in the employee's job or compensation within six months following a change of control, as defined in the Severance Plan.

Other Benefits Plans. We offer a variety of health and benefit programs to all employees, including medical, dental, vision, life insurance and disability insurance. Our Named Executive Officers are generally eligible to participate in these employee benefit plans on the same basis as the rest of our employees.

Perquisites and Other Personal Benefits

We provide our Named Executive Officers with perquisites and other personal benefits that the compensation committee believes are reasonable and consistent with our overall compensation program. Mr. Douglas H. Miller's administrative assistant spends approximately 5% of her time on Mr. Miller's personal matters. Mr. Stephen F. Smith is a resident of Houston, Texas. We provide a corporate apartment for Mr. Smith in Dallas, Texas and we reimburse all of his business commuting expenses for travel between Houston and Dallas. On limited occasions, executives authorized to use a chartered aircraft for business travel are allowed to bring family members or guests along on the trip. Since we reimburse for use of the aircraft only for business travel and we pay for the aircraft based on the flight hours regardless of the passenger load, there is no incremental direct operating cost to us for the additional passengers. The compensation committee periodically reviews the levels of perquisites and other personal benefits provided to Named Executive Officers.

Attributed costs of the personal benefits described above for the Named Executive Officers for the fiscal year ended December 31, 2006, are included in the Summary Compensation Table under the heading "All Other Compensation."

Tax and Accounting Implications

Deductibility of Executive Compensation

As part of its role, the compensation committee reviews and considers the deductibility of executive compensation under Section 162(m) of the Internal Revenue Code, which provides that we may not deduct compensation of more than $1,000,000 that is paid to certain individuals. We believe that compensation paid under our incentive plans is generally fully deductible for federal income tax purposes. However, in the future, the compensation committee may approve compensation that will not meet these requirements in order to ensure competitive levels of total compensation for our executive officers.

Nonqualified Deferred Compensation

On October 22, 2004, the American Jobs Creation Act of 2004 was signed into law, changing the tax rules applicable to nonqualified deferred compensation arrangements. While the final regulations have not yet become effective, we believe we are operating in good faith compliance with the statutory provisions which were effective January 1, 2005.

Accounting for Stock-Based Compensation

Holdings II adopted the provisions of SFAS No. 123(R) upon its formation in August 2005. Upon closing of the merger of Holdings II with and into EXCO Holdings, we adopted SFAS No. 123(R).

Compensation of Executive Officers

The total compensation paid for the 2006 fiscal year to the Chief Executive Officer, Mr. Douglas H. Miller, Chief Financial Officer, Mr. J. Douglas Ramsey, Ph.D., and the other three most highly paid executive officers who received cash compensation in excess of $100,000 for the fiscal year ended December 31, 2006 (collectively, the "Named Executive Officers"), is set forth below in the following Summary Compensation Table:

2006 FISCAL YEAR SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)	Option Awards ($)(1)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)(2)(3)	Total ($)
Douglas H. Miller. . . . . *Chairman and Chief Executive Officer*	2006	600,000	120,000	—	1,055,116	—	—	20,000	1,795,116
Stephen F. Smith . . . . . *Vice Chairman and President*	2006	400,000	80,000	—	274,043	—	—	43,191(4)	797,234
J. Douglas Ramsey, Ph.D. *Vice President, Chief Financial Officer and Treasurer*	2006	300,000	60,000	—	136,783	—	—	15,000	511,783
Harold L. Hickey . . . . . *Vice President and Chief Operating Officer*	2006	300,000	60,000	—	136,783	—	—	16,000	512,783
William L. Boeing(5) . . *Vice President, General Counsel and Secretary*	2006	262,500	52,500	—	910,827(6)	—	—	—	1,225,827

(1) Reflects the dollar amount expensed for financial statement reporting for the year ended December 31, 2006 in accordance with SFAS No. 123(R), with the exception that the amount shown on the Summary Compensation Table assumes no forfeitures. Share-based compensation expense consists of stock options granted in and prior to 2006. Assumptions used in the calculation of these amounts are included in "Note 2. Summary of significant accounting policies—stock options" and "Note 14. Stock transactions" to our audited financial statements for the fiscal year ended December 31, 2006 included in our Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 19, 2007.

(2) The amounts shown in this column reflect, for each Named Executive Officer, matching contributions allocated by us to each of the Named Executive Officers pursuant to the EXCO Resources, Inc. Employees Savings Trust as follows: Mr. Miller—$20,000; Mr. Smith—$4,000; Mr. Ramsey—$15,000; and Mr. Hickey—$16,000. Mr. Boeing was not eligible for a matching contribution in 2006. He will be eligible for an initial matching contribution in 2007. We maintain suites at the American Airlines Center in Dallas, Texas and at the Rangers Ballpark in Arlington, Texas for sporting events and other entertainment purposes. We have not included any amounts related to the suites as a perquisite because tickets to the suites are available to all of our employees on a non-discriminatory basis, with

business entertainment purposes having priority as to use. We also did not include any amounts related to the use by Mr. Miller of his administrative assistant for personal matters because the incremental cost to us of the estimated 5% of Mr. Miller's administrative assistant's time spent on his personal matters, together with the value of any other perquisites received by Mr. Miller, is less than $10,000.

(3) Mr. Miller owns an aircraft through DHM Aviation, LLC. During 2006, we reimbursed DHM Aviation for our corporate use of the aircraft. We have not included any amounts related to the aircraft as a perquisite because all travel that is reimbursed by us is restricted to travel that is integrally and directly related to performing the executive's job and the amounts paid to DHM Aviation are below the market rate for the charter of similar aircraft. On limited occasions, employees authorized to use the aircraft for business travel are allowed to bring family members or guests along on the trip provided they have the prior approval of our president and our chief financial officer. Since we reimburse for use of the aircraft only for business travel and we pay for the aircraft based on the flight hours regardless of the passenger load, there is no incremental direct operating cost to us for the additional passengers. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—Transactions with Related Persons—Corporate use of personal aircraft" for additional information on amounts paid to DHM Aviation.

(4) Mr. Smith is a resident of Houston, Texas. We provide a corporate apartment for Mr. Smith in Dallas, Texas and we reimburse all of his business commuting expenses for travel between Houston and Dallas. During 2006, we paid an aggregate of $32,121 to Mr. Smith for the corporate apartment and $7,070 for commuting expenses.

(5) Mr. Boeing joined us as Vice President, General Counsel and Secretary in April 2006. Mr. Boeing's yearly salary is $350,000. The salary and cash bonus amounts for 2006 reflect his partial year of service. Prior to joining us, Mr. Boeing was a partner at Haynes and Boone, LLP. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—Transactions with Related Persons—Haynes and Boone, LLP" for information regarding our relationship with Haynes and Boone.

(6) Includes $875,343 for 500,000 option shares granted to Mr. Boeing when he joined us as Vice President, General Counsel and Secretary in April 2006 and $35,484 for 26,200 option shares granted in conjunction with our year-end 10% option bonus grant made to all company employees, which represent the amounts recognized for each of these awards for financial statement reporting purposes with respect to the fiscal year in accordance with FAS 123(R).

See "—Compensation Discussion and Analysis—Executive Compensation Components—Base Salary" for a discussion of the 2007 base salaries of our Named Executive Officers.

Equity Incentive Awards

The following table sets forth information regarding the plan-based awards under the EXCO Resources, Inc. 2005 Long-Term Incentive Plan granted to each Named Executive Officer during the fiscal year ended December 31, 2006:

2006 FISCAL YEAR GRANTS OF PLAN-BASED AWARDS

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units	All Other Option Awards: Number of Securities Underlying Options	Exercise or Base Price of Option Awards	Grant Date Fair Value of Stock and Option Awards(3)
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)	(#)	(#)	($/ Share)	
Douglas H. Miller . . . . . . *Chairman and Chief Executive Officer*	12/1/2006	—	—	—	—	—	—	—	60,000(1)	$14.62	$ 300,600
Stephen F. Smith. . . . . . . *Vice Chairman and President*	12/1/2006	—	—	—	—	—	—	—	40,000(1)	$14.62	$ 200,400
J. Douglas Ramsey, Ph.D. *Vice President, Chief Financial Officer and Treasurer*	12/1/2006	—	—	—	—	—	—	—	30,000(1)	$14.62	$ 150,300
Harold L. Hickey . . . . . . *Vice President and Chief Operating Officer*	12/1/2006	—	—	—	—	—	—	—	30,000(1)	$14.62	$ 150,300
William L. Boeing.	4/5/2006	—	—	—	—	—	—	—	500,000(2)	$12.36	$2,015,000
Vice President, General Counsel and Secretary .	12/1/2006	—	—	—	—	—	—	—	26,200(1)	$14.62	$ 131,262

(1) This grant was made in conjunction with our year-end 10% option bonus grant made to all company employees. See "—Compensation Discussion and Analysis—2006 Executive Compensation Components—Long-Term Incentive Compensation—2005 Long-Term Incentive Plan" for a discussion of this option bonus grant.

(2) The 500,000 option shares were granted to Mr. Boeing when he joined us as Vice President, General Counsel and Secretary in April 2006.

(3) The amounts included in the "Grant Date Fair Value of Stock and Option Awards" column represent the grant date fair value of the awards computed in accordance with SFAS No. 123(R). Assumptions used in the calculation of these amounts are included in "Note 2. Summary of significant accounting policies—stock options" and "Note 14. Stock transactions" to our audited financial statements for the fiscal year ended December 31, 2006 included in our Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 19, 2007. The value ultimately realized by the executive upon the actual exercise of the stock options may or may not be equal to the SFAS No. 123(R) determined value.

The following table sets forth information regarding the outstanding equity awards held by our Named Executive Officers as of December 31, 2006:

2006 FISCAL YEAR OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
Douglas H. Miller	852,500	852,500	—	$ 7.50	10/5/2015	—	—	—	—
Chairman and Chief Executive Officer	15,000	45,000	—	$14.62	12/1/2016	—	—	—	—
Stephen F. Smith	191,650	191,650	—	$ 7.50	10/5/2015	—	—	—	—
Vice Chairman and President	10,000	30,000	—	$14.62	12/1/2016	—	—	—	—
J. Douglas Ramsey, Ph.D.	83,350	83,350	—	$ 7.50	10/5/2015	—	—	—	—
Vice President, Chief Financial Officer and Treasurer	7,500	22,500	—	$14.62	12/1/2016	—	—	—	—
Harold L. Hickey	83,350	83,350	—	$ 7.50	10/5/2015	—	—	—	—
Vice President and Chief Operating Officer	7,500	22,500	—	$14.62	12/1/2016	—	—	—	—
William L. Boeing	125,000	375,000	—	$12.36	4/5/2016	—	—	—	—
Vice President, General Counsel and Secretary	6,550	19,650	—	$14.62	12/1/2016	—	—	—	—

None of our Named Executive Officers exercised any stock options during 2006. As a result, we have not included a table showing 2006 option exercises.

Nonqualified Defined Contribution and Other Nonqualified Deferred Compensation Plans

We do not provide any nonqualified defined contribution or other deferred compensation plans for our Named Executive Officers.

Potential Payments Upon Termination or Change-in-Control

On November 8, 2006, the Board of Directors approved the Second Amended and Restated EXCO Resources, Inc. Severance Plan, which we refer to as the "Severance Plan." The Severance Plan provides for the payment of severance in the event the employee's employment is terminated or there is an adverse change in the employee's job or compensation, as more specifically described in the Severance Plan, within six months following a change of control of EXCO. The plan is administered by our compensation committee, which has the sole discretion to determine whether an employee's termination of employment is eligible for payment of severance. All of our regular, full-time employees are eligible to participate in and receive benefits under the Severance Plan.

A change of control is defined as the occurrence of any of the following: (i) we are merged or consolidated into or with another entity, and as a result less than a majority of the combined voting power of the surviving entity is held by the holders of our voting stock prior to the merger; (ii) we sell or otherwise transfer all or substantially all of our assets to any person or entity if less than a majority of the combined voting power of such person or entity immediately after such sale or transfer is held by the holders of our voting stock prior to such sale or transfer; (iii) any person is or becomes the beneficial owner, directly or indirectly, of more than 50% of our total voting power; (iv) individuals who on the effective date of the Severance Plan constituted our Board of Directors and their successors that are appointed by the Board of Directors, cease for any reason to constitute a majority of the Board of Directors; or (v) the adoption of a plan relating to the liquidation or dissolution of us. The definition of "change of control" specifically excludes an event in which any subsidiary of EXCO is spun off by means of a rights offering to EXCO's shareholders or an underwritten public offering, or any combination thereof, even where less than a majority of the voting equity ownership is retained by EXCO.

Severance payment will be made only if the employee fully executes a release form with the plan administrator, to release and forever discharge us from any and all liability which the employee may have against us as a result of employment with or subsequent termination from us. Severance payment is equal to one year of an employee's base salary, offset by any other severance pay or other income replacement, to be paid in cash in a lump sum within fourteen days following receipt by us of an executed release form.

Mr. Boeing's offer letter related to his employment with us included a reference to a severance arrangement for him with the details to be mutually agreed upon at a later time. Mr. Boeing subsequently agreed to relinquish any rights to severance under such letter, other than in accordance with the terms of the Severance Plan. Mr. Boeing is still eligible to participate in the Severance Plan.

The following tables show, as of December 31, 2006, potential payments to our Named Executive Officers for various scenarios involving a change of control, death or disability, using, where applicable, the closing price of our common stock of $16.91 (as reported on the NYSE as of December 29, 2006). The footnotes listed below the tables apply to all of the tables in this section.

Douglas H. Miller
Chairman and Chief Executive Officer

Executive Benefits and Payments Upon Termination	Termination for Cause or Misconduct Within Six Months After a Change of Control ($)	Termination Not for Cause or Misconduct Within Six Months After a Change of Control ($)(1)	Change of Control (No Termination) ($)	Death ($)	Disability ($)
Compensation					
Severance(2)	—	600,000	—	—	—
Long-term Equity Incentives— Stock Options(3)	8,125,075	8,125,075	8,125,075	8,125,075	8,125,075
Total	8,125,075	8,725,075	8,125,075	8,125,075	8,125,075

Stephen F. Smith
Vice Chairman and President

Executive Benefits and Payments Upon Termination	Termination for Cause or Misconduct Within Six Months After a Change of Control ($)	Termination Not for Cause or Misconduct Within Six Months After a Change of Control ($)(1)	Change of Control (No Termination) ($)	Death ($)	Disability ($)
Compensation					
Severance(2)	—	400,000	—	—	—
Long-term Equity Incentives—					
Stock Options(3)	1,872,127	1,872,127	1,872,127	1,872,127	1,872,127
Total	1,872,127	2,272,127	1,872,127	1,872,127	1,872,127

J. Douglas Ramsey, Ph.D.
Vice President, Chief Financial Officer and Treasurer

Executive Benefits and Payments Upon Termination	Termination for Cause or Misconduct Within Six Months After a Change of Control ($)	Termination Not for Cause or Misconduct Within Six Months After a Change of Control ($)(1)	Change of Control (No Termination) ($)	Death ($)	Disability ($)
Compensation					
Severance(2)	—	300,000	—	—	—
Long-term Equity Incentives—					
Stock Options(3)	835,849	835,849	835,849	835,849	835,849
Total	835,849	1,135,849	835,849	835,849	835,849

Harold L. Hickey
Vice President and Chief Operating Officer

Executive Benefits and Payments Upon Termination	Termination for Cause or Misconduct Within Six Months After a Change of Control ($)	Termination Not for Cause or Misconduct Within Six Months After a Change of Control ($)(1)	Change of Control (No Termination) ($)	Death ($)	Disability ($)
Compensation					
Severance(2)	—	300,000	—	—	—
Long-term Equity Incentives—					
Stock Options(3)	835,849	835,849	835,849	835,849	835,849
Total	835,849	1,135,849	835,849	835,849	835,849

William L. Boeing
Vice President, General Counsel and Secretary

Executive Benefits and Payments Upon Termination	Termination for Cause or Misconduct Within Six Months After a Change of Control ($)	Termination Not for Cause or Misconduct Within Six Months After a Change of Control ($)(1)	Change of Control (No Termination) ($)	Death ($)	Disability ($)
Compensation					
Severance(2)	—	350,000	—	—	—
Long-term Equity Incentives—					
Stock Options(3)	1,751,249	1,751,249	1,751,249	1,751,249	1,751,249
Total	1,751,249	2,101,249	1,751,249	1,751,249	1,751,249

(1) The officer shall not be eligible to receive a severance payment if either (i) he receives a comparable offer of employment from any other operation of EXCO or any of its affiliate organizations, regardless of whether he accepts such offer or (ii) he receives and accepts a transfer of employment to any other operation of EXCO or any of its affiliate organizations.

(2) Assumes a payment equal to 100% of the officer's annual base salary.

(3) Pursuant to the terms of each stock option award, all options become fully vested automatically upon a change of control or upon the death or the total and permanent disability of the officer.

Director Compensation

The following table provides compensation information for the one year period ended December 31, 2006 for each non-employee member of our Board of Directors:

2006 FISCAL YEAR DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Jeffrey D. Benjamin	85,000	—	—	—	—	—	85,000
Earl E. Ellis	45,000	—	—	—	—	—	45,000
Robert H. Niehaus	40,000	—	—	—	—	—	40,000
Boone Pickens	25,000	—	—	—	—	—	25,000
Robert L. Stillwell	40,000	—	—	—	—	—	40,000

Cash Compensation. Our non-employee directors are paid a retainer of $25,000 per year. The chair of each committee is paid an additional $10,000 per year, other than the chair of the audit committee who is paid an additional $50,000 per year. Each other committee member is paid an additional $5,000 per year. We pay no additional remuneration to our employees serving as directors. All directors, including our employee directors, are reimbursed for reasonable out-of-pocket expenses incurred in connection with their attendance at meetings of the Board of Directors and committee meetings. We anticipate that cash compensation to directors in fiscal 2007 will be the same as that described above.

At its November 8, 2006 meeting, the Board of Directors adopted the 2007 Director Plan of EXCO Resources, Inc. (as amended, we refer to this plan as the "Payment Plan"). The Payment Plan permits the non-employee directors who receive fees for their service on the Board of Directors and its committees to make an annual election to receive their fees (i) entirely in cash, (ii) 50% in cash and 50% in our common stock, or (iii) entirely in our common stock. Due to certain regulatory reasons, Mr. Pickens will be paid in cash. All of our other non-employee directors have elected to receive their fees for service during 2007 entirely in our common stock. All director fees are paid on a quarterly basis on the first business day following the end of each fiscal quarter. Payments in the form of our common stock are issued as of the payment date, which is the first business day following the end of the fiscal quarter, at the closing price of the our common stock on the NYSE on that date.

The Payment Plan also permits non-employee directors to defer the payment of his or her director fees (employee directors do not receive fees in their capacity as directors), beginning with director fees earned in 2007. Directors may defer the payment of director fees, whether payable in the form of cash or our common stock, to (i) a specified date, (ii) his or her termination of service, (iii) the occurrence of a change of control, or (iv) the earlier of two or more of those events. This deferral is qualified to satisfy the requirements of Section 409A of the Internal Revenue Code of 1986.

The Payment Plan also provides that upon the appointment or election to the Board of Directors of a new director, the new director will receive an automatic one-time grant of an option to purchase 50,000 shares of our common stock, in addition to the other fees they will earn as a director. The grant date will be the date of appointment or election and the exercise price will be set at the closing price of our common stock on the NYSE. The option will have a term of ten years, with 25% of the shares subject to the option (12,500 shares) vesting immediately and the balance vesting in equal proportions on the next three anniversary dates. No shares will vest, and such shares will be forfeited, in any fiscal year in which the director attends less than 75% of the Board of Directors meetings held for that fiscal year. In the event a director ceases to serve for any reason, the unvested shares subject to the option shall be forfeited. However, this option will be subject to acceleration upon a change of control as defined under the EXCO Resources, Inc. 2005 Long-Term Incentive Plan. All shares issuable under the Payment Plan, including pursuant to any option granted thereunder, shall be deemed issued under the terms of the EXCO Resources, Inc. 2005 Long-Term Incentive Plan.

Compensation Committee Report on Executive Compensation

Our compensation committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the compensation committee recommended to our board of directors that the Compensation Discussion and Analysis be included in this Amendment No. 1 on Form 10-K/A.

The foregoing report is provided by the following directors, who constitute the compensation committee.

COMPENSATION COMMITTEE

Robert L. Stillwell, Chairman
Jeffrey D. Benjamin
Earl E. Ellis
Robert H. Niehaus

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended December 31, 2006, the compensation committee was comprised of Messrs. Stillwell (chair), Benjamin, Ellis and Niehaus.

No member of our compensation committee is or has been an officer or employee of us or any of our subsidiaries or had any relationship requiring disclosure pursuant to Item 404 of Regulation S-K during the fiscal year ended December 31, 2006. None of our executive officers served as a director or member of the compensation committee (or other board committee performing similar functions or, in the absence of any such committee, the entire board of directors) of another entity, one of whose executive officers served on our compensation committee or as one of our directors.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Equity Compensation Plan Information

The following table provides certain information as of December 31, 2006 with respect to our equity compensation plans under which our equity securities are authorized for issuance:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	8,267,373	$10.32	1,574,475
Equity compensation plans not approved by security holders	Not applicable	Not applicable	Not applicable
Total	8,267,373	$10.32	1,574,475

Principal Shareholders

The following tables set forth as of April 3, 2007 the number and percentage of shares of our common stock and Convertible Preferred Stock of the Company beneficially owned by:

- each person known by us to beneficially own more than 5% of the outstanding shares of our common stock or 5% of the outstanding shares of Convertible Preferred Stock;
- each of our directors;
- each of our named executive officers; and
- all of our directors and executive officers as a group.

Beneficial ownership is determined in accordance with the rules of the SEC. Beneficial ownership information is based on the most recent Forms 3, 4 and 5 and Schedules 13D and 13G filings with the SEC and reports made directly to us. In computing the number of shares beneficially owned by a person and the percentage ownership of that person, shares of common stock subject to options held by that person that are currently exercisable or exercisable within 60 days of April 3, 2007 and shares of common stock issuable upon conversion of Convertible Preferred Stock are deemed outstanding, but are not deemed outstanding for computing the percentage ownership of any other person. Percentage of beneficial ownership of our common stock is based upon 104,241,415 shares of common stock outstanding as of

April 3, 2007. Percentage of beneficial ownership of Convertible Preferred Stock is based upon 39,008 shares of Convertible Preferred Stock outstanding as of April 3, 2007. To our knowledge, except as set forth in the footnotes to this table and subject to applicable community property laws, each person named in the table has sole voting and investment power with respect to the shares set forth opposite such person's name. Unless otherwise indicated in a footnote, the address for each individual listed below is c/o EXCO Resources, Inc., 12377 Merit Drive, Suite 1700, Dallas, Texas 75251.

Beneficial owner	Shares of Common Stock(1)	Percentage of Common Stock outstanding	Shares of Convertible Preferred Stock	Percentage of Convertible Preferred Stock outstanding
Holders of more than 5%				
BP EXCO Holdings II LP(2) 8117 Preston Road Suite 260W Dallas, TX 75225	13,193,722	12.7%	—	—
Oaktree Capital Management, LLC(3) 333 S. Grand Avenue, 28th Floor Los Angeles, CA 90071	9,370,394	8.5%	11,700	30.0%
FMR Corp.(4) 82 Devonshire Street Boston, MA 02109	9,328,867	8.9%	1,952	5.0%
Ares Corporate Opportunities Fund(5) Ares Corporate Opportunities Fund II, L.P. c/o Ares Management LLC 1999 Avenue of the Stars Suite 1900 Los Angeles, CA 90067	8,085,307	7.6%	2,925	7.5%
Cyrus Capital Partners, LP(6) 390 Park Avenue, 21st Floor New York, NY 10022	1,026,842	1.0%	1,951	5.0%
American International Group, Inc.(7) 70 Pine Street New York, New York 10270	1,026,842	1.0%	1,951	5.0%

(1) Includes the shares of our common stock into which the shares of Convertible Preferred Stock shown in the "Shares of Convertible Preferred Stock" column are convertible. The Convertible Preferred Stock is convertible at any time at the holder's election into a number of shares of our common stock equal to the quotient of the then-current liquidation preference divided by the then-current conversion price. Initially, the liquidation preference is $10,000 per share and the conversion price is $19.00 per share, which equates to each share of Convertible Preferred Stock being initially convertible into approximately 526.3 shares of our common stock, subject to adjustment for fractional shares. The Convertible Preferred Stock also votes with our common stock on all matters, other than the election of directors, on an as converted basis.

(2) Includes 388,889 shares of our common stock held by BP EXCO Holdings, LP.

(3) Includes 3,142,400 shares of our common stock held by OCM Principal Opportunities Fund III, L.P. ("Fund III"), 57,600 shares of our common stock held by OCM Principal Opportunities Fund IIIA,

L.P. ("Fund IIIA"), 5,850 shares of Convertible Preferred Stock held by OCM Principal Opportunities Fund IV, L.P. ("Fund IV") and 5,850 shares of Convertible Preferred Stock held by OCM EXCO Holdings, LLC ("OCM EXCO"). Oaktree Capital Management, LLC ("Oaktree") is (i) managing member of OCM Principal Opportunities Fund III GP, LLC ("Fund III GP"), (ii) sole director of OCM Principal Opportunities Fund IV GP Ltd. ("Fund IV GP Ltd."), (iii) manager of OCM EXCO and (iv) investment manager of Fund III, Fund VI A and Fund IV. Fund III GP is the general partner of Fund III and Fund IIIA. Fund IV GP Ltd. is the general partner of OCM Principal Opportunities Fund IV GP, L.P., which is the general partner of Fund IV.

Oaktree is a limited liability company managed by an executive committee, the members of which are Howard S. Marks, Bruce A. Karsh, Sheldon M. Stone, D. Richard Masson, Larry W. Keele, Stephen A. Kaplan, John B. Frank, David Kirchheimer and Kevin L. Clayton. Each such person disclaims beneficial ownership of the securities listed, except to the extent of any pecuniary interest therein.

Also includes 12,500 shares which represent the vested portion of a stock option to purchase 50,000 shares of our common stock issued to Mr. Cebula, a Managing Director of Oaktree, as an initial grant upon becoming one of our directors in March 2007 pursuant to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc. This stock option is held directly by Mr. Cebula for the benefit of the Oaktree Funds. Pursuant to the policies of Oaktree, Mr. Cebula must hold this stock option on behalf of and for the sole benefit of the Oaktree Funds and is assigning all economic, pecuniary, and voting rights to the Oaktree Funds. Mr. Cebula disclaims beneficial ownership of these securities, except to the extent of any indirect pecuniary interest therein.

(4) Fidelity Management & Research Company ("Fidelity"), a wholly-owned subsidiary of FMR Corp. and an investment adviser registered under Section 203 of the Investment Advisers Act of 1940, is the beneficial owner of 8,398,815 shares, or 8.0%, of our outstanding common stock as a result of acting as investment adviser to various investment companies registered under Section 8 of the Investment Company Act of 1940. The number of shares of our common stock owned by the investment companies includes 1,027,367 shares of Common Stock resulting from the assumed conversion of 1,952 shares of Convertible Preferred Stock. The number of shares of our common stock owned by the investment companies does not include 4,235,788 shares of common stock resulting from the conversion of 8,048 shares of Hybrid Preferred Stock. If such shares of common stock issuable upon conversion of the Hybrid Preferred Stock were included, then Fidelity would be the beneficial owner of 1,264,603 shares, or 11.5%, of our outstanding common stock.

Edward C. Johnson 3d and FMR Corp., through its control of Fidelity, and the funds each has sole power to dispose of the 8,398,815 shares owned by the funds.

Members of the family of Edward C. Johnson 3d, Chairman of FMR Corp., are the predominant owners, directly or through trusts, of Series B shares of common stock of FMR Corp., representing 49% of the voting power of FMR Corp. The Johnson family group and all other Series B shareholders have entered into a shareholders' voting agreement under which all Series B shares will be voted in accordance with the majority vote of Series B shares. Accordingly, through their ownership of voting common stock and the execution of the shareholders' voting agreement, members of the Johnson family may be deemed, under the Investment Company Act of 1940, to form a controlling group with respect to FMR Corp.

Neither FMR Corp. nor Edward C. Johnson 3d, Chairman of FMR Corp., has the sole power to vote or direct the voting of the shares owned directly by the Fidelity Funds, which power resides with the Funds' Boards of Trustees. Fidelity carries out the voting of the shares under written guidelines established by the Funds' Boards of Trustees.

Fidelity Management Trust Company, a wholly-owned subsidiary of FMR Corp. and a bank as defined in Section 3(a)(6) of the Securities Exchange Act of 1934, is the beneficial owner of 109,200 shares of our outstanding common stock as a result of its serving as investment manager of the institutional account(s). Edward C. Johnson 3d and FMR Corp., through its control of Fidelity Management Trust Company, each has sole dispositive power and sole power to vote or to direct the voting of these shares.

Pyramis Global Advisors Trust Company ("PGATC"), 53 State Street, Boston, Massachusetts, 02109, an indirect wholly-owned subsidiary of FMR Corp. and a bank as defined in Section 3(a)(6) of the Securities Exchange Act of 1934, is the beneficial owner of 591,105 shares, or 0.6%, of our outstanding common stock as a result of its serving as investment manager of institutional accounts owning such shares. The number of shares of our common stock owned by the institutional account(s) includes 82,105 shares of our common stock resulting from the assumed conversion of 156 shares of Convertible Preferred Stock. The number of shares of our common stock owned by the institutional accounts does not include 338,947 shares of common stock resulting from the conversion of 644 shares of Hybrid Preferred Stock. If such shares of common stock issuable upon conversion of the Hybrid Preferred Stock were included, then PGATC would be the beneficial owner of 930,052 shares, or 0.8%, of our outstanding common stock. Edward C. Johnson 3d and FMR Corp., through its control of PGATC, each has sole dispositive power and sole power to vote or to direct the voting of these shares.

(5) Includes 6,533,333 shares of our common stock held by Ares Corporate Opportunities Fund, L.P. ("ACOF") and an aggregate of 1,539,474 shares of our common stock initially issuable upon conversion of 2,925 shares of Convertible Preferred Stock held by ACOF (together with certain affiliated co-investing entities) and Ares Corporate Opportunities Fund II, L.P. (together with certain affiliated co-investing entities) (collectively, the "ACOF Investors"). ACOF Management, L.P. ("ACOF Management") is the general partner of ACOF (and its affiliated co-investing entities). ACOF Management II, L.P. ("ACOF Management II") is the general partner of ACOF II (and its affiliated co-investing entities). ACOF Operating Manager, L.P. ("ACOF Operating") is the general partner of ACOF Management and the manager of ACOF. ACOF Operating Manager II, L.P., ("ACOF Operating II") is the general partner of ACOF Management II and the manager of ACOF II. Ares Inc. is the general partner of ACOF Operating and ACOF Operating II. Ares Management LLC ("Ares Management") indirectly owns 100% of the limited partnership interests of ACOF Operating Manager and ACOF Operating Manager II. Ares Partners Management Company, LLC ("Ares Partners"), directly or indirectly owns all of the outstanding capital stock of Ares Inc. and Ares Management. Each of the members of Ares Partners has the right to receive distributions in respect of the sale of investments by the entities named above, including the shares of our common stock and the Convertible Preferred Stock, in accordance with their membership interests in Ares Partners. Under applicable law, certain of these members and their respective spouses (where applicable) may be deemed to be beneficial owners having indirect ownership of the securities owned of record by the ACOF Investors by virtue of such status. Each of the entities named above (other than the ACOF Investors) and the members of Ares Partners and their respective spouses (where applicable) disclaim beneficial ownership of all securities reported herein.

Also includes 12,500 shares of our common stock, which represents the vested portion of stock options to acquire 50,000 shares of our common stock which were issued to one of our directors, Jeffrey Serota, as an initial grant pursuant to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc. upon becoming one of our directors in March 2007. These stock options are held by Mr. Serota for the benefit of Ares Management and certain funds managed by or affiliated with Ares Management (collectively, the "Ares Entities"). Pursuant to the policies of the Ares Entities, Mr. Serota holds these stock options as a nominee for the sole benefit of the Ares Entities and has assigned all economic, pecuniary and voting rights to the Ares Entities. Mr. Serota disclaims beneficial ownership of these securities.

(6) Cyrus Capital Partners LP, a registered investment advisor, is the investment manager for the following shareholders: 1,648 shares of Convertible Preferred Stock held by Cyrus Opportunities Master Fund II, Ltd., 49 shares of Convertible Preferred Stock held by Cyrus Short Credit Master Fund, Ltd. and 254 shares of Convertible Preferred Stock held by CRS Fund, Ltd.

(7) Includes 137 shares of Convertible Preferred Stock held by AIG Annuity Insurance Company, 49 shares of Convertible Preferred Stock held by Merit Life Insurance Co., 156 shares of Convertible Preferred Stock held by AIG Life Insurance Company, 156 shares of Convertible Preferred Stock held by American International Life Assurance Company of New York, 59 shares of Convertible Preferred Stock held by American General Assurance Company, 105 shares of Convertible Preferred Stock held by The United States Life Insurance Company, 16 shares of Convertible Preferred Stock held by American International Group, Inc. Retirement Plan, 316 shares of Convertible Preferred Stock held by The Variable Annuity Life Insurance Company and 758 shares of Convertible Preferred Stock held by American General Life Insurance Company, each an affiliate of American International Group, Inc. Additionally, 199 shares of Convertible Preferred Stock are owned by certain open ended management investment companies for which AIG Global Investment Corp. ("AIGGIC") or AIG SunAmerica Asset Management Corp. (each a direct or indirect wholly owned subsidiary of American International Group, Inc.) acts as investment adviser or sub-adviser. AIGGIC, an SEC registered investment adviser, is a part of AIG Global Investment Group ("AIGGIG"). AIGGIG is comprised of a group of international companies (including AIGGIC), which provide investment advice and market asset management products and services to clients around the world.

Beneficial owner	Shares(1)	Options exercisable within 60 days	Percentage of shares outstanding
Named Executive Officers			
Douglas H. Miller(2)	5,429,473	867,500	5.2%
Stephen F. Smith(3)	791,116	201,650	*
J. Douglas Ramsey, Ph.D.(4)	774,125	90,850	*
William L. Boeing	256,550	256,550	*
Harold L. Hickey	348,525	90,850	*
Directors			
Jeffrey D. Benjamin(5)	488,284	25,000	*
Vincent D. Cebula(6)	12,500	12,500	*
Earl E. Ellis(7)	487,681	25,000	*
Robert H. Niehaus(8)	3,140,085	25,000	3.0%
Boone Pickens(9)	13,354,715	25,000	12.8%
Jeffrey S. Serota(10)	—	—	*
Robert L. Stillwell(11)	52,822	25,000	*
All executive officers and directors as a group (13 persons)	25,193,793	1,666,150	23.6%

(1) Includes the options exercisable within 60 days shown in the options column.

(2) Includes 562,916 shares of our common stock held in six trusts for the benefit of immediate family members.

(3) Includes 39,142 shares of our common stock held in two trusts for the benefit of immediate family members.

(4) Includes 614,309 shares of our common stock held by a limited partnership in which Dr. Ramsey holds a 97.2% limited partnership interest.

(5) Includes the right to acquire 1,281 shares of our common stock pursuant to the Payment Plan granted to Mr. Benjamin as deferred compensation in lieu of cash for his service on our board of directors and committees for the quarter ended March 31, 2007. These shares vest immediately and are to be settled in our common stock upon the earlier to occur of (1) as soon as administratively feasible after the date on which Mr. Benjamin incurs a "Termination of Service" under the Payment Plan and (2) upon the occurrence of a "Change in Control" under the Payment Plan. The number of shares are equal to the amount of compensation deferred under the Payment Plan divided by $16.60 which was the closing price for our common stock on April 2, 2007. See "Item 11. Executive Compensation—Director Compensation" for a discussion of the Payment Plan.

(6) These 12,500 shares represent the vested portion of a stock option to purchase 50,000 shares of our common stock issued to Mr. Cebula, a Managing Director of Oaktree, as an initial grant upon becoming one of our directors in March 2007 pursuant to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc. This stock option is held directly by Mr. Cebula for the benefit of the Oaktree Funds. Pursuant to the policies of Oaktree, Mr. Cebula must hold this stock option on behalf of and for the sole benefit of the Oaktree Funds and is assigning all economic, pecuniary, and voting rights to the Oaktree Funds. Mr. Cebula disclaims beneficial ownership of these securities, except to the extent of any indirect pecuniary interest therein. The shares reported for Mr. Cebula do not include 3,200,000 shares of our common stock, 11,700 shares of Series B Convertible Preferred Stock and 48,300 shares of Series A-1 Hybrid Preferred Stock, in each case, held directly by certain of the Oaktree Funds. Mr. Cebula disclaims beneficial ownership of these securities, except to the extent of any indirect pecuniary interest therein.

(7) Includes 678 shares of our common stock issued pursuant to the Payment Plan to Mr. Ellis in lieu of cash as compensation for his service on our board of directors and committees for the quarter ended March 31, 2007. See "Item 11. Executive Compensation—Director Compensation" for a discussion of the Payment Plan.

(8) Beneficial ownership consists of 1,450,018 shares of our common stock owned by Greenhill Capital Partners, L.P., 207,189 shares of our common stock owned by Greenhill Capital Partners (Cayman), L.P., 228,860 shares of our common stock owned by Greenhill Capital Partners (Executives), L.P., 458,415 shares of our common stock owned by Greenhill Capital, L.P., 753 shares of Convertible Preferred Stock owned by Greenhill Capital Partners II, L.P., 295 shares of Convertible Preferred Stock owned by Greenhill Capital Partners (Cayman) II, L.P., 52 shares of Convertible Preferred Stock owned by Greenhill Capital Partners (Executives) II, L.P., and 363 shares of Convertible Preferred Stock owned by Greenhill Capital Partners (Employees) II, L.P. By virtue of his ownership and management positions at the entities which control the Greenhill funds referred to in the preceding sentence, Mr. Niehaus may be deemed to beneficially own these shares. Mr. Niehaus disclaims beneficial ownership of these shares except to the extent of his pecuniary interest therein. Beneficial ownership also includes options held by Mr. Niehaus to purchase 25,000 shares of our common stock pursuant to the 2005 Long-Term Incentive Plan and 603 shares of our common stock directly held by Mr. Niehaus and issued pursuant to the Payment Plan to Mr. Niehaus in lieu of cash as compensation for his service on our board of directors and committees for the quarter ended March 31, 2007. See "Item 11. Executive Compensation—Director Compensation" for a discussion of the Payment Plan.

(9) Includes 388,889 shares of our common stock held by BP EXCO Holdings LP, 13,193,722 shares of our common stock held by BP EXCO Holdings II LP and 135,993 shares of our common stock held by

his wife, Madeleine Pickens. Mr. Pickens is the controlling member of BP EXCO Holdings GP, LLC, the general partner of BP EXCO Holdings II LP.

(10) In connection with Mr. Serota's appointment to our board of directors in March 2007, Mr. Serota was granted options to acquire 50,000 shares of our common stock. Options to acquire 12,500 of these shares vested on March 30, 2007. These stock options are held by Mr. Serota for the benefit of the Ares Entities. Pursuant to the policies of the Ares Entities, Mr. Serota holds these stock options as a nominee for the sole benefit of the Ares Entities and has assigned all economic, pecuniary and voting rights to the Ares Entities. Mr. Serota disclaims beneficial ownership of these securities. Amounts reported do not include the shares of our common stock and Convertible Preferred Stock referred to in note 5 to the beneficial ownership table for "holders of more than 5%" above, with respect to which Mr. Serota disclaims beneficial ownership.

(11) Includes the right to acquire 603 shares of our common stock pursuant to the Payment Plan granted to Mr. Stillwell as deferred compensation *in lieu of cash* for his service on our board of directors and committees for the quarter ended March 31, 2007. These shares vest immediately and are to be settled in our common stock upon the earlier to occur of (1) as soon as administratively feasible after the date on which Mr. Stillwell incurs a "Termination of Service" under the Payment Plan and (2) upon the occurrence of a "Change in Control" under the Payment Plan. The number of shares are equal to the amount of compensation deferred under the Payment Plan divided by $16.60 which was the closing price for our common stock on April 2, 2007. See "Item 11. Executive Compensation—Director Compensation" for a discussion of the Payment Plan.

* Less than 1%.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Transactions with Related Persons

TXOK acquisition

On September 27, 2005, BP EXCO Holdings LP acquired 150,000 shares of preferred stock of TXOK Acquisition, Inc., or TXOK, an affiliate of EXCO Holdings, for $150.0 million to partially fund our acquisition of ONEOK Energy Resources Company and ONEOK Energy Resources Holdings, L.L.C. Mr. Boone Pickens, one of our directors, is the controlling member of BP EXCO Holdings GP, LLC, the general partner of BP EXCO Holdings LP. In connection with the sale of the TXOK preferred stock, each of TXOK and EXCO Holdings agreed, if the proceeds of an initial public offering of its or its subsidiary's capital stock were not sufficient to redeem all of the TXOK preferred stock, to use its reasonable best efforts to redeem all of the TXOK preferred stock with available cash and borrowings under its credit facilities. On February 14, 2006, TXOK redeemed the TXOK preferred stock for $158.7 million in cash. In addition, the Company issued 388,889 shares of its common stock, or redemption shares, to an entity controlled by Mr. Pickens, as the redemption premium under the terms of the Amended and Restated Certificate of Incorporation of TXOK. The redemption shares were issued at a price of $12.00 per share in accordance with the redemption terms. Mr. Pickens holds over 98% of the partnership interests in BP EXCO Holdings LP. The terms of the TXOK preferred stock were negotiated on terms believed to be fair to EXCO Holdings in order to arrange interim equity financing pending completion of the IPO. The redemption shares were issued pursuant to an exemption from registration under Section 4(2) of the Securities Act and Regulation D promulgated thereunder. As a result of the redemption of the TXOK preferred stock, TXOK became a wholly-owned subsidiary of the Company.

TXOK also entered into a credit facility with an initial borrowing base of $325.0 million, and a second lien term loan facility of $200.0 million to fund the ONEOK acquisition. Approximately $308.8 million was drawn at the closing of the ONEOK acquisition. Neither EXCO Holdings nor EXCO Resources were an obligor or guarantor with respect to these financings; however, EXCO Holdings pledged its stock in TXOK as collateral security for payment of the TXOK credit facility and the TXOK term loan. On February 14, 2006, in connection with our IPO, the Company advanced TXOK $158.8 million to redeem its preferred stock and TXOK became a wholly-owned subsidiary.

Effective October 15, 2005, the Company entered into an intercompany agreement with TXOK to manage TXOK's business affairs. Prior to the IPO and the redemption of the TXOK preferred stock, Mr. Pickens controlled TXOK through BP EXCO Holdings LP's ownership of the TXOK preferred stock. The agreement provides that we will provide TXOK with general management, treasury, finance, legal, audit, tax, information technology, and payroll and benefit administration services. TXOK has agreed to reimburse us on a monthly basis for the total amount of compensation, taxes and benefits we provide to employees providing services to TXOK. TXOK has also agreed to pay us $25,000 per month for the additional services we provide, as well as reimbursement of all costs directly related to the operations of TXOK.

Equity Buyout

On October 3, 2005, Holdings II acquired all the capital stock of EXCO Holdings and subsequently merged into EXCO Holdings. Upon its formation, Holdings II issued 3,333,330 shares of common stock to its founders for $0.01 per share. This group of founders included Mr. Douglas H. Miller, who purchased 1,655,000 shares, Mr. Stephen F. Smith, who purchased 333,330 shares, Dr. J. Douglas Ramsey, who purchased 166,670 shares (these shares were issued to a limited partnership in which Dr. Ramsey owns a 97.2% limited partnership interest), and Mr. Harold L. Hickey, who purchased 166,670 shares, as well as a number of our employees. Each of these persons and many of our employees also exchanged shares of

EXCO Holdings common stock for Holdings II common stock or purchased additional shares of Holdings II common stock for cash pursuant to the terms of two stock purchase agreements.

The registration rights agreement

Overview. Each stockholder of Holdings II on October 3, 2005 entered into a registration rights agreement with Holdings II. These stockholders include Douglas H. Miller, Stephen F. Smith, J. Douglas Ramsey, Ph.D., Harold L. Hickey, Jeffrey D. Benjamin, Earl E. Ellis, Robert H. Niehaus, Boone Pickens and Robert L. Stillwell. The registration rights agreement was amended and restated pursuant to the terms and conditions of the First Amended and Restated Registration Rights Agreement, or the registration rights agreement. As a result of the merger of Holdings II with and into EXCO Holdings and upon consummation of the merger of EXCO Holdings into us, the registration rights agreement was assumed by us. The registration rights agreement entitles the EXCO Holdings stockholders to certain rights with respect to the registration of shares of our common stock for resale under the Securities Act.

Registrations. Pursuant to the registration rights agreement, after the IPO, all holders of unregistered shares of our common stock who are subject to the registration rights agreement can require us to register their shares in certain circumstances. In addition, at any time that we file a registration statement registering other shares, the holders of shares subject to the registration rights agreement can require that we include their shares in such registration statement, subject to certain exceptions.

At any time on or after 180 days after the completion of the IPO, any holder of unregistered shares of our common stock who is party to the registration rights agreement may request that we register up to one-third of the holder's registrable securities in a resale registration statement. At any time on or after 365 days after the completion of the IPO, any holder of registrable securities may again require us to register up to an additional one-third of the holder's registrable securities initially covered by the registration rights agreement in the same manner as the initial resale registration was made. A similar demand right will be invocable by any holder with respect to its remaining registrable securities commencing 540 days after completion of the IPO. Upon any such request for registration, we would then be required to give notice of the requested registration to all other holders of registrable securities to allow such other holders to register up to one-third of their registrable securities on the same registration statement. We may request in writing that J.P. Morgan Securities Inc. (or the lead underwriter and sole stabilization agent of the IPO, if other than J.P. Morgan Securities Inc.) waive the registration waiting periods and registration volume limitations on resale registrations described in this paragraph. Upon or without such a request, J.P. Morgan Securities Inc. (or such other underwriter), in its sole discretion and based upon its evaluation of market conditions, the historical trading activity and liquidity of our common shares and other considerations it deems relevant, may waive continued application of the registration waiting periods and registration volume limitations described in this paragraph.

If EXCO Holdings (or, after the merger of EXCO Holdings into us, we) at any time or from time to time proposes to register any of its securities under the Securities Act of 1933, as amended, or the Securities Act, other than in an initial public offering or registrations on Form S-4 or Form S-8, then all holders, or all former holders, of EXCO Holdings registrable securities, if such shares have not been previously registered, will be entitled to piggyback registration rights, allowing them to have their shares included in the registration. These piggyback registrations are subject to delay or termination of the registration in certain circumstances.

Postponements and limitations. Under certain circumstances, we may postpone a registration if our Board of Directors determines in good faith that effecting such a registration or continuing the disposition of common stock would have a material adverse effect on us, or would not be in our best interests. Furthermore, the underwriters of the registration may, subject to certain limitations, limit the number of shares included in the registration.

Founders common stock. The registration rights agreement provides, until the third anniversary of the registration rights agreement, that the holders of our common stock representing common stock of Holdings II issued prior to the Equity Buyout, or the founders, may only sell their common stock pursuant to an effective registration statement covering the resale of such founder's shares and may not sell their shares pursuant to Rule 144 or any other exemption from registration or otherwise.

Amendments and waivers. The provisions of the registration rights agreement may not be amended, terminated or waived without the written consent of us, of holders of a majority of the shares then held by the outside investors and holders of a majority of the shares then held by the management investors.

Holdback arrangements. Upon entering into the registration rights agreement, each holder of registrable securities agrees that, at the request of the sole or lead managing underwriter in an underwritten offering, it will not make any short sale of, loan, grant any option for the purchase of or effect any public sale or distribution, including a sale pursuant to Rule 144 under the Securities Act, of any registrable securities during the five days prior to, and the time period (up to 90 days) requested by the underwriter following an underwritten offering. The holders of registrable securities will be subject to these restrictions for 180 days following the effective date of the registration statement filed with respect to the IPO.

On January 17, 2007, our registration statement covering one-third of the shares that were subject to the registration statement was declared effective by the SEC. On January 11, 2007, J.P. Morgan Securities Inc. and EXCO executed a waiver letter that allows selling shareholders to request that we register for resale the remaining two-thirds of their shares at any time after February 14, 2007. On February 15, 2007, we received a request from one of our shareholders to register the remaining two-thirds of his shares in accordance with the registration rights agreement.

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. We believe 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 to us and our shareholders. As a result, reimbursed use of the aircraft is restricted to travel that is integrally and directly related to performing senior management's jobs. Such use must be approved in advance by our President and Chief Financial Officer. We maintain a detailed written log of such usage specifying the 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.

At least annually, and more frequently if requested by the audit committee or our Director of Internal Audit, 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 we 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 less than market rate for similar aircraft. In addition, DHM Aviation, LLC is reimbursed for customary out-of-pocket catering expenses invoiced for a flight and any reimbursement of out-of-pocket expenses for pilots.

We reimburse DHM Aviation, LLC at a rate of $3,600 per hour, including fuel surcharges, for use of the aircraft, plus expenses related to catering, crew meals and accommodations. During 2006, we reimbursed $532,253 to DHM Aviation, LLC for use of the aircraft.

Intercompany promissory note

On October 7, 2005, EXCO Resources agreed to provide a revolving line of credit for the benefit of its parent, EXCO Holdings, in an aggregate principal amount not to exceed $10.0 million. This indebtedness was evidenced by an intercompany promissory note, which bears interest at 7.0% per annum and matures on October 7, 2007. In conjunction with the closing of our IPO on February 14, 2006, EXCO Holdings was merged with and into EXCO Resources. As a result, the intercompany promissory note was repaid in full and terminated.

American Airlines Center suite

We maintain a suite at the American Airlines Center in Dallas, Texas. We share the suite with and are reimbursed for 50% of our 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 us and such entity. During the year ended December 31, 2006, we paid a total of $350,000 to maintain the suite for a one year lease from August 2006 to August 2007, of which $175,000 was reimbursed by the entity affiliated with Mr. Pickens.

Private placement of preferred stock

On March 30, 2007, we completed a private placement of an aggregate of 39,008 shares of 7.0% Preferred Stock for $390 million and 160,992 shares of Hybrid Preferred Stock for $1.61 billion to accredited investors. We refer to this transaction as the "private placement." In the private placement, we issued and sold 23,408 shares of Series A-1 7.0% Preferred Stock, 975 shares of Series A-2 7.0% Preferred Stock, 11,700 shares of Series B 7.0% Preferred Stock, 2,925 shares of Series C 7.0% Preferred Stock, 149,441 shares of Series A-1 Hybrid Preferred Stock and 11,551 shares of Series A-2 Hybrid Preferred Stock. The purchase price for each share of all series of preferred stock 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 pursuant to Section 4(2) thereof and Regulation D promulgated thereunder.

The $2.0 billion in cash proceeds from the private placement were used to make a $1.67 billion contribution to EXCO Partners, LP to close the acquisition of substantially all of the oil and natural gas properties, acreage and related assets, including hedges in respect of a significant portion of estimated production for 2007, 2008 and 2009, of Anadarko Petroleum Corporation and Anadarko Gathering Company in the Vernon and Ansley Fields located in Jackson Parish, Louisiana, to repay $262.5 million of indebtedness at EXCO Partners, LP, and, when combined with surplus cash, to reduce our outstanding revolving credit facility by $352.0 million and to pay offering expenses.

Several related parties participated in the transaction:

- Entities affiliated with Ares purchased 2,925 shares of Series C 7.0% Cumulative Convertible Perpetual Preferred Stock, or Series C Convertible Preferred Stock, and 12,075 shares of Series A-1 Hybrid Preferred Stock for $150 million. Prior to the private placement, Ares beneficially owned approximately 6.3% of our outstanding common stock. The private placement increased Ares' beneficial ownership to approximately 7.6% (or 12.9% if the shareholders approve the convertibility of the shares of Hybrid Preferred 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 Convertible Preferred Stock, as more fully described in "Item 10. Directors, Executive Officers and Corporate Governance—Preferred Stock Directors."

- Entities affiliated with Oaktree purchased 11,700 shares of Series B 7.0% Cumulative Convertible Perpetual Preferred Stock, or Series B Convertible Preferred Stock, and 48,300 shares of Series A-1 Hybrid Preferred Stock for $600 million. Prior to the private placement, Oaktree beneficially owned approximately 3.1% of our outstanding common stock. The private placement increased Oaktree's beneficial ownership to approximately 8.5% (or 25.6% if the shareholders approve the convertibility of the shares of Hybrid Preferred Stock). Vincent J. Cebula, one of our directors, is a Managing Director of Oaktree. Mr. Cebula was designated to our board of directors by Oaktree pursuant to the terms of the Series B Convertible Preferred Stock, as more fully described in "Item 10. Directors, Executive Officers and Corporate Governance—Preferred Stock Directors."
- Entities affiliated with Greenhill Capital Partners, LLC purchased 1,463 shares of Series A-1 7.0% Cumulative Convertible Perpetual Preferred Stock, or Series A-1 Convertible Preferred Stock, and 6,037 shares of Series A-1 Hybrid Preferred Stock shares for $75 million. Prior to the private placement, Greenhill beneficially owned approximately 2.3% of our outstanding common stock. The private placement increased Greenhill's beneficial ownership to approximately 3.0% (or 5.8% if the shareholders approve the convertibility of the shares of Hybrid Preferred Stock). Robert H. Neihaus, 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% Convertible Preferred Stock and 8,048 shares of Series A-1 Hybrid Preferred Stock shares for $100 million. Prior to the private placement, FMR Corp. beneficially owned approximately 7.0% of our outstanding common stock. The private placement increased FMR Corp.'s beneficial ownership to approximately 7.9% (or 11.4% if the shareholders approve the convertibility of the shares of Hybrid Preferred Stock).

In connection with the private placement, we entered into the following agreements:

Preferred Stock Purchase Agreement

On March 28, 2007, we entered into a Preferred Stock Purchase Agreement, which we refer to as the Stock Purchase Agreement, with the investors in the private placement, pursuant to which we issued and sold to the investors (a) an aggregate of $390 million of shares of our Series A-1 Convertible Preferred Stock, Series A-2 7.0% Cumulative Convertible Perpetual Preferred Stock, or Series A-2 Convertible Preferred Stock, Series B Convertible Preferred Stock and Series C Convertible Preferred Stock and (b) an aggregate of $1.61 billion of shares of our Series A-1 Hybrid Preferred Stock and Series A-2 Hybrid Preferred Stock. The Stock Purchase Agreement included representations, warranties, covenants and indemnities customary for a transaction of this type. We covenanted to seek the approval of our common shareholders of the (i) designations, preferences, limitations and rights set forth in Annex III of the statement of designations of the Hybrid Preferred Stock, including the convertibility of the Hybrid Preferred Stock into our common stock, (ii) the issuance of all of the shares of common stock issuable upon conversion of the Hybrid Preferred Stock, and (iii) removal of the restriction on adjustments of the conversion price of the Convertible Preferred Stock, each in accordance with the rules of the New York Stock Exchange ("NYSE"). We refer to this approval as the NYSE shareholder approval and to all the items to be approved, collectively, as the NYSE approval proposal. We agreed to prepare and distribute proxy materials as promptly as possible to solicit proxies for approval of the NYSE approval proposal and to hold a meeting of shareholders no later than September 26, 2007, to vote upon the NYSE approval proposal. We also granted holders of the Convertible Preferred Stock and Hybrid Preferred Stock a right of first offer with respect to any subsequent issuances of shares by us of common stock (or other securities convertible into or exchangeable for common stock) at a price per share less than the then-effective conversion price of the Convertible Preferred Stock and, after the NYSE shareholder approval, the Hybrid Preferred Stock, subject to customary exceptions.

Registration Rights Agreements

In connection with the Stock Purchase Agreement, on March 28, 2007, we entered into a Registration Rights Agreement with the investors, which we refer to as the 7.0% Registration Rights Agreement, with respect to the registration of the resale of the shares of common stock underlying the Convertible Preferred Stock and the Hybrid Preferred Stock, the shares of Series A-1 Convertible Preferred Stock and, after the NYSE shareholder approval, the shares of Series A-1 Hybrid Preferred Stock that were issued and sold pursuant to the Stock Purchase Agreement. The 7.0% Registration Rights Agreement contains customary terms and conditions for a transaction of this type. We have 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 Convertible Preferred Stock and to use our best efforts to have the registration statement declared effective by March 24, 2008. If any shares of Convertible Preferred Stock are outstanding on March 30, 2011, we have 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, or 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 0.50% per annum of the Convertible Preferred Stock liquidation preference 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 2.00% per annum during any default period. We have also agreed to indemnify holders against certain liabilities under the Securities Act in respect of any such resale registration.

In connection with the Stock Purchase Agreement, on March 28, 2007, we also entered into a Registration Rights Agreement with the investors, which we refer to as the Hybrid Registration Rights Agreement, with respect to the registration of the resale of the shares of Series A-1 Hybrid Preferred Stock that were issued and sold pursuant to the Stock Purchase Agreement. If we have not obtained the NYSE shareholder approval by September 26, 2007, we have agreed to file a registration statement with the SEC by December 24, 2007, covering the resale prior to the NYSE 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 Right Agreement contains liquidated damages payment provisions similar to the 7.0% Registration Rights Agreement and similar indemnification obligations.

Director Nomination Letter Agreements

In connection with the Stock Purchase Agreement, we entered into a letter agreement, dated March 28, 2007, with certain investors affiliated 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 Convertible Preferred Stock and (ii) less than 25% of the shares of Convertible 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 Stock Purchase Agreement, 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 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 Convertible Preferred Stock and (ii) less than 25% of the shares of Convertible 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).

The terms of each class and series of preferred stock issued in the private placement are described below:

Convertible Preferred Stock

Series A-1 Convertible Preferred Stock. The Series A-1 Convertible Preferred Stock is convertible into our common stock at a price of $19 per share, as may be adjusted in accordance with the terms of the Series A-1 Convertible Preferred Stock, and we may force the conversion of the Series A-1 Convertible Preferred Stock at any time if our common stock trades for 20 days within a period of 30 consecutive days at a price above 175% of the then effective conversion price ($33.25 per share at the current conversion price of $19 per share) at any time during the 24 months after issuance, above 150% of the then effective conversion price ($28.50 per share at the current conversion price of $19 per share) thereafter through the 48th month after issuance and above 125% of the then effective conversion price ($23.75 per share at the current conversion price of $19 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% thereafter. In lieu of paying cash dividends, we may, under certain circumstances prior to March 30, 2013, pay a dividend by adding the dividend at a rate of 9.0% per annum to the liquidation preference of the shares of Series A-1 Convertible Preferred Stock. Upon the occurrence of a change of control, holders of the Series A-1 Convertible Preferred Stock may require us to repurchase their shares for cash at the liquidation preference plus accumulated dividends. Holders of the Series A-1 Convertible Preferred Stock have the right to vote with the holders of common stock, the other holders of Convertible Preferred Stock and, after the NYSE Shareholder Approval, the holders of Hybrid Preferred Stock, together as a single class, on all matters submitted to the shareholders of EXCO, except the election of directors and the NYSE approval proposal, on an as-converted basis. Holders of the Series A-1 Convertible Preferred Stock, the Series B Convertible Preferred Stock, the Series C Convertible Preferred Stock and, after the NYSE shareholder approval, the Series A-1 Hybrid Preferred Stock, have the right to separately elect up to four directors, referred to as the "preferred stock directors," subject to the rights of the Series B Convertible Preferred Stock and Series C Convertible Preferred Stock to vote as separate classes to each elect one of such preferred stock directors. In addition, upon the occurrence of specified defaults in the Statements of Designation for the Convertible Preferred Stock and the Hybrid Preferred Stock, the holders of the Convertible Preferred Stock and Hybrid Preferred Stock, voting together as a class, have the right to elect four additional directors, referred to as the "default directors," until such default is cured.

Series A-2 Convertible Preferred Stock. The Series A-2 Convertible Preferred Stock has substantially the same rights as the Series A-1 Convertible Preferred Stock, except that holders of Series A-2 Convertible Preferred Stock do not have the right to elect directors (other than the default directors) and do not have registration rights under the 7.0% Registration Rights Agreement. Shares of Series A-2 Convertible Preferred Stock automatically convert into shares of Series A-1 Convertible Preferred Stock when the holder thereof has provided us with a certificate certifying that either no filing is required under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, or the HSR Act, with respect to such holder's acquisition of the shares of Series A-1 Convertible Preferred Stock or the waiting period applicable to such holder under the HSR Act has expired.

Series B Convertible Preferred Stock. The Series B Convertible Preferred Stock was issued to Oaktree and has substantially the same rights as the Series A-1 Convertible Preferred Stock, except that the holders of Series B Convertible Preferred Stock will 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 Convertible Preferred Stock is convertible into Series A-1 Convertible Preferred Stock at any time at the election of the holder and will automatically convert into Series A-1 Convertible Preferred Stock when Oaktree ceases to own an aggregate of 10,000 shares of Series B Convertible Preferred Stock and/or Hybrid Preferred Stock.

Series C Convertible Preferred Stock. The Series C Convertible Preferred Stock was issued to Ares and has substantially the same rights as the Series A-1 Convertible Preferred Stock, except that the holders of Series C Convertible Preferred Stock will 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 C Convertible Preferred Stock is convertible into Series A-1 Convertible Preferred Stock at any time at the election of the holder and will automatically convert into Series A-1 Convertible Preferred Stock when Ares ceases to own an aggregate of 10,000 shares of Series C Convertible Preferred Stock and/or Hybrid Preferred Stock.

Hybrid Preferred Stock

Initially the Hybrid Preferred Stock is not convertible into common stock. If the NYSE shareholder approval is obtained in accordance with the rules and regulations of the NYSE, then the terms of the Series A-1 Hybrid Preferred Stock and the Series A-2 Hybrid Preferred Stock will transform into the same designations, preferences, limitations and relative voting rights as the Series A-1 Convertible Preferred Stock and the Series A-2 Convertible Preferred Stock, respectively, including the dividend rights and the right to convert into common stock. We have covenanted to seek the NYSE shareholder approval under the Stock Purchase Agreement.

Series A-1 Hybrid Preferred Stock. Prior to the NYSE shareholder approval, dividends will accrue on the Series A-1 Hybrid Preferred Stock at a rate of 11.0% per annum and are payable in cash. If the NYSE shareholder approval has not been obtained by September 26, 2007, the annual dividend rate will increase by 0.50% per quarter (up to a maximum rate of 18% per annum) until the NYSE shareholder approval has been obtained. Prior to the earlier of September 26, 2007 and the date that the NYSE shareholder approval is obtained, the Series A-1 Hybrid Preferred Stock may be redeemed only with the consent of the holders of the Hybrid Preferred Stock at a redemption price equal to 100% of the liquidation preference plus accrued dividends. After September 26, 2007 and prior to NYSE shareholder approval, the Series A-1 Hybrid Preferred Stock is redeemable at our option at any time, and must be redeemed following the maturity of our 7.0% Senior Notes due 2011, for cash at 125% of the liquidation premium plus accrued dividends. Upon the occurrence of a change of control, holders of the Series A-1 Hybrid Preferred Stock may require us to repurchase their shares for cash at 101% of the liquidation preference plus accrued dividends. In addition, upon the occurrence of specified defaults in the Statements of Designation for the Hybrid Preferred Stock, the holders of the Convertible Preferred Stock and Hybrid Preferred Stock, voting together as a class, have the right to elect four default directors until such default is cured. In addition, prior to the NYSE shareholder approval, the Series A-1 Hybrid Preferred Stock contains covenants restricting our incurrence of additional indebtedness and requiring us to repurchase the shares following certain asset dispositions.

Series A-2 Hybrid Preferred Stock. The Series A-2 Hybrid Preferred Stock has substantially the same rights as the Series A-1 Hybrid Preferred Stock, except that holders of Series A-2 Hybrid Preferred Stock do not have the right to elect directors other than the default directors and have no registration rights. Shares of Series A-2 Hybrid Preferred Stock automatically convert into shares of Series A-1 Hybrid Preferred Stock when the holder thereof has provided us with a certificate certifying that either no filing is required under the HSR Act with respect to such holder's acquisition of the shares of Series A-1 Hybrid Preferred Stock or the waiting period applicable to such holder under the HSR Act has expired.

Haynes and Boone, LLP

William L. Boeing, our Vice President, General Counsel and Secretary, was a partner at Haynes and Boone, LLP, which serves as our outside corporate counsel, before he joined us on April 1, 2006. From January 1, 2006 to March 31, 2006, we paid legal fees of approximately $780,000 to Haynes and Boone, LLP. Mr. Boeing's interest in such fees was less than $10,000.

In accordance with our audit committee charter, our audit committee is responsible for reviewing and approving the terms and conditions of all related party transactions. Any material financial transaction with any director, executive officer, nominee or holder of five percent or more of our securities, or immediate family member of any of the foregoing, would need to be approved by our audit committee prior to our entering into such transaction.

The audit committee did not review and approve the sharing of the suite at the American Airlines Center with Boone Pickens, as the sharing of the suite was viewed as a simple expense sharing arrangement where costs and use were split 50/50 between the Company and Mr. Pickens. In addition, while the preferred stock transaction was not approved by the audit committee independently (firms associated with two of the three members of the audit committee participated in the private placement), it was approved by the entire board of directors, including a majority of the disinterested directors, and the relationships with and participation by all related parties was discussed.

Director Independence

The standards relied upon by the Board of Directors in affirmatively determining whether a director is "independent" in compliance with the rules of NYSE are comprised, in part, of those objective standards set forth in NYSE rules. In addition, no director will qualify as "independent" unless the Board affirmatively determines that the director has no material relationship with the EXCO (either directly or as a partner, shareholder or officer of an organization that has a relationship with us). The following commercial or charitable relationships, although not exclusive, will not be considered to be material relationships that would impair a director's independence: (a) the director is an executive officer or owns beneficially or of record more than a ten percent equity interest of another company that does business with us or its subsidiaries and the annual sales to, or purchases from, us or our subsidiaries are less than five percent of the annual revenues of the company he or she serves as an executive officer of; (b) the director is an executive officer or owns beneficially or of record more than a ten percent equity interest of another company which is indebted to us or our subsidiaries, or to which we or our subsidiaries is indebted, and the total amount of either company's indebtedness to the other is less than five percent of the total consolidated assets of the company he or she serves as an executive officer of; and (c) the director serves as an officer, director or trustee of a charitable organization, and our discretionary charitable contributions to the organization are less than five percent of that organization's total annual charitable receipts. Any automatic matching by us of employee charitable contributions will not be included in the amount of our contributions for this purpose.

The Board of Directors, in applying the above-referenced standards, has affirmatively determined that our current "independent" directors are: Jeffrey D. Benjamin, Vincent D. Cebula, Earl E. Ellis, Robert H. Niehaus, Jeffrey S. Serota and Robert L. Stillwell. As part of the Board's process in making such determination, each such director provided written assurances that (a) all of the above-cited objective criteria for independence are satisfied and (b) he has no other "material relationship" with us that could interfere with his ability to exercise independent judgment.

In addition to the transactions, relationships and arrangements described under the heading "—Transactions with Related Persons," in determining that the directors above are "independent," the Board considered the relationships described below.

Robert L. Stillwell's son worked for us from 2002-2005. In 2005, Mr. Stillwell's son received a payment of over $60,000 for stock options he held of EXCO Holdings. This does not disqualify Mr. Stillwell from being deemed independent for NYSE purposes under the objective criteria. However, for 2006, this relationship disqualified him from being a "non-employee" director under Rule 16b-3. He is not disqualified from being a "non-employee" director in 2007. In addition, Mr. Stillwell is not independent for purposes of serving on our audit committee under Rule 10A-3(a)(3) because he is employed by BP Capital

LP, an entity owned by Mr. Boone Pickens. BP Capital LP is likely an affiliate of us by virtue of the two entities being under common control. The Board has determined that none of the above relationships interfere with Mr. Stillwell's ability to exercise independent judgment.

Jeffrey D. Benjamin holds a working interest in certain wells managed by Woolsey Petroleum in which we also hold a working interest. We do not operate these wells, and we and Mr. Benjamin are not parties to a common agreement. Furthermore, Mr. Benjamin's annual distributions from such wells during each of the last three fiscal years is not a material amount. Additionally, Mr. Benjamin in a non-employee, senior advisor to Apollo Management, LP, or Apollo. An entity affiliated with Apollo, Apollo Investment Corporation, purchased 975 shares of Series A-1 7.0% Preferred Stock and 4,025 shares of Series A-1 Hybrid Preferred Stock shares for $50 million in the private placement described under "—Transactions with Related Persons—Private placement of preferred stock." These interests do not disqualify Mr. Benjamin from being deemed independent for NYSE purposes under the objective criteria and the Board of Directors has determined that these interests do not interfere with his ability to exercise independent judgment.

Earl E. Ellis serves as an executive officer and is a significant stockholder of company of which Messrs. Miller and Smith were directors until November 2, 2005. We sought guidance from the NYSE regarding a potential disqualification from independence based upon these relationships. Given that Mr. Ellis received no compensation for his service as an executive officer and that Messrs. Miller and Smith were not on the compensation committee of the private company, we were told that Mr. Ellis could be deemed to be independent for NYSE purposes. Effective November 2, 2005, Messrs. Miller and Smith resigned from the board of the private company to avoid any possible future conflicts. Messrs. Miller and Smith also own equity interests in this same company, but their interests represent less than 5% of the total equity ownership. The Board determined that these relationships do not interfere with Mr. Ellis's ability to exercise his independent judgment.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Aggregate fees for professional services provided to us by KPMG LLP, or KPMG, and PricewaterhouseCoopers LLP, or PWC, for the years ended December 31, 2005 and 2006 were as follows:

		2006		
	2005	PWC	KPMG	Total
		(in thousands)		
Audit Fees(a)	$1,692	$1,514	$1,446	$2,960
Audit-Related Fees(b)	3	400	1,717	2,117
Tax Fees(c)	—	10	108	118
All Other Fees	—	1	—	1
Total	$1,695	$1,925	$3,271	$5,196

(a) Fees for audit services include fees associated with the annual audit, the reviews of EXCO's quarterly reports on Form 10-Q and our Form S-1 registration statement filed with the SEC in connection with our initial public offering that was completed on February 14, 2006.

(b) Audit-related fees principally included accounting consultations and fees incurred related to our 2006 acquisitions, our Form S-1 registration statement filed with the SEC in connection with the resale of shares of our common stock acquired in the Equity Buyout and Sarbanes-Oxley compliance testwork. Excludes fees incurred in 2006 for services provided by PWC after PWC was dismissed as our principal accountant.

(c) Tax fees, when incurred, include tax compliance and tax planning.

In considering the nature of the services provided by KPMG and PWC, the audit committee determined that such services are compatible with the provision of independent audit services. The audit committee discussed these services with KPMG and PWC and our management to determine that they are permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants.

Pre-Approval of Independent Registered Public Accounting Firm Fees and Services Policy

The audit committee has adopted a policy that requires advance approval of all audit services and non-audit services performed by the independent registered public accounting firm or other public accounting firms. Audit services approved by the audit committee within the scope of the engagement of the independent registered public accounting firm are deemed to have been pre-approved. The policy further provides that pre-approval of non-audit services by the independent registered public accounting firm will not be required if:

- the aggregate amount of all such non-audit services provided by the independent registered public accounting firm to us does not constitute more than 5% of the total amount of revenues paid by us to the independent auditor during that fiscal year;
- such non-audit services were not recognized by us at the time of the independent registered public accounting firm's engagement to be non-audit services; and
- such non-audit services are promptly brought to the attention of the audit committee and approved by the audit committee prior to the completion of the audit.

The audit committee may delegate to one or more members of the audit committee the authority to grant pre-approval of non-audit services provided that such member or members reports any decision to the audit committee at its next scheduled meeting.

The audit committee pre-approved all of the aggregate audit fees, audit-related fees, tax fees and other fees set forth in the table.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(3) Exhibits

EXHIBIT NUMBER	Description Of Exhibit
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Executive Officer of EXCO Resources, Inc., filed herewith.
31.2	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Financial Officer of EXCO Resources, Inc., filed herewith.
31.3	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Chief Accounting Officer of EXCO Resources, Inc., filed herewith.

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 amendment no. 1 to its annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

EXCO RESOURCES, INC.
(Registrant)

Date: April 16, 2007

By: /s/ DOUGLAS H. MILLER
Douglas H. Miller
Chairman and Chief Executive Officer

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
Oaktree Capital Management, L.P.

Earl E. Ellis [1,2,3]
Chairman and Chief Executive Officer
Whole Harvest Products

Robert H. Niehaus [1,2,3]
Chairman and Managing Partner
Greenhill Capital Partners, LLC

Boone Pickens
Chairman and Chief Executive Officer
BP Capital LP

Jeffrey S. Serota [2,3]
Managing Director
Ares Management, LLC

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 and
Assistant Secretary

Mark E. Wilson
Vice President, Controller and
Chief Accounting Officer

Michael R. Chambers, Sr.
Vice President of Operations

W. Justin Clarke
Assistant General Counsel,
Chief Compliance Officer
and Assistant Secretary

Charles R. Evans
Vice President-
EXCO Mid-Continent

John D. Jacobi
Vice President-
Business Development

Daniel A. Johnson
Vice President-
East Texas Operations

Stephen E. Puckett
Vice President-
Reservoir Engineering

Paul B. Rudnicki
Vice President-Financial
Planning and Analysis

[1]Audit Committee Member [2]Compensation Committee Member [3]Nominating and Corporate Governance Committee Member

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

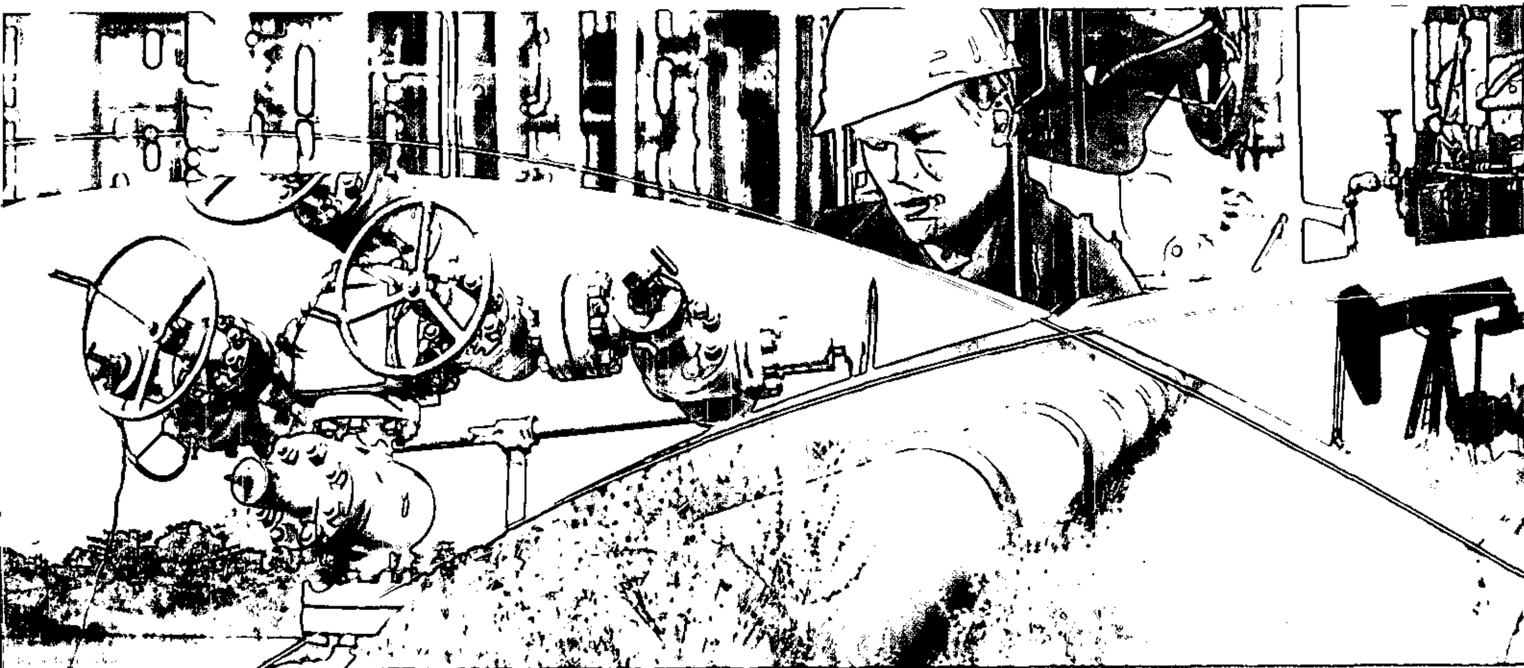
Vinson & Elkins LLP
Trammell Crow Center
2001 Ross Avenue, Suite 3700
Dallas, TX 75201

Number of Common Shareholders

6,839
(As of July 13, 2007)

Stock Transfer Agent

Continental Stock Transfer
& Trust Company
Communications concerning
transfer or exchange
requirements, lost certificates,
share holdings 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

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