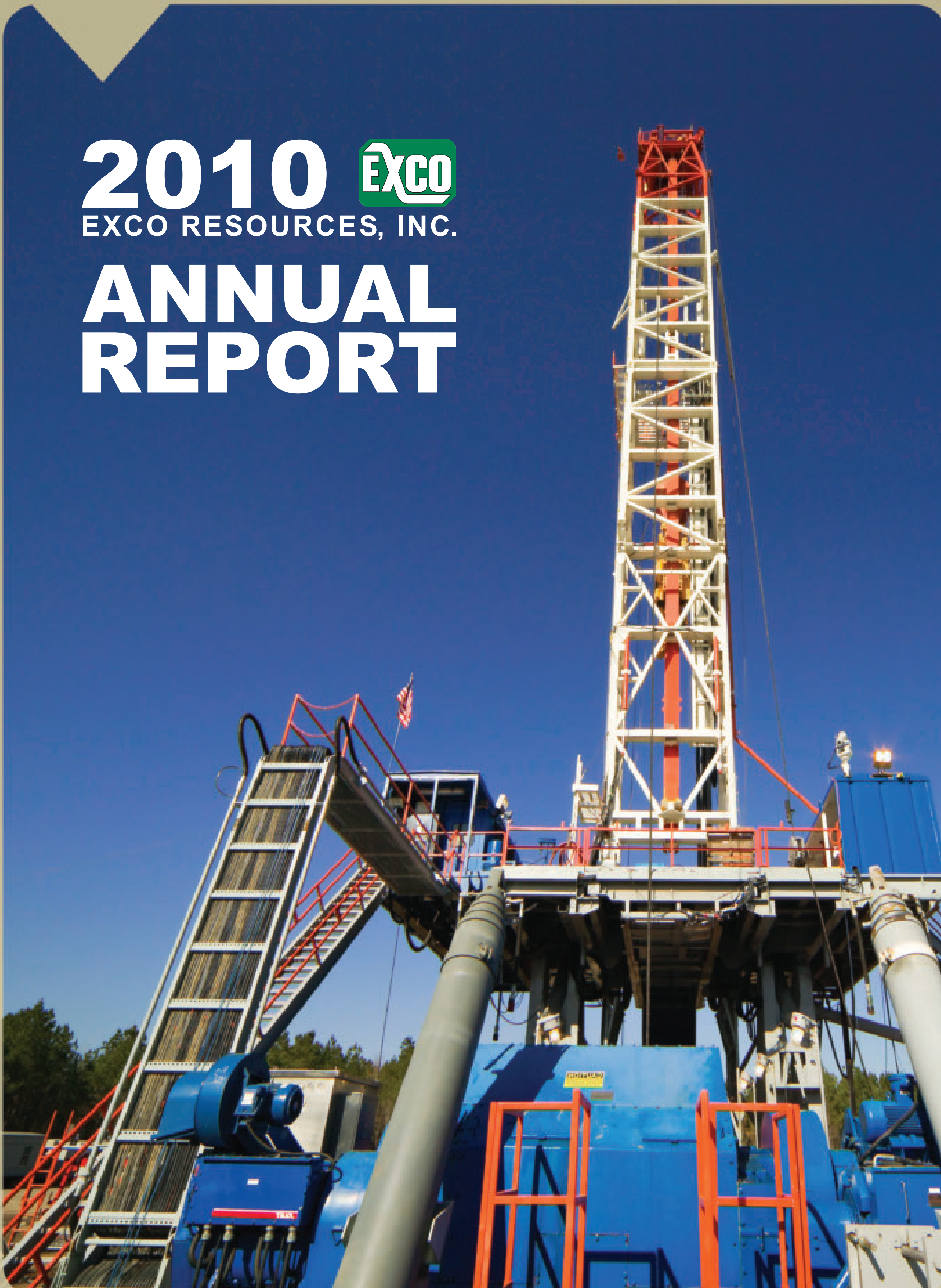
2010
EXCO RESOURCES, INC.
ANNUAL REPORT



Mission Statement

EXCO Resources, Inc. is a natural gas and oil company engaged in the exploration, exploitation, development and production of onshore natural gas and oil properties. Our operations are focused in certain key natural gas and oil producing regions of the United States.

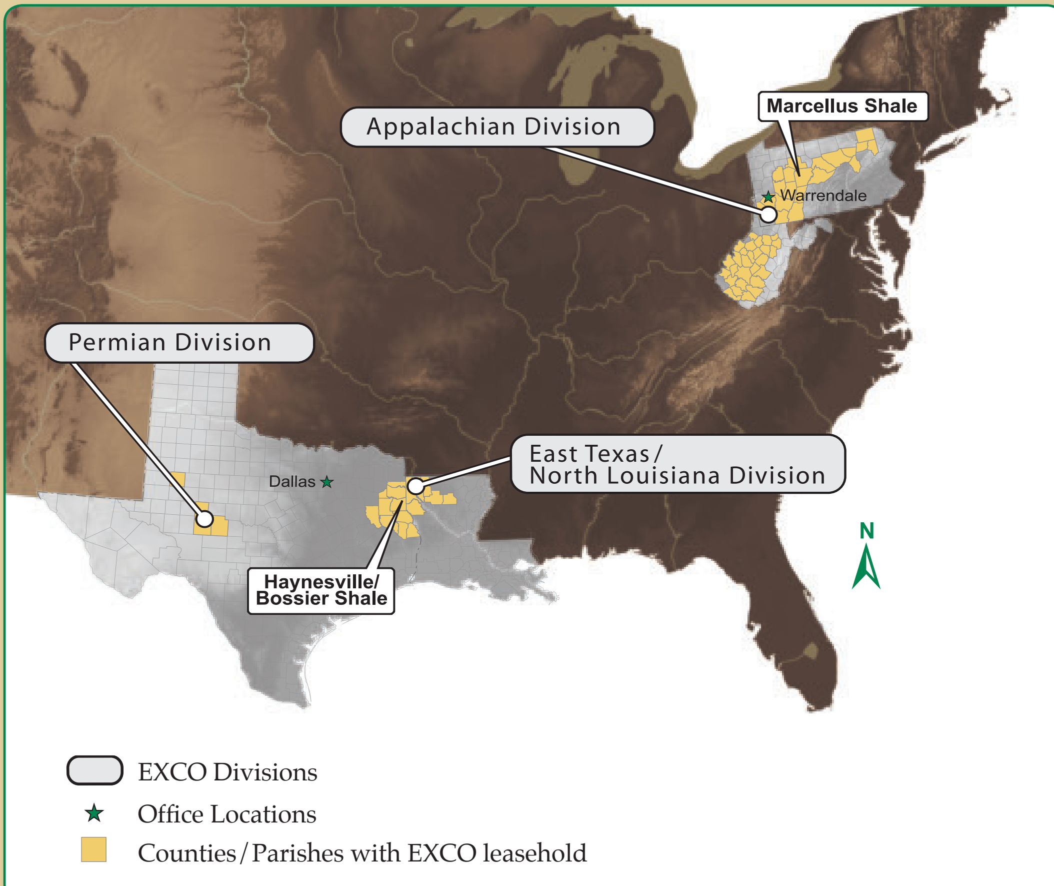
Our primary goal is to build value for our shareholders by enhancing the value of our assets through efficient operations, a high technology drilling program, development of our properties and exploitation of unproved upside.

Guiding Principles

At EXCO we achieve our mission within the framework established by our guiding principles.

Ethics:	We are committed to transparency and conducting our business ethically and lawfully. We are accountable by taking responsibility for our actions and results.
Safety:	We provide a safe place to work and protect our environment.
Teamwork:	We create a work environment that encourages teamwork and cooperation by treating each other with respect and understanding.
Technology:	We pursue continuous improvement by encouraging technological innovation in the achievement of our goals.
Growth:	We work to produce a high return and deliver on commitments to our shareholders.

Operating Areas



Haynesville / Bossier Shale:

- 100% drilling success rate
- Significant production growth
- Existing infrastructure and access to multiple markets
- Readily available field services

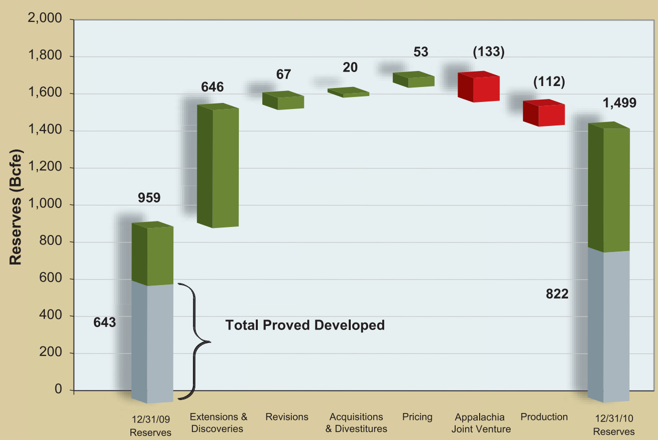
Marcellus Shale:

- Massive resource potential
- Great proximity to Northeast markets
- Developing infrastructure and field services

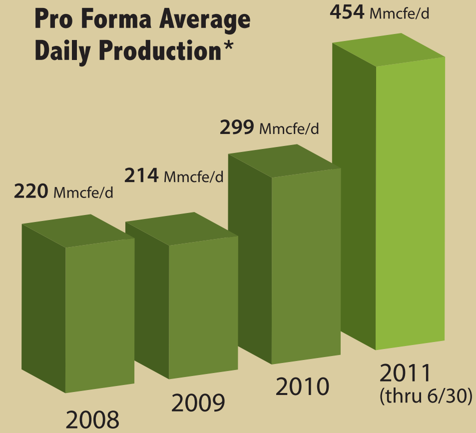
Company Highlights

Following asset acquisitions, sales and joint ventures in 2008-2010, we have effectively increased reserves, grown production, and managed our balance sheet.

2009-2010 Proved Reserves

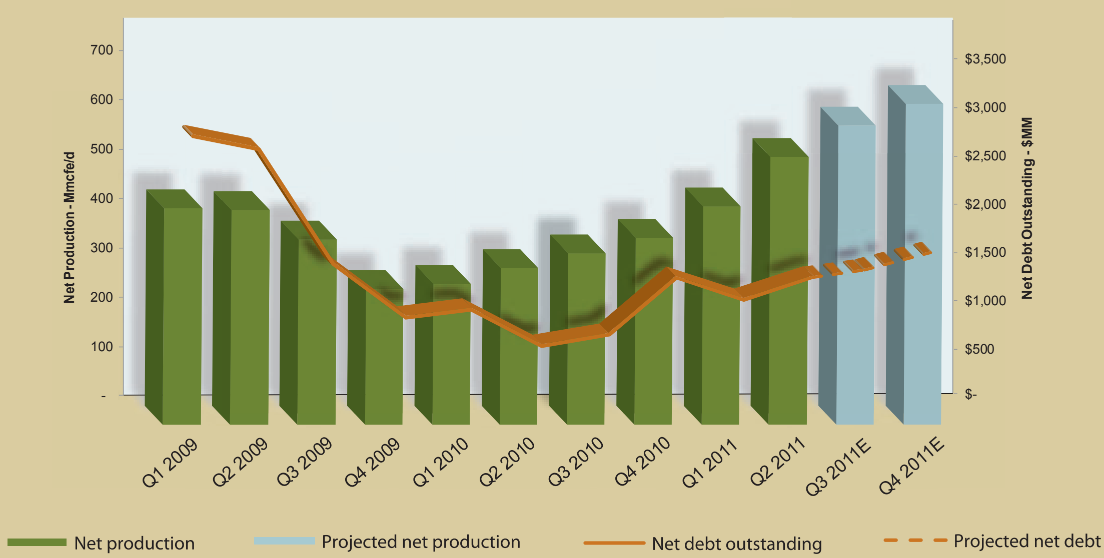


Pro Forma Average Daily Production*



*Historical production volumes adjusted as if 2008 acquisitions and 2009 and 2010 divestitures and joint ventures occured on January 1, 2008.

Production and Debt Profile



Dear Fellow Shareholders:

On behalf of our entire management team, we are pleased to report that EXCO had a very successful 2010, and we have carried that momentum into 2011. Our continued focus on our core shale assets and the contributions of our dedicated employees have resulted in our successful development program. At year-end 2010, we had proved reserves of approximately 1.5 Tcfe, 97% of which were natural gas and 55% of which were proved developed reserves with a reserve life of 13.4 years. Our production increased to a 2010 exit rate of approximately 385 Mmcfe per day, and we expect to reach 600 Mmcfe per day by the end of 2011. We are proud of our accomplishments and our ability to successfully execute our strategy while navigating through the challenging natural gas price environment. Our high quality assets and hedging program allow us to maintain financial flexibility and follow our strategy with a disciplined, long-term view.

Our approach to the profitable growth of EXCO is based on five factors:

- Finding quality assets with a shale focus;
- Maintaining an appropriate capital structure supported by a strong balance sheet;
- Engaging people with world-class technical and commercial expertise;
- Developing business and technical processes to ensure appropriate governance and application of technology; and
- Emphasizing continuous improvement.

In 2010 we saw the continued success with our shale drilling and operations. In our core DeSoto Parish area, we are now in full manufacturing mode and in the Shelby Trough, our second Haynesville/Bossier shale core area, our results are very encouraging as we have seen record production volumes in both our Haynesville and Bossier shale plays. Our operating and technical personnel continue to refine the drilling and completion processes, where we have reduced our spud to completion time significantly on our Haynesville wells. As we transform our Haynesville/Bossier shale plays from appraisal to manufacturing phases, we have also begun a development program in northeast Pennsylvania and are appraising several areas in central and western Pennsylvania. Our knowledge base regarding every aspect of drilling, completing and operating shale wells is expanding dramatically. It has allowed us to maintain an aggressive development schedule that meets our economic hurdle rates and is yielding a high degree of success. We currently have more than 9,300 identified shale drilling locations with over 75,000 net acres in the Haynesville shale play and 140,000 net acres in the Marcellus shale play. A significant competitive advantage we have is that a majority of our leases are held by production. Our joint ventures with BG Group continue to thrive, providing us the ability to accelerate development of our drilling locations and acreage in our Haynesville/Bossier and Marcellus shale plays.

We continue to expand our gathering and pipeline systems both in East Texas/North Louisiana and Appalachia to match our development program and allow for timely and efficient well hook-ups and market access for our production. Our integrated midstream operations in the East Texas and North Louisiana area allow us to connect our Haynesville and Bossier wells immediately, maximizing returns on our investment. Our midstream joint venture manages assets including over 1,000 miles of pipeline. Our Louisiana and Texas pipelines had throughput of over 1.5 Bcf per day in early July 2011, and we anticipate that this throughput could approach 2.0 Bcf per day by the end of 2011.

Safety is paramount at EXCO, and we continually strive to be an industry leader in safety performance. We implemented a security and remote well monitoring system which allows us to establish automated alerts by measuring numerous parameters in, on and around our wells. Our control room is staffed 24 hours a day, 7 days a week to assist with monitoring and managing our field operations.

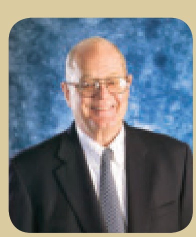
To maintain our financial flexibility, we issued $750 million of 7.5% senior notes due in 2018 in September 2010. The net proceeds were used to repay our existing $450 million of notes and the remainder was used to reduce our bank borrowings. We recently expanded our borrowing base from $1.0 billion to $1.5 billion reflecting our successful development programs, the resulting increase in our reserves and the confidence our bank group has in EXCO. The additional borrowing capacity will allow EXCO to take advantage of strategic acquisitions and drilling opportunities.

Our employee base has expanded to include numerous technical experts, innovation and optimization specialists, geotechnical teams and support staff. We continue to hire outstanding team members, and we provide numerous professional development programs to enhance the skills and knowledge of our employees. As of June 30, 2011, EXCO had over 1,000 employees. EXCO is a preferred employer through a comprehensive and competitive benefits package, energized work environment and employee development opportunities. This focus on our employees resulted in EXCO being named a top 100 place to work in Dallas in a 2010 Dallas Morning News survey.

On behalf of everyone at EXCO, we would like to thank you for your continued support.

Sincerely,

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



Stephen F. Smith
Vice Chairman of the
Board, President and
Chief Financial Officer

EXCO's Field Operations Control Center

EXCO's Geosteering Control Center

Forward-looking Statements and SEC and NYSE Certifications

We believe that it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. You are cautioned not to place undue reliance on a forward-looking statement. When considering our forward-looking statements, keep in mind the risk factors and other cautionary statements included in our Annual Report on Forms 10-K and 10-K/A for the year ended December 31, 2010, and our other periodic filings with the Securities and Exchange Commission (SEC).

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

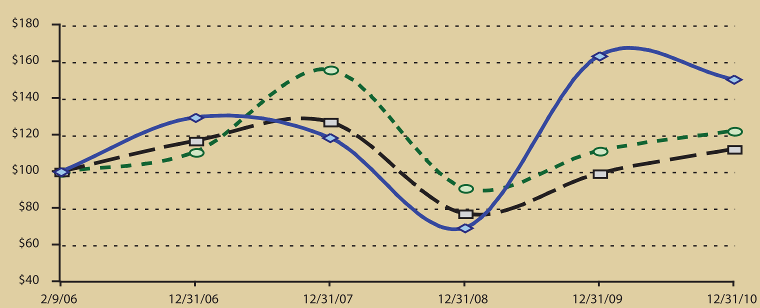
SEC and NYSE Certifications

The Forms 10-K and 10-K/A, included herein, which were filed by the company with the SEC for the fiscal year ending December 31, 2010, include, as exhibits, the certifications of our chief executive officer and chief financial officer required to be filed with the SEC. Our chief executive officer also filed his 2010 annual CEO certification with the NYSE confirming that the company has complied with the NYSE corporate governance listing standards.

EXCO's Common Stock Performance

The graph to the right compares the cumulative total return (what $100 invested on February 9, 2006, the date of our IPO, would be worth on December 31, 2010) on the company's common stock with the cumulative total return on the NYSE Composite Index and the Crude Petroleum and Natural Gas SIC Code Index.

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



	Period Ending					
	2/9/06	12/31/06	12/31/07	12/31/08	12/31/09	12/31/10
EXCO Resources, Inc.	$ 100.00	$ 129.58	$ 118.62	$ 69.43	$ 163.13	$ 150.47
NYSE Composite Index	$ 100.00	$ 116.85	$ 127.21	$ 77.27	$ 99.13	$ 112.40
Crude Petroleum and Natural Gas Index	$ 100.00	$ 110.79	$ 155.74	$ 91.13	$ 111.51	$ 122.37

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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2010

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	**74-1492779**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
12377 Merit Drive, Suite 1700, LB 82 **Dallas, Texas**	**75251**
(Address of principal executive offices)	(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
Rights to Purchase Series A Junior Participating Preferred Stock	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 has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant is required to submit and post such files). YES ☒ NO ☐

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

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

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

As of February 17, 2011, the registrant had 213,575,593 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 the registrant's common stock held by non-affiliates was $2,158,830,000.

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

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement to be furnished to shareholders in connection with its 2011 Annual Meeting of Shareholders are incorporated by reference in Part III, Items 10-14 of this Annual Report on Form 10-K.

TABLE OF CONTENTS

EXCO RESOURCES, INC.

PART I

ITEM 1. BUSINESS

General

Unless the context requires otherwise, references in this Annual Report on Form 10-K to "EXCO," "EXCO Resources," "Company," "we," "us," and "our" are to EXCO Resources, Inc. and its consolidated subsidiaries.

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 31.

We are an independent oil and natural gas company engaged in the exploration, exploitation, development and production of onshore North American oil and natural gas properties with a focus on shale resource plays. Our principal operations are conducted in key North American oil and natural gas areas including East Texas, North Louisiana, Appalachia and the Permian Basin in West Texas. In addition to our oil and natural gas producing operations, we own 50% interests in two midstream joint ventures located in East Texas/North Louisiana and Appalachia, respectively. As of December 31, 2010, our Proved Reserves were approximately 1.5 Tcfe, of which 97.1% were natural gas and 54.8% were Proved Developed Reserves. As of December 31, 2010, the related PV-10 of our Proved Reserves was approximately $1.4 billion, and the Standardized Measure of our Proved Reserves was $1.2 billion (see "—Summary of geographic areas of operations" for a reconciliation of PV-10 to Standardized Measure of Proved Reserves). For the year ended December 31, 2010, we produced 112.0 Bcfe of oil and natural gas resulting in a Reserve Life of approximately 13.4 years.

On October 29, 2010, our Chairman and Chief Executive Officer, Douglas H. Miller presented a letter to our board of directors indicating an interest in acquiring all of the outstanding shares of our stock not already owned by Mr. Miller for a cash purchase price of $20.50 per share. The proposal does not represent a definitive offer and there is no assurance that a definitive offer will be made or accepted, that any agreement will be executed or that any transaction will be consummated.

Our board of directors established a special committee on November 4, 2010 comprised of two of our independent directors to, among other things, evaluate and determine the Company's response to the October 29, 2010 proposal. The special committee retained Kirkland & Ellis LLP and Jones Day as its counsel and Barclays Capital, Inc. and Evercore Partners as its financial advisors to assist it in, among other things, evaluating and determining the Company's response to the proposal. See "Note 19. Acquisition Proposal" of the notes to our consolidated financial statements for further information regarding the proposal.

Our business strategy

Prior to 2009, we used acquisitions of producing properties with vertical development drilling and workover opportunities in established producing areas as our primary vehicle for growth. As a result of those acquisitions, we accumulated an inventory of drilling locations and acreage holdings with significant potential in the Haynesville/Bossier and Marcellus shale resource plays. During 2008, we shifted our focus to exploit these shales primarily through horizontal drilling. Currently, our acquisition strategy is focused on increasing our shale resource holdings in the East Texas/North Louisiana and Appalachian areas. We continue to develop our conventional Permian assets and certain vertical drilling opportunities in East Texas, North Louisiana and Appalachia as economic conditions permit. Our 2011 development strategy is focused on the Haynesville/Bossier shale area in East Texas/North Louisiana and we have increased our activities in the Marcellus shale, principally in Pennsylvania.

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

- ***Develop our shale resource plays***

  We hold significant acreage positions in two prominent shale plays in the United States. In East Texas and North Louisiana, we currently hold approximately 76,000 net acres in the Haynesville/Bossier shales and in Appalachia we currently hold approximately 140,000 net acres in the Marcellus shale. Our Haynesville operations began in 2008 when we commenced with technical evaluations and drilling of test wells. In 2008, we drilled and completed our first horizontal well in the play. Since we commenced our horizontal drilling program in the Haynesville shale, we have spud 164 operated horizontal wells through December 31, 2010, entered into a joint venture with affiliates of BG Group plc, or BG Group, and in 2010, jointly acquired with BG Group approximately 48,000 net acres (24,000 net to EXCO) in Shelby, Nacogdoches and San Augustine Counties in East Texas, or the Shelby Area. We own working interests in 77 Haynesville horizontal wells operated by others. We continue to work closely with our midstream operations to coordinate drilling and completion timing of our wells, which allows us to flow new completions to sales promptly after fracture stimulation.

  In our Appalachia region, we entered into another joint venture with BG Group in June 2010 covering our holdings in the Appalachia basin, including the Marcellus shale resource play. We plan to use a similar process in Marcellus development that was used in the Haynesville shale, with principal activities focused on technical evaluations of our acreage holdings, expansion of our technical staff, evaluation of test wells and a disciplined appraisal drilling program. Our significant held-by-production position allows us to dictate our pace of development in the Marcellus shale. We have commenced a horizontal drilling program with an objective to appraise our existing fields by mid 2011. During 2011, we plan to operate an average of four horizontal drilling rigs in the Marcellus shale. We are currently using two of the rigs to continue appraisal of our acreage and we plan to use two additional rigs to begin development in west central and Northeast Pennsylvania.

- ***Leverage our joint ventures***

  The shale resource plays are capital intensive and require significant expenditures for drilling, completing, treating and pipeline take-away capacity. We have entered into joint venture transactions with BG Group in our shale resource areas. These joint ventures allow us to accelerate development and appraisal programs in our upstream business. Because our midstream joint ventures are also with BG Group, our upstream and midstream objectives are aligned.

- ***Expand our midstream assets***

  We jointly own midstream companies in our East Texas/North Louisiana and Appalachia operating areas with BG Group. These assets enhance our ability to promptly hook-up our wells for delivery of our production to markets. We completed construction of a 36-inch diameter 27-mile header system in DeSoto Parish, Louisiana in 2010 and are completing construction of facilities in the Shelby Area. In Appalachia, we intend to pursue similar midstream expansions as part of our operating strategy. In addition to ensuring delivery of our production, these expansions provide opportunities to gather third party gas and generate incremental gathering and transportation fee income.

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

  Our prior strategy of acquiring producing properties created a portfolio with a multi-year inventory of shale and conventional drilling locations and exploitation projects. This inventory consists of infill drilling, exploratory drilling, workovers and recompletions. In 2010, we drilled and completed 205 wells with a 99.0% drilling success rate. Our natural gas vertical drilling program remains suspended due to low commodity prices, except in our Permian region as these wells contain high oil and natural gas liquids content. As of December 31, 2010, we have identified 11,933 drilling locations and 1,107 exploitation projects across our portfolio.

- ***Maintain financial flexibility***

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

  On September 15, 2010, we closed an underwritten offering of $750.0 million aggregate principal amount of 7.5% Senior Notes due 2018, or the 2018 Notes. We received proceeds of approximately $724.1 million from the offering, after deducting an original issue discount of $11.0 million and commissions, offering fees and expenses of $14.9 million. We used a portion of the net proceeds from the offering to redeem all of our outstanding 71/4% Senior Notes due 2011 for $444.7 million, or the 2011 Notes, in accordance with the terms of the indenture under which those notes were issued.

  We added derivative financial instruments to our portfolio in 2011 and plan to add to the portfolio as opportunities arise.

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

  We periodically review our properties to identify cost savings opportunities and divestiture candidates. We actively seek to dispose of properties with higher operating costs, properties that are not within our core geographic operating areas and properties that are not strategic. We also seek to opportunistically divest properties in areas in which acquisitions and investment economics no longer meet our objectives. We completed a significant divestiture program in 2009 when we divested significant non-core conventional assets in East Texas and substantially all of our holdings in the state of Ohio and the Mid-Continent region.

- ***Seek acquisitions that meet our strategic and financial objectives in our core operating areas***

  Our shale resource plays have created a shift in our acquisition focus from producing properties to opportunistic acreage acquisitions with additional shale potential. Acreage acquisitions differ from our prior strategy of acquiring producing properties as the acreage does not result in immediate production and cash flows or provide an incremental borrowing base increase under our credit agreement. As a result, our acreage acquisition strategy will be dependent on our available borrowing base. Acreage acquisitions within the areas covered by our joint ventures with BG Group are offered to BG Group and provide an additional source of funds to pay for these acquisitions.

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

  Our acquisitions and their resulting shale upside have led to significant reserve addition opportunities above those identified at the date of acquisition. In our East Texas/North Louisiana area, we plan to aggressively drill horizontal wells, implement down spacing of wells, and recomplete existing wells to enhance our production and reserve position. In Appalachia, our focus will be directed toward appraisal drilling programs in several areas and development drilling in west central and Northeast Pennsylvania. We continue to exploit our Permian assets, which have resulted in higher oil production than originally expected.

Our strengths

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

- ***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 and Permian areas. Our properties are generally characterized by:

  - long reserve lives;
  - exploration opportunities;

- a multi-year inventory of development drilling and exploitation projects;
- high drilling success rates;
- a high natural gas concentration; and
- significant unproved reserves and resources.

- ***Joint ventures with BG Group***

  Our joint ventures with BG Group in our shale plays allow us to share the development risk and costs of these capital intensive projects with a large, investment grade partner. We have received $1.8 billion of net proceeds from BG Group from the formation of four separate joint ventures. In addition, BG Group agreed to fund an aggregate of $550.0 million of our share of deep drilling costs in our Haynesville/Bossier and Marcellus shale resource plays. The funds received from our joint venture partner allow us to accelerate development of the shale plays, while affording us the opportunity to evaluate and fund additional shale acreage acquisitions in our focus areas.

  A brief description of each of our joint ventures with BG Group follows:

  - On August 14, 2009, we entered into a joint venture with BG Group covering an undivided 50% interest in our identified assets in the East Texas/North Louisiana area, including the Haynesville/Bossier shale, or the East Texas/North Louisiana JV. The East Texas/North Louisiana JV is governed by a joint development agreement. Our subsidiary, EXCO Operating Company, serves as operator of the East Texas/North Louisiana JV. In addition to a cash purchase price of $713.8 million, our drilling costs in the East Texas/North Louisiana JV benefited from a $400.0 million carry for drilling costs, or the East Texas/North Louisiana Carry, during 2009 and 2010. As of December 31, 2010, we estimate that $30.2 million of the East Texas/North Louisiana Carry was unused.
  - On August 14, 2009, we closed the sale to BG Group of a 50% interest in a newly formed company, TGGT Holdings, LLC, or TGGT, which now holds most of our East Texas/North Louisiana midstream assets.
  - On June 1, 2010, we entered into another upstream joint venture with BG Group in the Appalachia region, or the Appalachia JV. EXCO and BG Group jointly operate the Appalachia JV operations through a 50/50 owned operating entity, EXCO Resources (PA), LLC, or OPCO, which holds a 0.5% working interest in all of the shallow conventional assets and deep rights in Appalachia, including the Marcellus shale. The remaining 99.5% of these assets are owned equally by us and BG Group. In addition to estimated net cash proceeds of $790.2 million, subject to final adjustments in 2011, the Appalachia JV also provides us with a $150.0 million carry on drilling costs, or the Appalachia Carry. As of December 31, 2010, we estimate that $126.8 million of the Appalachia Carry is unused, after estimated final post-closing adjustments.
  - On June 1, 2010, we formed a jointly-owned midstream company, or the Appalachia Midstream JV, to provide take-away capacity in the Marcellus shale.

- ***Skilled technical personnel with supplemental support and expertise from our joint venture partner***

  Over the past three years, we have hired skilled, multi-disciplined technical and operational personnel who have allowed us to increase our horizontal drilling program. In addition, our access to BG Group's personnel in our shale joint ventures complements our execution strategy.

- ***Shale resource plays***

  Our Haynesville, Bossier and Marcellus shale resource plays present significant opportunities to grow our reserves with low finding and development costs. Because a significant portion of the acreage in these areas is held-by-production we have the flexibility to concentrate our drilling activities in higher return areas rather than having our drilling program dictated by the location of expiring leases.

- ***Operational control***

  We operate a significant portion of our properties, coupled with significant held-by-production acreage, 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, 2010, we operated 7,276 of our 7,730 gross wells, or wells representing approximately 96.8% of our Proved Developed Reserves.

- ***Experienced management team***

  Our management team has led both public and private oil and natural gas companies and has an average of over 27 years of industry experience in exploring, acquiring, developing and exploiting oil and natural gas properties. Since acquiring a controlling interest in us in December 1997, the management team has increased our Proved Reserves from approximately 4.7 Bcfe in the beginning of 1998 to approximately 1.5 Tcfe in December 2010.

Plans for 2011

Our 2011 strategy focuses in three areas. Our Haynesville and Bossier shale plans are characterized by development activities based on our past performance coupled with the maturity of our midstream infrastructure. In the Marcellus shale, our emphasis is centered on increasing the technical understanding of the play and conducting development and appraisal drilling programs. As we gain a more robust understanding of the Marcellus shale play, our midstream strategy will become more clearly defined. The Permian Basin region provides superior returns driven by crude oil and high natural gas liquids content. As a result, we plan to continue our two rig Permian drilling program throughout 2011.

Our business strategy in 2011 also includes significant flexibility due to the high concentration of natural gas associated with our shale plays. At current natural gas price levels of $4.00-$5.00 per Mcf, we plan to balance our drilling programs with selective acquisitions. In a low natural gas price environment, which we presently define as under $4.00 per Mcf, we have flexibility to reduce our drilling program beginning in the third quarter of 2011, as term drilling contracts begin to expire, and shift our focus to acquisition opportunities. In an increasing natural gas price environment, we can accelerate drilling. We expect commodity prices, particularly for natural gas, to remain volatile in 2011 and this volatility may have an impact on our drilling activities. We have consistently used derivative financial instruments as a strategy to mitigate commodity price volatility and we expect to continue to enter into derivative financial instruments as opportunities arise.

Budgeted capital expenditures for 2011 total $976.2 million, of which $781.8 million, or 80.0%, are allocated to our East Texas/North Louisiana area and $82.8 million, or 8.5%, are allocated to our Appalachia region. In East Texas and North Louisiana, capital expenditures in the East Texas/North Louisiana JV are expected to total $757.0 million compared with 2010 capital expenditures of approximately $224.3 million. The increase between 2011 expected capital expenditures and 2010 reflects the expiration of the East Texas/North Louisiana Carry on drilling costs within the East Texas/North Louisiana JV. We expect the Appalachia Carry will be utilized in 2011. The impact of the Appalachia Carry is reflected in the $82.8 million 2011 capital budget in Appalachia.

We anticipate that the 2011 capital expenditures for TGGT will be funded with internally generated cash flow and borrowings under a new $500.0 million credit facility, of which an affiliate of BG Group is a 50% lender, or the TGGT Credit Agreement, which closed on January 31, 2011. This credit facility will be used to fund TGGT's continued expansion program. Accordingly, our 2011 capital budget does not contemplate capital contributions to TGGT.

During the fourth quarter of 2010, we entered into two transactions that we expect will significantly expand our presence in the Appalachia region. On December 15, 2010, we funded an escrow account to purchase certain oil and natural gas assets in the Marcellus shale from Chief Oil & Gas LLC, or the Chief Transaction, for approximately $459.4 million, subject to receipt of consents from a third party, post-closing adjustments and completion of title diligence. At the time of acquisition, the acquired properties were producing a net of approximately 16 Mmcf per day from 15 wells and 11 wells were awaiting completion. The Chief Transaction includes approximately 56,000 net acres prospective for the Marcellus shale development. On January 11, 2011, the necessary consents from the third party were received and escrow funds were released. On February 7, 2011, BG Group funded $229.7 million to acquire their 50% share of the Chief Transaction. In addition, we entered into a purchase and sale agreement to purchase additional Marcellus shale prospective acreage and shallow wells that hold the Marcellus deep rights from a private producer for $95.0 million, subject to further due diligence and post-closing adjustments. We anticipate that BG Group will participate in 50% of this acquisition.

Our midstream operations complement our upstream development plans. In 2010, TGGT completed construction of a 36-inch header system and treating facility to facilitate timely delivery of produced volumes from our Haynesville operations in DeSoto Parish, Louisiana. In the fourth quarter of 2010 and into 2011, TGGT's efforts have been dedicated to construction of facilities in our second core Haynesville area located in the Shelby area in East Texas. Appalachia Midstream is presently evaluating alternatives for gathering and treating of Marcellus volumes.

Significant activities during 2010

Haynesville shale

During 2010, we spud 119 horizontal Haynesville shale wells, primarily in our core DeSoto Parish, Louisiana area. Our 2010 activities were characterized by improving our drilling efficiencies, collaborating with other producers in the area to achieve best-practices, reducing costs and implementing new technologies and processes such as micro-seismic, pad drilling and simultaneous fracture stimulation of wells within a unit. As discussed below, we completed two significant acquisitions with BG Group of prospective acreage in Shelby, Nacogdoches and San Augustine Counties in East Texas, or the Shelby Area. The Shelby Area is our second focus area in the Haynesville/Bossier shale. By December 31, 2010, we were running 21 operated horizontal drilling rigs in our two focus areas and expect to run 22 operated drilling rigs throughout 2011.

On May 14, 2010, we jointly closed with BG Group the purchase of Common Resources, L.L.C., or the Common Transaction, consisting of properties in Shelby, San Augustine and Nacogdoches Counties, Texas in the Haynesville and Bossier shales. The total purchase price paid at closing was approximately $442.1 million ($221.0 million net to EXCO). Our share of the acquisition price was financed with borrowings under our credit agreement, or the EXCO Resources Credit Agreement.

On June 30, 2010, we jointly closed with BG Group the purchase of properties in Shelby, San Augustine and Nacogdoches Counties, Texas in the Haynesville and Bossier shales from Southwestern Energy Company, or the Southwestern Transaction. The purchase price paid at the closing was $357.8 million ($178.9 million net to EXCO). Our share of the acquisition price was financed with borrowings under the EXCO Resources Credit Agreement. The development of these assets is governed by the East Texas/North Louisiana JV. The majority of the assets acquired in the Southwestern Transaction represent additional working interests in properties that EXCO and BG Group acquired in the Common Transaction.

Marcellus shale

During 2010, our key accomplishments in the Marcellus shale include the Appalachia JV, drilling 15 appraisal wells and improvements in drilling days and completion metrics. The appraisal wells have allowed us to rank our acreage in the area and in 2011 we will further confirm the acreage and identify key acquisition targets. Our 2011 plans involve further analyses to increase our technical understanding of the shale play, evaluate seismic data and evolve into an accelerated development program. In December 2010, we entered into the Chief Transaction which closed in January 2011. We have a pending acquisition prospective of Marcellus shale development which we expect to close during the first quarter of 2011.

Appalachia JV

On June 1, 2010, we closed the Appalachia JV, which resulted in the sale of a 50% undivided interest in substantially all of our Appalachian oil and natural gas proved and unproved properties and related assets to BG Group. Using our current estimated post closing adjustments of $45.0 million due to BG Group, the net cash consideration is approximately $790.2 million. We expect the final purchase price adjustments to be completed in 2011. In addition to the cash consideration received at closing, BG Group agreed to fund the Appalachia Carry, which is equal to 75% of our share of deep drilling and completion costs within the Appalachia JV until the carry amount is satisfied up to a total of $150.0 million. As of December 31, 2010, the unused balance of the Appalachia Carry is estimated to be approximately $126.8 million after giving consideration to estimated contractual reductions of $10.6 million to the carry for estimated post closing adjustments. In conjunction with the Appalachia JV, we entered into a joint development agreement with BG Group. The effective date of the transaction was January 1, 2010.

EXCO and BG Group each own a 50% interest in OPCO, which operates the properties located within the Appalachia JV, subject to oversight from a management board having equal representation from EXCO and BG Group. During 2010, we advanced $48.0 million to OPCO to provide working capital for our share of the Appalachia JV operations. We will continue to fund OPCO with advances to develop the Appalachia properties.

In addition to the upstream Appalachia properties, certain midstream assets were transferred to the Appalachia Midstream JV through which both EXCO and BG Group will pursue the construction and expansion of gathering systems, pipeline systems and treating facilities for anticipated future production from the Marcellus shale.

Debt summary

A summary of our outstanding long-term debt as of February 17, 2011 and December 31, 2010 and a brief description of our credit agreement and senior notes is presented below.

(in thousands)	February 17, 2011	December 31, 2010
EXCO Resources Credit Agreement	$ 549,000	$ 849,000
2018 Notes	750,000	750,000
Unamortized discount on 2018 Notes	(10,594)	(10,731)
Total debt	$1,288,406	1,588,269

EXCO Resources Credit Agreement

The EXCO Resources Credit Agreement, as amended, matures on March 30, 2014 and has a borrowing base of $1.0 billion as of December 31, 2010.

The outstanding balance under the EXCO Resources Credit Agreement as of February 17, 2011 reflects a reduction of $300.0 million due primarily to a distribution from TGGT and BG Group's election to participate for their 50% share of the Chief Transaction.

2018 Notes

On September 15, 2010 we closed an underwritten offering of $750.0 million aggregate principal amount of 7.5% senior unsecured notes maturing on September 15, 2018. We received proceeds of approximately $724.1 million from the offering after deducting an original issue discount, commissions and offering fees and expenses. The net proceeds from the offering were used to redeem the 2011 Notes with the remaining balance being used to pay a portion of the outstanding balance under the EXCO Resources Credit Agreement. The 2018 Notes are guaranteed on a senior unsecured basis by EXCO's consolidated subsidiaries, which excludes EXCO Water Resources, LLC and all of our jointly-held equity investments with BG Group. All of our non-guarantor subsidiaries are considered unrestricted subsidiaries under the 2018 Notes, with the exception of our equity investment in OPCO.

Summary of geographic areas of operations

The following tables set forth summary operating information attributable to our principal geographic areas of operation as of December 31, 2010:

Areas	Total Proved Reserves (Bcfe)(1)	PV-10 (in millions)(1)(2)	Annual daily net production (Mmcfe)	Reserve Life (years)
East Texas/North Louisiana	1,289.1	$1,035.7	261.5	13.5
Appalachia	114.5	79.1	25.8	12.1
Permian and other	95.5	241.7	19.6	13.3
Total	1,499.1	$1,356.5	306.9	13.4

Areas	Identified drilling locations(3)	Identified exploitation projects(4)	Total gross acreage	Total net acreage(5)
East Texas/North Louisiana	5,956	984	291,419	146,073
Appalachia	5,619	102	814,843	376,384
Permian and other	358	21	162,381	126,340
Total	11,933	1,107	1,268,643	648,797

(1) The total Proved Reserves and PV-10 for non-shale properties, excluding future plugging and abandonment costs, of the Proved Reserves, as used in this table, were prepared by Lee Keeling and Associates, Inc., or Lee Keeling, an independent petroleum engineering firm located in Tulsa, Oklahoma. The total Proved Reserves and PV-10 for shale properties, excluding future plugging and abandonment costs, as used in the table, were prepared by Haas Petroleum Engineering Services, Inc., or Haas Engineering, an independent petroleum engineering firm located in Dallas, Texas. For each area set forth in the table, the Proved Reserves were extracted from the reports from Lee Keeling and Haas Engineering by our internal engineers. The estimated future plugging and abandonment costs necessary to compute PV-10 were computed internally.

(2) The PV-10 data used in this table is based on the simple average of the spot prices for the trailing twelve month period using the first day of each month beginning on January 1, 2010 and ended on December 1, 2010, of $4.38 per Mmbtu for natural gas and $79.43 per Bbl for oil, in each case adjusted for geographical and historical differentials. Market prices for oil and natural gas are volatile. See "Item 1A. Risk factors—Risks relating to our business." We believe that PV-10 before income taxes, while not a financial measure in accordance with generally accepted accounting principles, or GAAP, is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The total Standardized Measure, a measure recognized under GAAP, for our Proved Reserves as of December 31, 2010 was $1.2 billion. The Standardized Measure represents the PV-10 after giving effect to income taxes, and is calculated in accordance with Accounting Standards Codification Topic 932, "Extractive Activities—Oil and Gas," or ASC 932. The amount of estimated future plugging and 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.

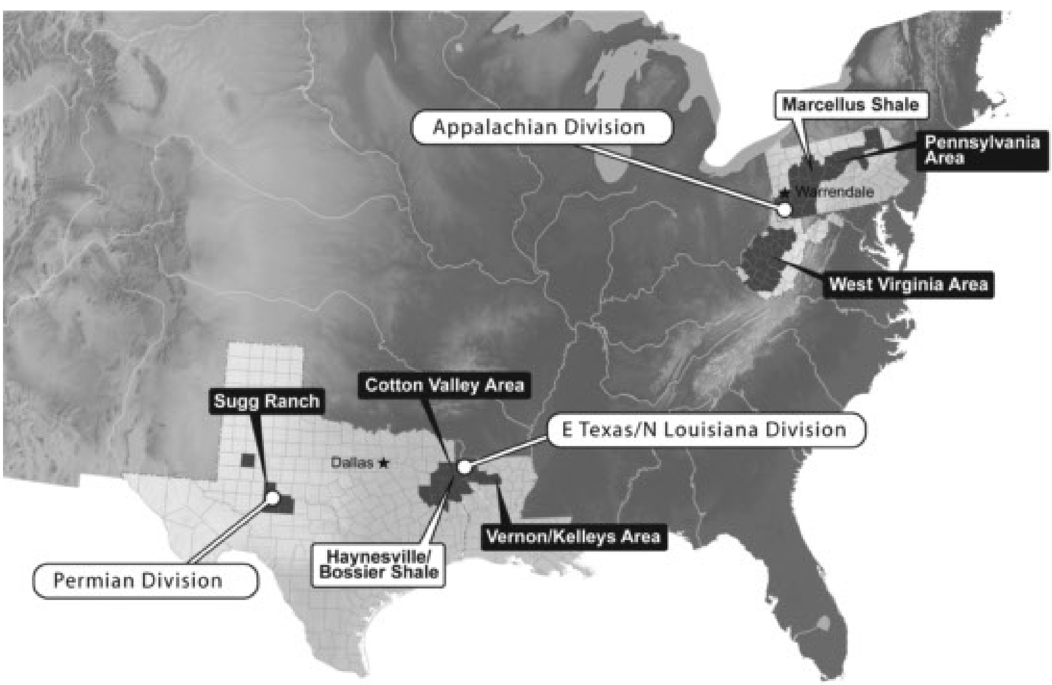
(in millions)	At December 31, 2010	2009	2008
PV-10	$1,356.5	$747.7	$2,473.5
Future income taxes	(305.1)	—	(649.8)
Discount of future income taxes at 10% per annum	172.0	—	412.6
Standardized Measure	$1,223.4	$747.7	$2,236.3

(3) 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, 1,303 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."

(4) 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, 405 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."

(5) Includes 72,320, 24,752 and 10,714 net acres with leases expiring in 2011, 2012 and 2013, respectively.

Our development and exploitation project areas



East Texas/North Louisiana

The East Texas/North Louisiana area is comprised of the Haynesville and Bossier shale plays and the Cotton Valley sand trend, which covers portions of the East Texas Basin and the Northern Louisiana Salt Basin. East Texas/North Louisiana is our largest division in terms of production and reserves and our primary targets include the Haynesville and Bossier shales. We also have production from the Cotton Valley, Travis Peak, Pettet and Hosston formations. We continue to seek additional acreage that is complementary to our existing acreage, operations and pipeline infrastructure.

Currently, our emphasis is on exploitation of our acreage in the Haynesville shale play where we hold approximately 76,000 net acres. The Haynesville shale is at depths of 12,000 to 14,000 feet and is being developed with horizontal wells that typically have 4,000 to 5,000-foot laterals resulting in 16,000 to 19,000 feet of total depth.

We continue to produce from tight gas sand reservoirs in the Cotton Valley sand trend at depths of 6,500 to 15,000 feet. Operations in the area are generally characterized by long-life reserves and high drilling success rates.

Haynesville shale

The Haynesville shale play is one of the most active natural gas plays in the United States. Our Haynesville shale acreage is primarily located in DeSoto and Caddo Parishes in Louisiana and in Harrison, Panola, Shelby, San Augustine and Nacogdoches Counties in Texas. A substantial portion of our acreage is held by our existing Haynesville, Cotton Valley, Hosston and Travis Peak production.

Our development program in the Haynesville shale play is concentrated in DeSoto Parish, Louisiana and the recently acquired in the Shelby Area. We are developing our core DeSoto Parish position on 80-acre spacing in a manufacturing mode utilizing multi-well pad development. In the Shelby Area, our efforts are focused on delineating our position, establishing units and holding our acreage. Although we will be developing some units in 2011, we expect to transition the development of the Shelby Area acreage to full manufacturing mode in 2012.

In early 2010, we operated 12 horizontal drilling rigs in the play and we ended 2010 with 21 operated horizontal drilling rigs. In January 2011 we added one rig bringing our total operated horizontal rig count to 22 rigs. We plan to drill approximately 163 operated horizontal wells in 2011 with our 22 rig fleet. From late 2008 to year end 2010, we have spud 164 operated horizontal wells and produced more than 200 Bcf of gross natural gas to sales. At year end 2010, we averaged a gross operated daily shale gas production rate of approximately 722 Mmcf per day. Including non-operated volumes, we exited 2010 with a net Haynesville production rate of 236.8 Mmcf per day.

In DeSoto Parish our development program has made a transformation from a testing and delineation program to a full field development program. In mid 2010 we initiated a manufacturing process with full unit development on 80-acre spacing. In June 2010 we completed our first four well, 80-acre spacing test across 320 acres, and we completed our first eight well, 80-acre spacing test across a full 640 acre unit in October 2010. Our manufacturing process typically involves four drilling rigs per 640 acre unit to simultaneously drill all wells in the unit, followed by two to three fracture stimulation fleets to simultaneously complete all wells in the unit. We believe this approach to full field development maximizes value and recovery of the resource. At year end 2010, we had 12 units in progress for full 80-acre development and plan to target an additional 15 units in 2011. The multi-well pad design minimizes surface impact and provides for a more capital efficient gathering and production system layout than can be achieved with single well locations. In late 2010 we commissioned a 12 mile, 24 inch diameter water distribution line which utilizes effluent water from a local paper mill to support our completion operations. We recently used this line to simultaneously provide the necessary water to three fracture stimulation fleets located in the same section as we completed seven wells.

In 2010, we acquired a significant acreage position in Shelby, San Augustine and Nacogdoches Counties, Texas and we now hold 24,000 net acres in this second core area of the Haynesville shale play. By year end 2010 we had six drilling rigs running in the area and a total of 19 horizontal wells flowing to sales with a total gross production rate of approximately 100 Mmcf per day (34 Mmcf per day net). At the time of the initial acquisition, gross production in this area was 34 Mmcf per day (7 Mmcf per day net). Some of our recent Haynesville shale wells have yielded results comparable to our DeSoto Parish area. In the fourth quarter 2010, we turned seven new wells to sales in this area. Notable highlights for the quarter included completing and turning to sales two wells with initial rates of 23 and 28 Mmcf per day. Our 2011 development plan for this area has a strong focus on evaluation and delineation. By year end 2011 we expect all of our core San Augustine and Nacogdoches acreage to be held by production.

Our operational focus has resulted in significant improvements in drilling and completion efficiencies. In late 2010, in our DeSoto Parish area, we achieved our best drilling time performance to date of 28 days from spud to rig release. This was accomplished by the most consistent and experienced modern flex rig in our fleet, the same rig that drilled our first horizontal well in 2008. We have recently set several drilling records in the play including single bit runs from surface to intermediate hole depth and single bit runs from intermediate to production hole total depth, typically 16,500 ft.

We continue to use the latest technologies to enhance our shale development. We recently completed 168 square miles of 3-D seismic in DeSoto Parish and acquired another 126 square miles in the Shelby Area. In 2010, we monitored five wells with micro-seismic and another 19 wells with our buried array monitoring system. In our completion evaluation process, we gathered production logs on 10 horizontal wells and conducted tracer evaluations on 17 horizontal wells. In 2010, we also drilled a dedicated vertical pressure monitoring well and installed permanent down hole gauges to measure and monitor the reservoir pressure in the Haynesville shale.

In addition to our success in reducing well costs with drilling time improvements and efficiencies, we are also focused on optimizing completions. Almost 50% of our well cost is incurred during the completion phase. We plan to implement cost effective and efficient design changes as part of our manufacturing program. We are utilizing four dedicated fracture stimulation fleets and continue to see greater consistency and efficiencies in our fracturing operations. These commitments have provided consistent availability of completion equipment and personnel available to us, and we have maintained a proper alignment with our drilling to keep a low inventory of wells waiting on completion. At December 31, 2010, we had 17 wells in our completion inventory which is low considering our drilling activity level and pad development process. We target a minimum working inventory of completions and design our program to flow gas directly to the sales line once the well is completed. We have no wells currently waiting on pipeline. This is possible due to close coordination with our jointly-held midstream company, TGGT, which installs the gathering lines in concert with our drilling operations in most of our development areas.

Bossier shale

The Bossier shale that overlies the Haynesville shale is a significant resource that is present across most of our acreage. We drilled and tested two horizontal Bossier wells in our core DeSoto Parish area during 2010 with initial flow rates of 11 and 13 Mmcf per day. We will continue to monitor well performance of these two wells before we begin additional testing in this area. In the Shelby Area we drilled our first EXCO operated Bossier well in the fourth quarter 2010 and are presently testing the well. Additional Bossier testing for the Shelby Area will be conducted during 2011.

Cotton Valley, Hosston, Travis Peak, Pettet

The Vernon Field in Jackson Parish, Louisiana produces from the lower Cotton Valley and Bossier Sand formations at depths ranging from 12,000 to 15,000 feet. For 2010, the Vernon Field represented 24.2% of our company wide net production. The technical expertise obtained in the development of the Vernon Field and the exploitation of these high-pressure, high-temperature reservoirs greatly assisted in the rapid development of the Haynesville shale. The current focus in the Vernon Field is maintaining production and minimizing our operating expense. Within the past year, we have reduced our production decline rate.

We have acreage and production in Caddo and DeSoto Parishes, Louisiana, primarily in four fields—Holly, Kingston, Caspiana and Longwood. We also have acreage and production in Harrison, Panola, Gregg and Rusk Counties in Texas, primarily across five fields—Carthage, Waskom, Oak Hill, Minden and Danville. We are focused on producing primarily from Cotton Valley sands at depths ranging from 10,400 to 11,000 feet and the Travis Peak and Hosston Sands at 7,800 to 10,000 feet.

Due to low commodity prices, we are not actively drilling in these formations. We plan to conduct 25 recompletions in the DeSoto Parish area in 2011, primarily targeting the upper Cotton Valley and Hosston intervals. We maintain a strong emphasis on base production performance and focus on operating expense reductions. We typically run multiple service rigs replacing tubing, changing pumps, cleaning out fill and implementing general repairs to maintain optimum production levels.

Appalachia

The Appalachian Basin includes portions of the states of Kentucky, New York, Ohio, Pennsylvania, Virginia, West Virginia and Tennessee and covers an area of over 185,000 square miles. The Appalachian Basin is strategically located near the high energy demand markets of the northeast United States and, as a result, the natural gas produced from the area has typically commanded a higher wellhead price relative to other North American natural gas areas.

Most production in the Appalachian Basin has been traditionally derived from relatively shallow, low porosity and low permeability sand and shale formations at depths from approximately 1,000 to over 8,000 feet. Assets in the area are typically characterized by long reserve lives, high drilling success rates, and a large number of low productivity wells with shallow decline rates. Our operations in the area have primarily included maintaining our existing production from shallow wells and testing our Marcellus shale acreage.

The emergence of the Marcellus shale play over the last several years resulted in a shift in our focus from the traditional shallow development to exploration and development of the Marcellus shale. We currently hold approximately 350,000 net acres in the Appalachian Basin.

Marcellus shale

In June 2010, we closed our Appalachian joint venture with BG Group. Subsequently, the joint venture has positioned itself with key staff and resources to execute an appraisal and development program. During 2010, we spud 15 wells and completed 10 gross (4.9 net), with a 100% success rate. The 2010 program was a combination of appraisal and development wells in our east central and west central Pennsylvania areas. The development wells in west central Pennsylvania had initial production rates ranging from 3.7 to 6.3 Mmcf per day from lateral lengths varying from 2,500 to 5,700 feet. The east central Pennsylvania area had lower initial production rates ranging from 1.5 to 4.0 Mmcf per day from lateral lengths varying from 2,500 to 4,900 feet. A significant amount of data was collected and is being used to formulate a development plan based on these preliminary performance results in each area.

We continue to build our core positions in west central and northeast Pennsylvania. Concurrently, development capital will be focused in these areas, particularly where we have realized strong results, have significant acreage, and have market access that is either existing or currently under construction. We are adding to both positions with the acquisition of approximately 56,000 net acres in northeast Pennsylvania from Chief Oil & Gas LLC and the pending acquisition of approximately 32,000 net acres in west central Pennsylvania. These acquisitions are significant additions to our existing portfolio and provide years of multi-rig development inventory. The most recent completion on our northeast Pennsylvania acquired acreage is the best well in our Marcellus shale portfolio, and it recently produced to sales at a rate of approximately 10 Mmcf per day at 3,900 psi.

We continue to see improvement in all cost performance metrics. Total well costs are down 20% for 2010 with meaningful reductions in both drilling and completion costs. Improvements in drilling times, water management infrastructure, efficiencies due to multi-well pad drilling and single sourcing are among the key drivers to our cost reductions in 2010. These metrics will continue to improve as infrastructure is added, development activity is increased, and key findings from our 2010 program are implemented.

We currently have two horizontal drilling rigs operating in the basin with plans to exit 2011 with 4-5 operated rigs. The 2011 drilling plan includes both an appraisal program across parts of our acreage position and a three rig program in our development areas. We plan to drill 12 gross (6.0 net) operated appraisal wells, 52 gross (17.9 net) operated development wells and participate in 4 gross (0.3 net) outside operated wells during 2011, while spending net drilling and completion capital totaling $38 million. All of our planned 2011 drilling activity is located in areas which have sufficient gas markets and immediate take away capacity or a defined strategy to be sales ready by year end 2011.

Pennsylvania area

Our Pennsylvania area encompasses 27 counties. Drilling, completion and production activities target the Marcellus shale as well as the Upper Devonian, Venanago, Bradford and Elk sandstone groups at depths from 1,800 to 8,100 feet. We plan to drill 64 gross operated Marcellus shale wells in the Pennsylvania area during 2011.

West Virginia area

Our West Virginia area includes 30 counties and stretches from the northern to the southern areas of the state. Drilling, completion and production activities target the Marcellus shale and multiple reservoirs of the Mississippian and Devonian formations found at depths ranging from 1,500 to 8,100 feet. During 2011, we plan to participate in 4 gross (0.3 net) outside operated horizontal Marcellus wells.

Permian

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

Sugg Ranch Field

The Sugg Ranch Field is located primarily in Irion County, Texas. We have a total working interest of 96.0% in the property. At December 31, 2010, we had Proved Reserves of 93.8 Bcfe and 334 gross producing wells. Production is primarily from the Canyon Sand from depths of 6,700 to 7,900 feet. We currently plan to use two operated vertical rigs to drill 72 gross (69.8 net) wells in 2011.

Our oil and natural gas reserves

Changes in our Proved Reserves for the year ended December 31, 2010 were impacted by the following significant factors and events:

- significant additions of new Proved Reserves, particularly Proved Undeveloped Reserves, arising from our drilling of horizontal wells in the Haynesville shale and the transition from 160-acre spacing to 80-acre spacing development in our core DeSoto Parish area. As a result of the successful development drilling in this area, we have 706.8 Bcfe of Proved Reserves in the Haynesville shale play as of December 31, 2010 compared with 153.8 Bcfe at December 31, 2009; and
- our Appalachia JV resulted in the sale of an undivided 50% interest in our oil and natural gas assets in Appalachia, which included approximately 133.1 Bcfe of Proved Reserves which were largely represented by shallow wells.

The following table summarizes Proved Reserves at December 31, 2010, 2009 and 2008. This information was prepared in accordance with the rules and regulations of the Securities and Exchange Commission, or the SEC.

	At December 31,		
	2010	2009	2008
Oil (Mmbbls)			
Developed	4.6	3.5	14.8
Undeveloped	2.7	2.0	6.0
Total	7.3	5.5	20.8
Natural Gas (Bcf)			
Developed	794.0	622.2	1,354.8
Undeveloped	661.3	303.6	460.3
Total	1,455.3	925.8	1,815.1
Equivalent reserves (Bcfe)			
Developed	821.6	643.2	1,443.6
Undeveloped	677.5	315.6	496.3
Total	1,499.1	958.8	1,939.9
PV-10 (in millions)(1)			
Developed	$1,187.2	$649.8	$2,375.7
Undeveloped	169.3	97.9	97.8
Total	$1,356.5	$747.7	$2,473.5
Standardized Measure (in millions)(2)	$1,223.4	$747.7	$2,236.3

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

	Average and spot price(a)	
Date	Natural gas (per Mmbtu)	Oil (per Bbl)
December 31, 2010	$4.38	$79.43
December 31, 2009	3.87	61.18
December 31, 2008	5.71	44.60

(a) The prices for 2010 and 2009 are the average spot prices for the trailing twelve month periods per Mmbtu at Henry Hub and per Bbl at Cushing, Oklahoma, using the first day of each month beginning on January 1 and ending on December 1 of each respective year. The prices for 2008 represent the December 31, 2008 spot price per Mmbtu at Henry Hub and per Bbl at Cushing, Oklahoma.

(2) There is no difference in Standardized Measure and PV-10 as of December 31, 2009 as the impacts of lower natural gas prices, net cash flows and net operating loss carry-forwards eliminated estimated future income taxes.

We believe that PV-10 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 due to tax characteristics, which can differ significantly, among comparable companies. The Standardized Measure represents the PV-10 after giving effect to income taxes, and is calculated in accordance with ASC 932. The following table provides a reconciliation of our PV-10 to our Standardized Measure:

(in millions)	
PV-10	$1,356.5
Future income taxes	(305.1)
Discount of future income taxes at 10% per annum	172.0
Standardized Measure	$1,223.4

Management has established, and is responsible for, internal controls designed to provide reasonable assurance that the estimates of Proved Reserves are computed and reported in accordance with rules and regulations promulgated by the SEC as well as established industry practices used by independent engineering firms and our peers. These internal controls include documented process workflows, qualified professional engineering and geological personnel with specific reservoir experience and investment in on-going education with emphasis on emerging technologies. These emerging technologies are of particular importance as they relate to our shale plays. Our internal audit function routinely tests our processes and controls and estimated Proved Reserve computations. We also retain outside independent engineering firms to prepare estimates of our Proved Reserves. Senior management reviews and approves our reserve estimates, whether prepared internally or by third parties. Our Vice President of Engineering oversees our outside independent engineering firms, Lee Keeling and Haas Engineering, in connection with the preparation of estimates of our Proved Reserves. Our Vice President of Engineering is a registered Professional Engineer and has served in various leadership roles with the Gas Research Institute, the Society of Petroleum Engineers and the Society of Women Engineers over her 32 years in the oil and gas industry. She is a graduate of Pennsylvania State University (1978) with a degree in Petroleum and Natural Gas Engineering. During her career, our Vice President of Engineering has been involved in oil and natural gas reserves analysis and estimation for both major oil companies and independents. Our Chief Operating Officer and our Vice President of Engineering, with input from other members of senior management, are responsible for the selection of our third-party engineering firms and receive the reports generated by such firms. The third-party engineering reports are provided to our audit committee, which meets routinely with the engineering firms to review and discuss the procedures for determining the estimates of our oil and natural gas reserves.

The estimates of Proved Reserves and future net cash flow for our non-shale properties as of December 31, 2010, 2009 and 2008 have been prepared by Lee Keeling. Our estimated Proved Reserves and future net cash flows for our shale properties were prepared by Haas Engineering for 2010 and 2009. Lee Keeling and Haas Engineering are independent petroleum engineering firms that perform a variety of reserve engineering and valuation assessments for public and private companies, financial institutions and institutional investors. Lee Keeling has performed these services for over 50 years and Haas Engineering was founded in 1980. We selected Haas Engineering to prepare our estimates of Proved Reserves for our shale properties based upon its specific experience in performing services for industry peers with shale operations. Our internal technical employees responsible for reserve estimates and interaction with our independent engineers include corporate officers with petroleum and other engineering degrees, professional certifications and industry experience similar to those of our independent engineering firms. The estimates of future plugging and abandonment costs necessary to compute PV-10 and Standardized Measure were computed internally. Estimates of oil and natural gas reserves are projections based on a process involving an independent third party engineering firm's extensive visits, collection of any and all required geological, geophysical, engineering and economic data, and such firm's complete external preparation of all required estimates and are forward-looking in nature. These reports rely on various assumptions, including definitions and economic assumptions required by the SEC, including the use of constant oil and natural gas pricing, use of current and constant operating costs and current capital costs. We also make assumptions relating to availability of funds and timing of capital expenditures for development of our

Proved Undeveloped Reserves. 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 23. Supplemental information relating to oil and natural gas producing activities (unaudited)" of the notes to our consolidated financial statements for additional information regarding our oil and natural gas reserves and our Standardized Measure.

Lee Keeling and Haas Engineering also examined our estimates with respect to reserve categorization, using the definitions for Proved Reserves set forth in SEC Regulation S-X Rule 4-10(a) and SEC staff interpretations and guidance. In preparing an estimate of our Proved Reserves and future net cash flows attributable to our interests, Lee Keeling and Haas Engineering did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of the examination something came to the attention of Lee Keeling or Haas Engineering which brought into question the validity or sufficiency of any such information or data, Lee Keeling or Haas Engineering did not rely on such information or data until they had satisfactorily resolved their questions relating thereto or had independently verified such information or data. Lee Keeling and Haas Engineering determined that their estimates of Proved Reserves conform to the guidelines of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of Proved Reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(24) of SEC Regulation S-X.

Management's discussion and analysis of oil and natural gas reserves

The following discussion and analysis of our proved oil and natural gas reserves and changes in our Proved Reserves is intended to provide additional guidance on the operational activities, transactions, economic and other factors which significantly impacted the determination of our estimate of Proved Reserves as of December 31, 2010 and changes in our Proved Reserves during 2010. This discussion and analysis should be read in conjunction with "Note 23. Supplemental information relating to oil and natural gas producing activities (unaudited)" and in "Risk factors" addressing the uncertainties inherent in the estimation of oil and natural gas reserves elsewhere in this Annual Report on Form 10-K. The following table summarizes the significant changes in our Proved Reserves from January 1, 2010 to December 31, 2010.

(in thousands)	Oil (Bbls)	Natural gas (Mcf)	Equivalent natural gas (Mcfe)
Proved developed	4,633	793,777	821,575
Proved undeveloped	2,725	661,176	677,526
Total	7,358	1,454,953	1,499,101
The changes in reserves for the year are as follows:			
January 1, 2010	5,518	925,728	958,836
Purchase of reserves in place	—	30,047	30,047
Extensions and discoveries	1,631	635,841	645,627
Revisions of previous estimates:			
Changes in price	751	48,630	53,136
Changes in performance	549	63,089	66,383
Sales of reserves in place	(403)	(140,504)	(142,922)
Production	(688)	(107,878)	(112,006)
December 31, 2010	7,358	1,454,953	1,499,101

Current year oil and natural gas production

Total oil and natural gas production in 2010 was 112.0 Bcfe, which includes approximately 29.4 Bcfe in production from 2010 extensions and discoveries that were not reflected in our beginning of the year Proved Reserves.

Sales of reserves in place

During 2010, we entered into the Appalachia JV which resulted in the sale of an undivided 50% interest in our oil and natural gas assets in Appalachia of approximately 133.1 Bcfe of Proved Reserves.

New discoveries and extensions

EXCO had additions to Proved Reserves through extensions and discoveries in 2010 of 645.6 Bcfe. Of this total, 592.7 Bcfe, or 91.8%, of the extensions and discoveries, were predominantly from our Haynesville shale play activities, including 565.1 Bcfe in our core DeSoto Parish area and 27.6 Bcfe in the Shelby Area. During 2010, we began developing our core DeSoto Parish area on 80-acre spacing in a manufacturing mode utilizing multi-pad development. This area has demonstrated consistent well performance and EXCO has 63 contiguous operated sections under development. By the end of 2010, we had 14 wells on 80-acre spacing patterns and we expect to have 11 sections fully developed in the first quarter of 2011. Estimated ultimate recovery, or EUR, is based on production performance analysis and supported with reliable technologies such as seismic, microseismic, reservoir simulation, pressure transient and volumetric analysis. Our core DeSoto Parish area proved undeveloped locations were booked using a probabilistic approach as of December 31, 2010, resulting in an average of 2.7 offsetting proved undeveloped locations, each having an average EUR of 6.1 Bcfe, for each producing well drilled. As a result, the gross EUR from these Haynesville wells on a 640-acre unit increased to 48.8 Bcfe at year end 2010 compared with 26.4 Bcfe at year end 2009. As of December 31, 2010, our Proved Undeveloped Reserves represent 45.2% of our Proved Reserves with the Haynesville shale representing approximately 71.9% of our total Proved Undeveloped Reserves at year end.

Revisions of previous estimates

Revisions in 2010 include positive revisions due to prices and other economic factors of 53.1 Bcfe. Net positive revisions resulting from performance factors were 66.4 Bcfe. In East Texas/North Louisiana we had positive revisions of 75.0 Bcfe, primarily due to an improvement in the decline rate in our Vernon Field. We also had positive performance revisions in our Permian division of 13.7 Bcfe resulting from better than expected well performance. These positive revisions were partially offset by decreases of approximately 22.3 Bcfe in our Appalachia area, primarily in Proved Undeveloped Reserves.

Proved Undeveloped Reserves

The following table summarizes the changes in our Proved Undeveloped Reserves, all of which are expected to be developed within five years, for the year ended December 31, 2010:

(all amounts are in Mmcfe)	
Proved Undeveloped Reserves at January 1, 2010	315,646
Purchases of Proved Undeveloped reserves in place	—
Sales of Proved Undeveloped Reserves in place during year	(52,557)
New discoveries and extensions(1)	440,239
Proved Undeveloped Reserves transferred to developed(2)	(32,386)
Revisions of previous estimates of Proved Undeveloped Reserves(3)	6,584
Proved Undeveloped Reserves at December 31, 2010	677,526

(1) Approximately 95.5% of the discoveries and extensions of Proved Undeveloped Reserves in 2010 occurred in our East Texas/North Louisiana region, primarily in our Haynesville shale play.

(2) 29.4 Bcfe of Proved Undeveloped Reserves transferred to Proved Developed Reserves in 2010 related to our Haynesville shale reserves in East Texas/North Louisiana. Capital costs incurred to convert Proved Undeveloped Reserves to Proved Developed Reserves were $85.2 million.

(3) Net positive revisions in our Proved Undeveloped Reserves resulted from pricing and costs of 22.8 Bcfe and were partially offset by net negative performance revisions of 16.2 Bcfe, primarily associated with conventional shallow Appalachia undeveloped locations.

Impacts of 2010 changes in reserves on depletion rate and statements of operations

For the year ended December 31, 2010, there were no transactions or other Proved Reserve changes that had a significant impact on depreciation, depletion and amortization.

East Texas/North Louisiana Carry

We received a positive impact on our full cost pool amortization rate in 2010 from the East Texas/North Louisiana Carry. However, the impact of future development costs for proved undeveloped reserve additions, which are not subject to a carry, more than offset the 2010 benefits. As a result, our depletion rate increased during 2010. With the completion of carry commitment in East Texas/North Louisiana, we would anticipate an increase in our depletion rate in 2011 and subsequent periods.

Our production, prices and expenses

The following table summarizes revenues, 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.

	Year ended December 31,		
(in thousands, except production and per unit amounts)	**2010**	**2009**	**2008**
Revenues, production and prices:			
Oil:			
Revenue(1)	$ 52,411	$ 84,397	$ 216,727
Production sold (Mbbl)(2)	688	1,571	2,236
Average sales price per Bbl(1)	$ 76.18	$ 53.72	$ 96.93
Natural gas:			
Revenue(1)	$462,815	$466,108	$1,188,099
Production sold (Mmcf)(2)	107,878	118,736	131,159
Average sales price per Mcf(1)	$ 4.29	$ 3.93	$ 9.06
Costs and expenses:			
Average production cost per Mcfe (excluding severance and ad valorem taxes)	$ 0.75	$ 1.08	$ 1.11
General and administrative expense per Mcfe	$ 0.94	$ 0.77	$ 0.61
Depreciation, depletion and amortization per Mcfe	$ 1.75	$ 1.72	$ 3.18

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

(2) Significant fields representing 15% or more of our total Proved Reserves at end of year:

	Year ended December 31,		
	2010	2009	2008
Vernon Field:			
Oil production sold (Mbbls)	5	4	7
Natural gas production sold (Mmcf)	27,122	35,146	43,519
Average price per Bbl	$ 78.68	$ 58.95	$105.64
Average price per Mcf	$ 4.31	$ 3.57	$ 8.45
Average production cost per Mcfe (excluding severance and ad valorem taxes)	$ 1.06	$ 0.83	$ 0.62
Haynesville shale:			
Natural gas production sold (Mmcf)	55,298	14,917	*
Average price per Mcf	$ 3.96	$ 3.21	*
Average production cost per Mcfe (excluding severance and ad valorem taxes)	$ 0.09	$ 0.10	*

* Less than 15% of total reserves.

Our interest in productive wells

The following table quantifies 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 refer to the total number of physical wells in which we hold a working interest, 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 by totaling the percentage interests we hold in all our gross wells.

	At December 31, 2010					
	Gross wells(1)			Net wells		
Areas	Oil	Gas	Total	Oil	Gas	Total
East Texas/North Louisiana	59	1,407	1,466	28.7	745.1	773.8
Appalachia	358	5,534	5,892	174.9	2,553.0	2,727.9
Permian and other	305	67	372	285.7	46.3	332.0
Total	722	7,008	7,730	489.3	3,344.4	3,833.7

(1) As of December 31, 2010, we held interests in 10 gross wells with multiple completions.

As of December 31, 2010, we were the operator of 7,276 gross (3,774.3 net) wells, which represented approximately 96.8% of our proved developed producing reserves as of December 31, 2010.

Our drilling activities

In 2010 and 2009, our drilling activities were primarily focused on horizontal drilling in shale plays, particularly in the Haynesville/Bossier and Marcellus shales.

The following tables summarize our approximate gross and net interests in the wells we drilled during the periods indicated and refer to the number of wells completed at any time during the period, regardless of when drilling was initiated. At December 31, 2010, we had 26 gross (11.3 net) wells being drilled and 11 gross (5.6 net) wells being completed. In addition to the wells being completed, at December 31, 2010, we had 37 gross (18.0 net) wells waiting to be completed.

	Development Wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2010	171	0	171	83.4	0	83.4
Year ended December 31, 2009	82	1	83	40.8	0.9	41.7
Year ended December 31, 2008	447	4	451	374.2	2.5	376.7

	Exploratory Wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2010(1)	34	2	36	13.8	2.0	15.8
Year ended December 31, 2009	19	1	20	12.2	1.0	13.2
Year ended December 31, 2008	20	4	24	19.3	3.5	22.8

(1) Our 2010 exploratory wells include Haynesville shale wells located outside of our DeSoto Parish and southern Caddo Parish, Louisiana areas, all East Texas counties and all Marcellus shale wells. We also classify our Bossier shale test wells as exploratory projects. Haynesville shale drilling in DeSoto Parish and southern Caddo Parish, Louisiana has been classified as development.

Our developed and undeveloped acreage

Developed acreage includes those acres spaced or assignable to producing wells. Undeveloped acreage represents those acres that do not currently have completed wells capable of producing commercial quantities of oil or natural gas, regardless of whether the acreage contains Proved Reserves. The definitions of gross acres and net acres conform to how we determine gross wells and net wells. The following table sets forth our developed and undeveloped acreage at December 31, 2010:

	At December 31, 2010			
	Developed acreage		Undeveloped acreage	
Areas	Gross	Net	Gross	Net
East Texas/North Louisiana	194,720	98,272	96,699	47,801
Appalachia	355,815	161,660	459,028	214,724
Permian and other	26,749	25,811	135,632	100,529
Total	577,284	285,743	691,359	363,054

The primary terms of our oil and natural gas leases expire at various dates. Much 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 or comply with certain lease terms. Upon ceasing production, these leases will expire. We have 72,320, 24,752 and 10,714 net acres with leases expiring in 2011, 2012 and 2013, 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, as well as other non-producing formations, in a given oil or natural gas field without the necessity of purchasing additional leases or producing properties.

Sales of producing properties and undeveloped acreage

We periodically review our properties to identify cost savings opportunities and divestiture candidates. We actively seek to dispose of properties with higher operating costs, properties that are not within our core geographic operating areas and properties that are not strategic. We also seek to opportunistically divest properties in areas in which acquisitions and investment economics no longer meet our objectives.

Equity investments

Midstream operations

EXCO and BG Group each own a 50% interest in TGGT, which provides midstream services to natural gas producers. TGGT's operations are principally designed to facilitate delivery of natural gas produced in the East Texas/North Louisiana region to markets. Revenues are primarily derived from sales of natural gas purchased for resale and fixed fees earned from gathering, treating and compression of natural gas. TGGT does not own any natural gas processing facilities.

Due to the rapid natural gas production growth in the Haynesville/Bossier shale, TGGT has increased its throughput dramatically in its core areas of operation within East Texas and North Louisiana. TGGT's primary customers are EXCO and BG Group. TGGT owns and operates TGG Pipeline, Ltd., or TGG, and Talco Midstream Assets, Ltd., or Talco. The assets of TGG include treating facilities and gathering pipelines that connect to downstream pipelines. Talco's assets primarily consist of gathering pipelines that provide well hookups and lateral connections. Current throughput totals approximately 1.2 Bcf per day.

In 2010, TGG completed a 27 mile, 36–inch diameter header for gathering natural gas from Haynesville/Bossier shale and Cotton Valley wells, principally in DeSoto Parish, Louisiana. TGG operates amine, glycol, and H2S facilities, which treat natural gas in order to meet pipeline quality specifications for downstream transportation. TGGT's system has access to 13 interstate and intrastate pipeline markets. TGG has approximately 126 miles of pipeline comprised of 12, 16, and 20-inch diameter pipe in its legacy East Texas area with a current throughput capacity of approximately 460 Mmcf per day. TGG continues to see growth in throughput in both its existing East Texas gathering system area as well as in its new shale-focused systems in the North Louisiana area.

Additionally, TGG has initiated major midstream expansion efforts in the Shelby Area in East Texas. Certain pipelines and facilities were completed in 2010 and upon completion in 2011, TGGT estimates it will operate approximately 72 miles of gathering systems. The current throughput capacity is approximately 190 Mmcf per day, and the throughput capacity is planned to increase to approximately 740 Mmcf per day by the third quarter of 2011. In addition, the gathering systems are expected to have treating capacity in excess of 500 Mmcf per day by year end 2011.

Through Talco, TGGT owns and operates a network of gas gathering systems comprised of over 800 miles of pipeline located in East Texas and North Louisiana. These gathering pipelines primarily service Cotton Valley production in East Texas/North Louisiana and Haynesville/Bossier production in North Louisiana. Approximately 200 miles of Talco's gathering lines are located in the core area of the Haynesville/Bossier shale in North Louisiana. Natural gas is gathered through fixed fee arrangements pursuant to which the fee income represents an agreed rate per unit of throughput. The revenues earned from these arrangements are directly related to the volume of natural gas that flows through the systems and are not directly dependent on commodity prices.

The increase in throughput across TGGT's operations has generated increases in operating cash flows in 2010. The projected drilling programs by producers targeting the Haynesville/Bossier shale areas of East Texas and North Louisiana are expected to generate continued growth for TGGT.

Our Appalachia midstream operations are jointly owned with BG Group. The near term focus is to maximize take-away from existing infrastructure and leverage the TGGT personnel and practices as the Marcellus shale region develops. The current plans, which are largely dependent on the results of the Appalachia

JV's development and appraisal drilling results, will likely be a combination of built facilities, joint ventures with third parties or outsourcing in certain areas.

Appalachia upstream operations

OPCO serves as the operator of our Appalachia producing and development operations and owns a 0.5% working interest in our Appalachia joint venture properties. EXCO and BG Group each own 50% of OPCO.

Other gas gathering systems

A gathering system and treating facility in the area of our Vernon Field operations, or Vernon Gathering, gathers and transports natural gas from our Vernon Field and, to a lesser extent, natural gas from third-party producers. The gathering system transports natural gas to our Caney Lake facility where the natural gas is treated and delivered to interstate pipeline systems. During 2010, average throughput in Vernon Gathering was approximately 100 Mmcf per day.

Our principal customers

For the year ended December 31, 2010, sales to BG Energy Merchants LLC and Louis Dreyfus Energy Services LP, accounted for approximately 21.5% and 10.1%, respectively, of total consolidated revenues. The loss of any significant customer may cause a temporary interruption in sales of, or lower price for, our oil and natural gas, but we believe that the loss of any one customer would not have a material adverse effect on our results of operations or financial condition.

Competition

The oil and natural gas industry is highly competitive, particularly with respect to capturing prospective oil and natural gas properties and oil and natural gas reserves. 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 headcount substantially larger than ours. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and natural gas reserves, but also have refining operations, market refined products, own drilling rigs, and generate electricity.

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. Depending on the region, we may experience difficulties in obtaining drilling rigs and other services in certain areas as well as an increase in the cost for these services and related material and equipment. We are unable to predict when, or if, such shortages may again occur or how such shortages and price increases will affect our development and exploitation program. Competition has also been strong in hiring experienced personnel, particularly in petroleum engineering, geoscience, accounting and financial reporting, tax and land professions. In addition, competition is strong for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights. We are often outbid by competitors in our attempts to acquire properties or companies. The oil and natural gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported liquefied natural gas. Competitive conditions may be affected by future legislation and regulations as the U.S. develops new energy and climate-related policies. All of these challenges could make it more difficult to execute our growth strategy and increase our costs.

Applicable laws and regulations

General

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, which could increase the regulatory burden and the potential for financial sanctions for noncompliance. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect others in our industry with similar types, quantities and locations of production.

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

Production regulation

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

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

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

Our Pennsylvania operations are subject to numerous stringent federal and state statutes and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing, storage and disposal of water used in the drilling and completion process, restrict or prohibit drilling activities in certain areas and on certain lands lying within wetlands and other protected areas, require closing earthen impoundments and impose liabilities for pollution resulting from operations or failure to comply with regulatory filings.

Statutes, rules and regulations affecting exploration and production undergo constant review and often are amended, expanded and reinterpreted, making the prediction of future costs or the impact of regulatory compliance to new laws and statute difficult. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability.

FERC matters

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

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

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

Federal, state or Indian oil and natural gas leases

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

Surface Damage Acts

In addition, eleven states and some tribal nations have enacted surface damage statutes ("SDAs"). These laws are designed to compensate for damage caused by mineral development. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain bonding requirements and specific expenses for exploration and activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

Other regulatory matters relating to our pipeline and gathering system assets

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

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

U.S. federal taxation

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

U.S. environmental regulations

The exploration, development and production of oil and natural gas, including the operation of saltwater injection and disposal wells, are subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, installing and operating oil and natural gas wells. Federal environmental statutes to which our domestic activities are subject include, but are not limited to:

- the Oil Pollution Act of 1990, or OPA;
- the Clean Water Act, or CWA;
- Rivers and Harbors Act of 1899;
- 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 subject to regulations promulgated under these statutes and comparable state statutes. We also are subject to regulations governing the handling, transportation, storage and disposal of naturally occurring radioactive materials that are found in our oil and natural gas operations. Administrative, civil and criminal 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 we undertake certain activities, limit or prohibit other activities because of protected areas or species, impose certain substantial liabilities for the clean-up of pollution, impose certain reporting requirements, regulate remedial plugging operations to prevent future contamination, and 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 the 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) specified damages, such as loss of use, property damage and natural resource damages. The scope 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 into waters of the United States, including certain wetlands, of dredged materials, which may apply to various of our construction activities, as well as requirements to develop Spill Prevention Control and Countermeasure Plans and Facility Response Plans to address potential discharges of oil into or upon waters of the United States and adjoining shorelines. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters.

CERCLA, as amended, often referred to as Superfund, and comparable state Superfund statutes, impose liability that is generally joint and several and that is retroactive 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" or under state law, other specified substances, into the environment. 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 Environmental Protection Agency, or EPA, and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the cost of such action. Liability can arise from conditions on properties where operations are conducted, even under circumstances where such operations were performed by third parties not under our control, and/or from conditions at third party disposal facilities where wastes from operations were sent. Although CERCLA currently exempts petroleum (including oil, natural gas and NGLs) from the definition of hazardous substance, some similar state statutes do not provide such an exemption. We also cannot assure you that this exemption will be preserved in any future amendments of the act. Such amendments could have a material impact on our costs or operations. Additionally, our operations may involve the use or handling of other materials that may be classified as hazardous substances under CERCLA or regulated under similar state statutes. We may also be the owner or operator of sites on which hazardous substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA. We also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. In the event hazardous substance contamination is discovered at a site on which we are or have been an owner or operator, we could be liable for costs of investigation and remediation and natural resource damages.

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.

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, in addition to 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 non-hazardous solid waste in our routine operations. It is possible that certain wastes generated by our operations, which are currently exempt from "hazardous waste" regulations under RCRA, may in the future be designated as "hazardous waste" under RCRA or other applicable state statutes and become subject to more rigorous and costly management and disposal requirements.

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

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

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

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

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

We are also unable to assure you that more stringent laws and regulations protecting the environment will not be adopted and that we will not incur material expenses in complying with them in the future. For example, although federal legislation regarding the control of emissions of greenhouse gases or GHGs, for the present, appears unlikely, EPA has been implementing regulatory measures under existing CAA authority and some of those regulations may affect our operations. GHGs are certain gases, including carbon dioxide, a product of the combustion of natural gas, and methane, a primary component of natural gas, that may be contributing to warming of the Earth’s atmosphere resulting in climatic changes. These GHG regulations could require us to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas we produce.

On June 3, 2010, EPA published its so-called GHG tailoring rule that will phase in federal prevention of significant deterioration (PSD) and Title V operating permit requirements for new sources and modifications with the potential to emit specific quantities of GHGs. Those permitting provisions, when they become applicable to our operations, could require controls or other measures to reduce GHG emissions from new or modified sources, and we could incur additional costs to satisfy those requirements. On November 30, 2010, EPA published a rule establishing GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions, with the first annual report—for 2010—being due in March of 2011. Although this rule does not limit the amount of

GHGs that can be emitted, it could require us to incur costs to monitor, recordkeep and report GHG emissions associated with our operations.

Many of the company's exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of several chemical additives—as well as sand and other proppants into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well.

In addition, Congress has periodically considered legislation to amend the federal Safe Drinking Water Act to remove the exemption enjoyed by hydraulic fracturing operations and to require reporting and disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. These bills, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing and increasing our costs of compliance.

In addition, state, local and river basin conservancy districts have all previously exercised their various regulatory powers to curtail and, in some cases, place moratoriums on hydraulic fracturing. State regulations include express inclusion of hydraulic fracturing into existing regulations covering other aspects of exploration and production and specifically may include, but not be limited to, the following:

- requirement that logs and pressure test results are included in disclosures to state authorities
- disclosure of hydraulic fracturing fluids, chemicals, proppants and the ratios of same used in operations
- specific disposal regimens for hydraulic fracturing fluid
- replacement/remediation of contaminated water assets
- minimum depth of hydraulic fracturing

Local regulations, which may by preempted by state and federal regulations, have included the following which, while prompted by hydraulic fracturing, may extend to all operations:

- noise control ordinances
- traffic control ordinances
- limitations on the hours of operations
- mandatory reporting of accidents, spills and pressure test failures

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 agreement.

Operational Factors

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. In the event of exploration failures, environmental damage, or other accidents such as well fires, blowouts, equipment failure, human error, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties. As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our operating results, financial position or cash flows. For further discussion on risks see Item 1A. *Risk Factors*.

Our employees

As of December 31, 2010, we employed 927 persons. 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 and contractors.

Forward-looking statements

This Annual Report on Form 10-K contains forward-looking statements, as defined in Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. These forward-looking statements relate to, among other things, the following:

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

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

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

- fluctuations in prices of oil and natural gas;
- imports of foreign oil and natural gas, including liquefied natural gas;
- future capital requirements and availability of financing;
- continued disruption of credit and capital markets and the ability of financial institutions to honor their commitments, such as the events which occurred during the third quarter of 2008 and thereafter, for an extended period of time;
- estimates of reserves and economic assumptions used in connection with our acquisitions;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- exploratory risks, including our Marcellus shale play in Appalachia and the Haynesville/Bossier shale play in East Texas/North Louisiana;
- 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;
- title to our properties;
- litigation;
- competition;
- general economic conditions, including costs associated with drilling and operations of our properties;
- environmental or other governmental regulations, including legislation to reduce emissions of greenhouse gases, legislation of derivative financial instruments, regulation of hydraulic fracture stimulation and elimination of income tax incentives available to our industry;
- receipt and collectability of amounts owed to us by purchasers of our production and counterparties to our derivative financial instruments;
- decisions whether or not to enter into derivative financial instruments;
- potential acts of terrorism;
- actions of third party co-owners of interests in properties in which we also own an interest;
- risks associated with the proposal by Mr. Miller to acquire our common stock;
- fluctuations in interest rates; and
- our ability to effectively integrate companies and properties that we acquire.

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

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

Glossary of selected oil and natural gas terms

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

2-D seismic. Geophysical data that depict the subsurface strata in two dimensions

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.

Appraisal wells. Wells drilled to convert an area or sub-region from the resource to the reserves category

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.

Deterministic estimate. The method of estimating reserves or resources when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

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

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

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

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

Economically producible. As it relates to a resource, a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

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

Exploratory Well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or 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.

Fracture Stimulation. A stimulation treatment routinely performed involving the injection of water, sand and chemicals under pressure to stimulate hydrocarbon production in low-permeability reservoirs.

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.

Held-by-production. A provision in an oil, gas and mineral lease that perpetuates a company's right to operate a property or concession as long as the property or concession produces a minimum paying quantity of oil or gas.

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.

Initial production rate. Generally, the maximum 24 hour production volume from a well.

Mbbl. One thousand stock tank barrels.

Mcf. One thousand cubic feet of natural gas.

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

Mmbbl. One million stock tank barrels.

Mmbtu. One million British thermal units.

Mmcf. One million cubic feet of natural gas.

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

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

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

Mmmbtu. One billion British thermal units.

Net Acres or Net Wells. The sum of the fractional working interests owned in gross acres or gross wells.

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.

Pad drilling. The drilling of multiple wells from the same site.

Play. A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

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 future 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 and natural gas prices and operating and capital 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.

Probabilistic estimate. The method of estimation of reserves or resources when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

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

Proved Developed Reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate.

Proved Reserves. Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved Undeveloped Reserves. Reserves of any category 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 directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Under no circumstances shall estimates for 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 projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

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.

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

Reserve Life. The estimated productive life, in years, of a proved reservoir based upon the economic limit of such reservoir producing hydrocarbons in paying quantities assuming certain price and cost parameters. For purposes of this Annual Report on Form 10-K, reserve life is calculated by dividing the Proved Reserves (on an Mmcfe basis) at the end of the period by production volumes for 2010.

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

Resources. All quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. It also includes all types of petroleum whether currently considered "conventional" or "unconventional."

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.

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

Spud. To start the well drilling process.

Standardized Measure of discounted future net cash flows or the Standardized Measure. Under the Standardized Measure, future cash flows for the years ended December 31, 2010 and 2009 are estimated by applying the simple average spot prices for the trailing twelve month period using the first day of each month beginning on January 1 and ending on December 1 of each respective year, adjusted for fixed and determinable escalations, to the estimated future production of year-end Proved Reserves. Spot prices used to compute estimated future cash flows for the year ended December 31, 2008 are based on year-end spot prices for such year. Future cash inflows are reduced by estimated future production and development costs based on period-end and future plugging and abandonment costs to determine pre-tax cash inflows. Future income taxes are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the associated properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate to arrive at the Standardized Measure.

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

Tcf. One trillion cubic feet of natural gas.

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

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

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

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

Available information

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

ITEM 1A. RISK FACTORS

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

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

Risks relating to our business

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

Our future financial condition, access to capital, cash flow and results of operations depend upon the prices we receive for our oil and natural gas. We are particularly dependent on prices for natural gas. As of December 31, 2010, 97.1% 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, natural gas and refined products;
- concerns about global warming or other conservation initiatives and the extent of governmental price controls and regulation of production;
- weather;
- foreign and domestic government relations; and
- overall economic conditions.

In the past, prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue. During 2010, the NYMEX price for natural gas has fluctuated from a high of $6.01 per Mmbtu to a low of $3.29 per Mmbtu, while the NYMEX West Texas Intermediate crude oil price ranged from a high of $91.51 per Bbl to a low of $68.01 per Bbl. For the five years ended December 31, 2010, the NYMEX Henry Hub natural gas price ranged from a high of $15.38 per Mmbtu to a low of $2.51 per Mmbtu, while the NYMEX West Texas Intermediate crude oil price ranged from a high of $145.29 per Bbl to a low of $33.87 per Bbl. On December 31, 2010, the spot market price for natural gas at Henry Hub was $4.16 per Mmbtu, a 28.2% decrease from December 31, 2009. On December 31, 2010, the spot market price for crude oil at Cushing was $89.84 per Bbl, a 13.2% increase from December 31, 2009. In 2010, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were $76.18 per Bbl and $4.29 per Mcf compared with 2009 average realized prices of $53.72 per Bbl and $3.93 per Mcf, respectively.

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

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

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

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 and other 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, obtaining fracture stimulation crews and materials, and increasing costs to drill wells. All of these risks could adversely affect our results of operations and financial condition.

Part of our strategy involves acquiring acreage and drilling in new or emerging shale resource plays. As a result, our drilling results in these areas are subject to more uncertainties than our drilling program in the more established shallower formations and may not meet our expectations for reserves or production.

The results of our drilling in new or emerging shale resource plays, such as the Haynesville/Bossier shale and the Marcellus shale, may be more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are less able to use past drilling results in those areas to help predict our future drilling results. In addition, part of our drilling strategy to maximize recoveries from the shale resource plays involves the drilling of horizontal wells using completion techniques that have proven to be successful in other shale formations. Our experience with horizontal drilling of the Haynesville/Bossier shale and the Marcellus shale to date, as well as the industry's drilling and production history in these formations, is limited. In the past, we acquired producing oil and natural gas properties with established production histories which generated cash flow immediately upon closing the acquisition. Since we shifted our acquisition strategy to focus on acreage acquisitions in shale areas with Haynesville/Bossier and Marcellus potential, we now invest significant capital for acreage generally without any meaningful production or immediate cash flow. We must then incur significant additional costs to drill and properly develop the acreage we acquire in these shale areas. We may use bank debt to fund these acquisitions but we do not receive credit for borrowing base purposes until we drill wells and generate production.

Increased drilling in the shale formations may cause pipeline and gathering system capacity constraints that may limit our ability to sell natural gas and/or receive market prices for our gas.

The Haynesville/Bossier shale wells we have drilled to date have reported very high initial production rates, implying potentially large reserves. If drilling in the Haynesville/Bossier shale continues to be successful, the amount of natural gas being produced in the area from these new wells, as well as natural gas produced from other existing wells, may exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available. If this occurs it will be necessary for new interstate and intrastate pipelines and gathering systems to be built. While development in the Marcellus shale is in its early stages, the geography in the Appalachia area will present similar, if not greater, gathering system challenges.

Because of the current economic climate, certain planned pipeline projects for the Haynesville/Bossier and Marcellus shale areas may not occur because the prospective owners of these pipelines may be unable to secure the necessary financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our natural gas to interstate pipelines. In such event, this could result in wells being shut in awaiting a pipeline connection or capacity and/or natural gas being sold at much lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations.

We conduct a substantial portion of our operations through joint ventures, and our failure to continue such joint ventures or resolve any material disagreements with our partners could have a material adverse effect on the success of these operations, our financial condition and our results of operations.

We conduct a substantial portion of our operations through joint ventures with third parties, principally BG Group, and as a result, the continuation of such joint ventures is vital to our continued success. We may also enter into other joint venture arrangements in the future. In many instances we depend on these third parties for elements of these arrangements that are important to the success of the joint venture, such as agreed payments of substantial carried costs pertaining to the joint venture and their share of capital and other costs of the joint venture. The performance of these third party obligations or the ability of third parties to meet their obligations under these arrangements is outside our control. If these parties do not meet or satisfy their obligations under these arrangements, the performance and success of these arrangements, and their value to us, may be adversely affected. If our current or future joint venture partners are unable to meet their obligations, we may be forced to undertake the obligations ourselves and/or incur additional expenses in order to have some other party perform such obligations. In such cases we may also be required to enforce our rights, which may cause disputes among our joint venture parties and us. If any of these events occur, they may adversely impact us, our financial performance and results of operations, these joint ventures and/or our ability to enter into future joint ventures. In addition, BG Group has the right to elect to participate in all acreage and other acquisitions in defined areas of mutual interest. If they elect not to participate in a particular transaction or transactions, we would bear the entire cost of the acquisition and all development costs of the acquired properties.

Such joint venture arrangements may involve risks not otherwise present when exploring and developing properties directly, including, for example:

- our joint venture partners may share certain approval rights over major decisions;
- the possibility that our joint venture partners might become insolvent or bankrupt, leaving us liable for their shares of joint venture liabilities;
- the possibility that we may incur liabilities as a result of an action taken by our joint venture partners;
- joint venture partners may be in a position to take action contrary to our instructions or requests or contrary to our policies or objectives;
- disputes between us and our joint venture partners may result in litigation or arbitration that would increase our expenses, delay or terminate projects and prevent our officers and directors from focusing their time and effort on our business;
- that under certain joint venture arrangements, neither joint venture partner may have the power to control the venture, and an impasse could be reached which might have a negative influence on the joint venture; and
- our partners may decide to terminate their relationship with us in any joint venture company or sell its interest in any of these companies and we may be unable to replace such partner or raise the necessary financing to purchase such partner’s interest.

The failure to continue some of our joint ventures or to resolve disagreements with our partners could adversely affect our ability to transact the business that is the subject of such joint venture, which would in turn negatively affect our financial condition and results of operations.

Our joint ventures with BG Group contemplate that we will make significant capital expenditures and subject us to certain legal and financial terms that could adversely affect us.

On August 14, 2009 we closed two joint venture transactions with BG Group, which involved the sale of an undivided 50% interest in an area of mutual interest in certain oil and natural gas properties in East Texas and North Louisiana and a 50% interest in certain midstream operations. The upstream transaction operates as a joint venture pursuant to a joint development agreement under which EXCO acts as the operator. The midstream transaction functions as a 50-50 joint venture between EXCO and BG Group, with neither party having control over the management of, or a controlling beneficial economic interest in, the operations.

On June 1, 2010, we closed our Appalachian joint venture with BG Group. Pursuant to the agreements governing the joint venture, EXCO and BG Group agreed to jointly explore and develop their Appalachian properties, particularly the Marcellus shale. EXCO and BG Group each own a 50% interest in OPCO which operates the properties, subject to oversight from a management board having equal representation from EXCO and BG Group. In addition, certain midstream assets owned by EXCO were transferred to a newly formed, jointly owned entity, Appalachia Midstream, LLC, through which EXCO and BG Group will pursue the construction and expansion of gathering systems, pipeline systems and treating facilities for anticipated future production from the Marcellus shale.

Each of these joint ventures may require us to make significant capital expenditures. If we do not timely meet our financial commitments under the respective joint venture agreements, our rights to participate in such joint ventures will be adversely affected and other parties to the joint ventures may have a right to acquire a share of our interest in such joint ventures proportionate to, and in satisfaction of, our unmet financial obligations.

EXCO has unconditionally guaranteed its subsidiaries' performance of the joint venture agreements under the Appalachia joint ventures.

Our use of derivative financial instruments is subject to risks that our counterparties may default on their contractual obligations to us and may cause us to forego additional future profits or result in our making cash payments.

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

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

Our use of derivative financial instruments could have the effect of reducing our revenues and the value of our common stock. During the year ended December 31, 2010 and 2009, we received cash payments to settle our derivative financial instrument contracts totaling $217.5 million and $478.5 million, respectively. For the year ended December 31, 2010, 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 $59.5 million. As of December 31, 2010, the net unrealized gains on our oil and natural gas derivative financial instrument contracts were $88.9 million. The ultimate settlement amount of these unrealized derivative financial instrument contracts is dependent on future commodity prices. In connection with acquisitions which included producing properties, we have, in certain instances, assumed derivative financial instruments covering a significant portion of estimated future production. We may incur significant unrealized losses in the future from our use of derivative financial instruments to the extent market prices increase and our derivatives contracts remain in place. See "—Item 7. Management's discussion and analysis of financial condition and results of operations—Our results of operations—Derivative financial instruments."

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

As of December 31, 2010, our consolidated indebtedness was approximately $1.6 billion, an increase from our December 31, 2009 consolidated debt of approximately $1.2 billion, primarily the result of borrowings to fund the Common Transaction, the Southwestern Transaction, the Chief Transaction and capital contributions to TGGT. Proceeds received from our Appalachia JV and other reimbursements from BG Group partially offset these borrowings. While we believe our consolidated debt is manageable, our reserves, borrowing base, production and cash flows were reduced as a result of our divestitures and joint venture transactions. 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. In addition, we expect to fund additional acquisitions with debt, which may increase our outstanding debt without any corresponding borrowing base increases. If our operating cash flow and other 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. These remedies may not be available on commercially reasonable terms, or at all. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt under our credit agreement and the indenture governing our 2018 Notes, or the Indenture, which could cause us to default on our obligations and could impair our liquidity.

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

Our success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are profitable to produce. Factors that may hinder our ability to acquire or develop 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, and any indemnifications we receive from sellers may be insufficient to protect us from such risks, which may result in unexpected liabilities and costs to us.

Generally, it is not feasible for us to review in detail every individual property involved in an acquisition. Our business strategy focuses on acquisitions of producing oil and natural gas properties. Any future acquisitions will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards, potential tax and Employee Retirement Security Act, or ERISA, liabilities, and other liabilities and other similar factors. Ordinarily, our review efforts are focused on the higher-valued properties. 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.

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

The growth of our business will require substantial capital on a continuing basis. Due to the amount of debt we have incurred, it may be difficult for us in the foreseeable future to obtain additional debt financing 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, be unable to implement our growth strategy.

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.

Section 404 of the Sarbanes-Oxley Act of 2002 requires companies subject to the act to disclose any material weaknesses discovered through management's assessments. We are required to comply with Section 404 of the Sarbanes-Oxley Act of 2002. Prior to December 31, 2007, we were not required to make an assessment of the effectiveness of our internal control over financial reporting for that purpose.

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

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

Any material weaknesses or other deficiencies in our internal control over financial reporting may affect our ability to comply with SEC reporting requirements and the 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 our company or increased transaction volume, or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

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

Our ability to market our oil and natural gas production will depend upon the availability and capacity of natural gas gathering systems, pipelines and other transportation facilities. We are primarily dependent upon third parties to transport our products. Transportation space on the gathering systems and pipelines we utilize is occasionally limited or unavailable due to repairs, outages caused by accidents or other events, or improvements to facilities or due to space being utilized by other companies that have priority transportation agreements. We experienced production curtailments in East Texas/North Louisiana during 2009 and 2010 and in the Appalachian Basin during 2008, 2009 and 2010 resulting from capacity restraints and short term shutdowns of certain pipelines for maintenance purposes. As we have increased our knowledge of the Haynesville/Bossier reservoirs, we have begun to shut in production on adjacent wells when conducting completion operations. Due to the high production capabilities of these wells, these volumes can be significant. 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.

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

Our future success will depend on the success of our acquisition, exploration, development and exploitation activities. Our decisions to purchase, explore, 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, 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, 2010, third parties operate wells that represent approximately 3.2% of our proved developed producing 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, our financial condition and the value of our common stock.

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

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

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

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

We have in the past experienced some of these events during our drilling, production and midstream 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. We do not carry business interruption insurance. Losses and liabilities arising from uninsured or under-insured events could require us to make large unbudgeted cash expenditures that could adversely impact our results of operations and cash flow.

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

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

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, production and sale of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition and results of operations. Please see "Item 1. Business—Applicable laws and regulations" for a description of the laws and regulations that affect us.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

President Obama's proposed Fiscal Year 2011 and Fiscal Year 2012 Budgets included proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the manufacturing deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

EPA's implementation of climate change regulations could result in increased operating costs and reduced demand for the oil and natural gas we produce.

Although federal legislation regarding the control of emissions of greenhouse gases or GHGs, for the present, appears unlikely, EPA has been implementing regulatory measures under existing CAA authority and some of those regulations may affect our operations. GHGs are certain gases, including carbon dioxide, a product of the combustion of natural gas, and methane, a primary component of natural gas, that may be contributing to warming of the Earth's atmosphere resulting in climatic changes. These GHG regulations could require us to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas we produce.

On June 3, 2010, EPA published its so-called GHG tailoring rule that will phase in federal prevention of significant deterioration (PSD) permit requirements for new sources and modifications, and Title V operating permits for all sources, that have the potential to emit specific quantities of GHGs. Those permitting provisions, when they become applicable to our operations, could require controls or other measures to reduce GHG emissions from new or modified sources, and we could incur additional costs to satisfy those requirements. On November 30, 2010, EPA published a rule establishing GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions, with the first annual report—for 2010—being due in March of 2011. Although this rule does not limit the amount of GHGs that can be emitted, it could require us to incur costs to monitor, recordkeep and report GHG emissions associated with our operations.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, that, among other provisions, establishes federal oversight and regulation of the over-the-counter (OTC) derivatives market and entities that participate in that market. The new legislation requires the Commodities Futures Trading Commission, or the CFTC, and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment that will clarify the Dodd-Frank Act and its exceptions. Under the Dodd-Frank Act legislation, OTC derivative dealers and other major OTC derivative market participants could be subjected to substantial supervision and regulation. The legislation expands the power of the CFTC to regulate derivative transactions related to energy commodities, including oil and natural gas, to mandate clearance of derivative contracts through registered derivative clearing organizations, and to impose conservative capital and margin requirements and strong business conduct standards on OTC derivative transactions. The CFTC has proposed regulations that would implement speculative limits on trading and positions in certain commodities. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or the CFTC may issue new regulations, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity. The full effects of the Dodd-Frank Act will not be known until it is implemented through regulations and the market for these hedges has adjusted. It is possible the hedges will become more expensive, uneconomic or unavailable, which could lead to increased costs or commodity price volatility or a combination of both.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to remove the exemption for hydraulic fracturing operations and require reporting and disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Sponsors of bills before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Such bills, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing and increasing our costs of compliance.

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, for example, the regulation of GHG emissions under new federal legislation, the federal Clean Air Act, or state or regional regulatory programs. Regulation of GHG emissions by Congress, EPA, or various states in the United States in areas in which we conduct business could have an adverse effect on our operations and demand for the oil and natural gas that we produce.

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

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

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

We follow the full cost method of accounting for our oil and natural gas properties. Depending upon oil and natural gas prices in the future, and at the end of each quarterly and annual period when we are required to test the carrying value of our assets using full cost accounting rules, we may be required to write-down the value of our oil and natural gas properties if the present value of the after-tax future cash flows from our oil and natural gas properties falls below the net book value of these properties. We have in the past, including 2008 and the first quarter of 2009, experienced ceiling test write-downs with respect to our oil and natural gas properties. Future non-cash ceiling test write-downs could negatively affect our results of operations and net worth.

We also test goodwill for impairment annually or when circumstances indicate that an impairment may exist. If the book value of our reporting units exceeds the estimated fair value of those reporting units, an impairment charge will occur, which would negatively impact our results of operations and 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, it has become more difficult to maintain and grow a customer base of creditworthy customers because 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. As a result, we may experience a material loss as a result of the failure of our customers to pay us for prior purchases of our oil or natural gas.

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

For the year ended December 31, 2010, sales to BG Energy Merchants LLC and Louis Dreyfus Energy Services LP accounted for approximately 21.5% and 10.1%, respectively, of total consolidated revenues. BG Energy Merchants LLC is a subsidiary of BG Group. For the year ended 2009, there were no sales to any individual customer which exceeded 10% of our consolidated revenues or were considered material to our operations. We continue to sell substantial quantities of natural gas to these customers. As our volumes in the Haynesville shale grow, BG Energy Merchants LLC and others are expected to become more significant. The loss of any significant customer may cause a temporary interruption in sales of, or a lower price for, our oil and natural gas.

We have entered into significant natural gas firm transportation contracts primarily in East Texas and North Louisiana which require us to pay fixed amounts of money to the shippers regardless of quantities actually shipped. If we are unable to deliver the necessary quantities of natural gas to the shippers, our results of operations and liquidity could be adversely affected.

As of December 31, 2010, we were contractually committed to spend approximately $888.1 million over the next ten years for firm transportation services. We may enter into additional firm transportation agreements as our development of our Haynesville, Bossier and Marcellus shale plays expand. We expect our production volumes, as well as our competitors, to increase significantly in the Haynesville and Marcellus shale areas. The use of firm transportation allows us priority space in a shippers' pipeline which we believe is a strategic advantage. In the event we encounter delays due to construction, interruptions of operations or delays in connecting new volumes to gathering systems or pipelines for an extended period of time, the requirements to pay for quantities not delivered could have a material impact on our results of operations and liquidity.

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

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

We depend upon third party pipelines and other facilities that provide delivery options from our transportation and gathering pipelines for the benefit of our customers. Much of the natural gas transported by our pipelines must be treated or processed before delivery into a pipeline for natural gas. If the processing and treating 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 exist in a litigious environment

Any constituent could bring suit regarding our existing or planned operations or allege a violation of an existing contract. Any such action could delay when planned operations can actually commence or could cause a halt to existing production until such alleged violations are resolved by the courts. Not only could we incur significant legal and support expenses in defending our rights, but halting existing production or delaying planned operations could impact our future operations and financial condition. In addition, we are defendants in numerous cases involving claims by landowners for surface or subsurface damages arising from our operations and for claims by unleased mineral owners and royalty owners for unpaid or underpaid revenues customary in our business. We incur costs in defending these claims and from time to time must pay damages or other amounts due. Such legal disputes can also distract management and other personnel from their primary responsibilities.

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 February 17, 2011, we had approximately $1.3 billion of indebtedness, including $549.0 million of indebtedness subject to variable interest rates and $750.0 million of the 2018 Notes. Our total interest expense, excluding amortization of deferred financing costs, on an annual basis based on current available interest rates would be approximately $71.4 million and would change by approximately $5.5 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 our credit agreement, the Indenture 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 and may be required to surrender assets pursuant to the security provisions of our credit agreement. Further, failing to comply with the financial and other restrictive covenants in our credit agreement and the Indenture 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 exploration, exploitation, development, acquisitions of undeveloped acreage and production 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. Significant additions of undeveloped acreage financed with debt may result in increased indebtedness without any corresponding increase in borrowing base, which could curtail drilling and development of this acreage or could cause us to not comply with our debt covenants.

To service our indebtedness and fund our planned capital expenditure programs, 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 2018 Notes and loans under the EXCO Resources Credit Agreement, and to fund planned capital expenditures will depend on our ability to generate cash from operations and other resources 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 2018 Notes and loans under the EXCO Resources Credit Agreement, or to fund our other liquidity needs. If our cash flow and capital resources are insufficient to fund our debt obligations and capital expenditure programs, we may be forced to sell assets, seek additional equity or debt capital or restructure our debt. These remedies may not be available 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.

For 2011, we have planned capital expenditures which exceed our planned cash flows from operations. Accordingly, our reliance on available borrowing capacity under the EXCO Resources Credit Agreement and remaining in compliance with debt covenants is critical.

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

Risks relating to our common stock

There can be no assurance that any definitive offer will be made with respect to the proposal made by Douglas H. Miller, our Chairman and Chief Executive Officer, to acquire all of our common stock, that any agreement will be executed or that this or any other transaction will be approved or completed. The absence of a proposal to acquire our common stock may have an adverse effect on the market price of our common stock.

On October 29, 2010, our Chairman and Chief Executive Officer, Douglas H. Miller, presented a letter to our board of directors indicating an interest in acquiring all of the outstanding shares of our stock not already owned by Mr. Miller for a cash purchase price of $20.50 per share. We have cautioned our shareholders and others considering trading in our securities that our Board has only received the proposal and that no decisions have been made by the Board or the special committee with respect to our response to the proposal. The proposal submitted was not a definitive offer, and there is no assurance that a definitive offer will be made or accepted, that any agreement will be executed or that any transaction will be consummated. On the last trading day prior to the announcement of the proposal, our common stock closed at $14.80 per share. After the announcement, the trading price of our common stock has risen to trade closer to the $20.50 proposal price. If this proposal were rejected or withdrawn, and if no similar transaction presented itself, the stock price may fall below its current trading range.

Our stock price may fluctuate significantly.

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

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

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

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

As of December 31, 2010, we had 213,197,045 shares of common stock outstanding. All shares are freely tradable by persons other than our affiliates. Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline. In addition, the sale of these shares could impair our ability to raise capital through the sale of additional common or preferred stock.

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

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

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

Our articles of incorporation permit our board to issue up to 10,000,000 shares of preferred stock and to establish by resolution one or more series of preferred stock and the powers, designations, preferences and participating, optional or other special rights of each series of preferred stock. The preferred stock may be issued on terms that are unfavorable to the holders of our common stock, including the grant of superior voting rights, the grant of preferences in favor of preferred shareholders in the payment of dividends and upon our liquidation and the designation of conversion rights that entitle holders of our preferred stock to convert their shares into our common stock on terms that are dilutive to holders of our common stock. The issuance of preferred stock in future offerings may make a takeover or change in control of us more difficult.

We may reduce or discontinue paying our quarterly cash dividend if our board of directors determines that paying a dividend is no longer appropriate.

In October 2009, we commenced a quarterly cash dividend program on shares of our common stock. Any future dividend payments will depend on our earnings, capital requirements, financial condition, prospects and other factors that our board of directors may deem relevant. At any time, our board of directors may decide to reduce or discontinue paying our quarterly cash dividend. If we do not pay dividends, our common stock may be less valuable because a return on your investment will only occur if our stock price appreciates. In addition, our credit agreement and the Indenture restrict our ability to pay dividends.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Corporate offices

We lease office space in Dallas, Texas; Cranberry Township, Pennsylvania and Warrendale, Pennsylvania. We also have small offices for technical and field operations in Texas, Louisiana, Pennsylvania and West Virginia. The table below summarizes our material corporate leases.

Location	Approximate square footage	Approximate monthly payment	Expiration
Dallas, Texas	203,000	$283,000	December 31, 2015
Warrendale, Pennsylvania	56,000	$102,700	October 31, 2016
Cranberry Township, Pennsylvania	22,400	$ 29,000	February 28, 2013
The Woodlands, Texas	13,800	$ 28,700	June 30, 2012

Other

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

ITEM 3. LEGAL PROCEEDINGS

In the ordinary course of business, we are periodically a party to lawsuits and claims. We do not believe that any resulting liability from existing legal proceedings, individually or in the aggregate, will have a material adverse effect on our results of operations or financial condition. See "Note 19. Acquisition Proposal" of the notes to our consolidated financial statements for information regarding certain lawsuits against the Company or members of the board of directors in connection with Mr. Miller's acquisition proposal.

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

Not applicable.

PART II

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

Market information for our common stock

Our common stock trades 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:

	Price Per Share		Dividends declared
	High	Low	
2010			
First Quarter	$22.45	$16.50	$0.03
Second Quarter	21.34	14.02	0.03
Third Quarter	15.81	13.25	0.04
Fourth Quarter	20.37	13.62	0.04
2009			
First Quarter	$12.52	$ 7.68	$ —
Second Quarter	16.66	9.28	—
Third Quarter	19.38	10.57	—
Fourth Quarter(1)	22.52	14.91	0.05

(1) During the fourth quarter 2009, we paid two dividends of $0.025 per share.

Our shareholders

According to our transfer agent, Continental Stock Transfer & Trust Company, there were approximately 62 holders of record of our common stock on December 31, 2010 (including nominee holders such as banks and brokerage firms who hold shares for beneficial holders).

Our dividend policy

On October 1, 2009 our Board of Directors approved the commencement of a dividend program, and in 2009 we paid two quarterly cash dividends of $0.025 per share of EXCO's common stock. In 2010, we paid dividends of $0.03 per share in the first two quarters and $0.04 per share in the last two quarters of 2010. Our fourth quarter 2010 dividend of $0.04 per share was declared on November 18, 2010 and paid on December 15, 2010 to holders of record on November 30, 2010. Any future declaration of dividends, as well as the establishment of record and payment dates, is subject to the approval of EXCO's Board of Directors.

Issuer repurchases of common stock

The following table details our repurchase of common stock for the three months ended December 31, 2010:

Period	Total Number of Shares Purchased(1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(1)
October 1—October 31, 2010	0	$0.00	0	$192.5 million
November 1—November 30, 2010	0	$0.00	0	$192.5 million
December 1—December 31, 2010	0	$0.00	0	$192.5 million
Total	0	$0.00	0	

(1) On July 19, 2010, we announced a $200.0 million share repurchase program. We are not presently pursuing any repurchases pending strategic alternatives being evaluated by a special committee of our Board of Directors in connection with a proposal from our Chairman and Chief Executive Officer to purchase all of our outstanding common stock which he does not already own.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents our selected historical financial and operating data. You should read this financial data in conjunction with "Item 7. Management's discussion and analysis of financial condition and results of operations," our consolidated financial statements, the notes to our consolidated financial statements and the other financial information included in this Annual Report on Form 10-K. This information does not replace the consolidated financial statements.

Selected consolidated financial and operating data

	Year ended December 31,				
(in thousands, except per share amounts)	**2010**	**2009**	**2008**	**2007**	**2006**
Statement of operations data(1):					
Revenues:					
Oil and natural gas	$ 515,226	$ 550,505	$ 1,404,826	$ 875,787	$359,235
Midstream(2)	—	35,330	85,432	18,817	8,139
Total revenues	515,226	585,835	1,490,258	894,604	367,374
Costs and expenses:					
Oil and natural gas production(3)	108,184	177,629	238,071	168,999	68,517
Midstream operating(2)	—	35,580	82,797	16,289	7,797
Gathering and transportation	54,877	18,960	14,206	10,210	1,615
Depreciation, depletion and amortization	196,963	221,438	460,314	375,420	135,722
Write-down of oil and natural gas properties	—	1,293,579	2,815,835	—	—
Accretion of discount on asset retirement obligations	3,758	7,132	6,703	4,878	2,014
General and administrative(4)	105,114	99,177	87,568	64,670	41,206
Gain on divestitures and other operating items	(509,872)	(676,434)	(2,692)	(3,997)	—
Total costs and expenses	(40,976)	1,177,061	3,702,802	636,469	256,871
Operating income (loss)	556,202	(591,226)	(2,212,544)	258,135	110,503
Other income (expense):					
Interest expense	(45,533)	(147,161)	(161,638)	(181,350)	(84,871)
Gain on derivative financial instruments(5)	146,516	232,025	384,389	26,807	198,664
Equity method income (loss)	16,022	(69)	—	—	1,593
Other income	327	126	1,289	6,160	2,466
Total other income (expense)	117,332	84,921	224,040	(148,383)	117,852
Income (loss) before income taxes	673,534	(506,305)	(1,988,504)	109,752	228,355
Income tax expense (benefit)	1,608	(9,501)	(255,033)	60,096	89,401
Net income (loss)	671,926	(496,804)	(1,733,471)	49,656	138,954
Preferred stock dividends	—	—	(76,997)	(132,968)	—
Net income (loss) available to common shareholders	$ 671,926	$ (496,804)	$(1,810,468)	$ (83,312)	$138,954
Basic income (loss) per share available to common shareholder	$ 3.16	$ (2.35)	$ (11.81)	$ (0.80)	$ 1.44
Diluted income (loss) per share available to common shareholders	$ 3.11	$ (2.35)	$ (11.81)	$ (0.80)	$ 1.41
Weighted average common and common equivalent shares outstanding:					
Basic	212,465	211,266	153,346	104,364	96,727
Diluted	215,735	211,266	153,346	104,364	98,453

Selected consolidated financial and operating data (continued)

	Year ended December 31,				
	2010	2009	2008	2007	2006
Statement of cash flow data:					
Net cash provided by (used in):					
Operating activities	$ 339,921	$ 433,605	$ 974,966	$ 577,829	$ 227,659
Investing activities	(712,854)	1,235,275	(1,708,579)	(2,396,437)	(1,791,517)
Financing activities	348,755	(1,657,612)	735,242	1,851,296	1,359,727
Balance sheet data:					
Current assets	$ 520,460	$ 402,088	$ 513,040	$ 311,300	$ 236,710
Total assets	3,477,420	2,358,894	4,822,352	5,955,771	3,707,057
Current liabilities	285,698	212,914	322,873	278,167	190,924
Long-term debt, less current maturities	1,588,269	1,196,277	3,019,738	2,099,171	2,081,653
Shareholders' equity	1,540,552	859,588	1,332,501	1,115,742	1,179,850
Total liabilities and shareholders' equity	3,477,420	2,358,894	4,822,352	5,955,771	3,707,057

(1) We have completed numerous acquisitions and dispositions which impact the comparability of the selected financial data between periods. See Note 4. Divestitures and acquisitions in our notes to consolidated financial statements.

(2) We designated a midstream segment during 2008. Upon closing of the formation of TGGT on August 14, 2009, 50% of our interest in our East Texas/North Louisiana midstream operations (excluding the Vernon Field midstream assets), our Midstream operations no longer meet the criteria to be designated as a separate business segment. Effective August 14, 2009, net operating activity for the Vernon Field midstream assets, including intercompany eliminations are reported as a component of "Gathering and transportation" expense.

(3) Share-based compensation pursuant to Financial Accounting Standards Board, or FASB, ASC Topic 718 Compensation—Stock Compensation, included in oil and natural gas production costs is $1.0 million, $2.8 million, and $4.2 million for the years ended December 31, 2010, 2009 and 2008, respectively.

(4) Share-based compensation pursuant to FASB ASC Topic 718 Compensation—Stock Compensation, included in general and administrative expenses is $15.8 million , $16.2 million and $11.8 million for the years ended December 31, 2010, 2009 and 2008, respectively.

(5) We do not designate our derivative financial instruments as hedges and, as a result, the changes in the fair value of our derivative financial instruments are recognized directly in our statement of operations. See "Item 7. Management's discussion and analysis of financial condition and results of operations—Critical accounting policies—Accounting for derivatives" for a description of this accounting method.

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

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

Overview and history

We are an independent oil and natural gas company engaged in the exploration, exploitation, development and production of onshore North American oil and natural gas properties. Our principal operations are conducted in the East Texas/North Louisiana, Appalachia and Permian producing areas. In addition to our oil and natural gas producing operations, we own 50% interests in two midstream joint ventures located in East Texas/North Louisiana and Appalachia.

Historically, we used acquisitions and vertical drilling as our vehicle for growth. As a result of our acquisitions, we accumulated an inventory of drilling locations and acreage holdings with significant potential in the Haynesville/Bossier and Marcellus shale resource plays. The accumulation of this shale potential allowed us to shift our focus to appraise and develop these shales, primarily through horizontal drilling, divest of properties that were outside our areas of focus, and to enter into joint ventures with BG Group to develop the Haynesville shale, the Marcellus shale, and our midstream operations.

In 2010 and 2009, we entered into two upstream joint ventures with BG Group, the Appalachia JV and the East Texas/North Louisiana JV, through the sale of 50% of certain oil and natural gas properties located in Appalachia, East Texas and North Louisiana. We also entered into two midstream joint ventures with BG Group, TGGT and the Appalachia Midstream JV. The closing of our upstream and midstream joint venture transactions enabled us to accelerate our horizontal drilling program in East Texas/North Louisiana and strategically add to our acreage position through two 2010 joint acquisitions in the Haynesville shale and one transaction in Appalachia, all with BG Group. The impact of our 2009 divestitures and 2010 and 2009 joint ventures resulted in significant reductions to our Proved Reserves, production volumes, revenue and operating expenses. While the reductions had a negative impact on our results of operations, particularly in 2009 and throughout most of 2010, our shift to horizontal drilling and the accelerated drilling plan has resulted in Proved Reserves and production being restored to pre-divestiture levels.

Our primary strategy is to appraise, develop and exploit our Haynesville, Bossier and Marcellus shale resources, primarily through horizontal drilling, and to leverage our complementary midstream gathering facilities to promptly transport our production to multiple market outlets. Future acquisitions remain targeted on supplementing our shale resource holdings in the East Texas/North Louisiana and Appalachian areas. We currently plan to continue to develop vertical drilling opportunities in our Permian area as this region has high oil reserves and natural gas with a high liquid content.

We expect to continue to grow by leveraging our management and technical team's experience, appraising and developing our shale resource plays, drilling our multi-year inventory of development locations and accumulating undeveloped acreage in shale areas and implementing exploitation projects. We employ the use of debt, currently represented by a credit agreement with a borrowing base of $1.0 billion, of which $549.0 million was drawn as of February 17, 2011, and $750.0 million of the 2018 Notes outstanding, along with a comprehensive derivative financial instrument program to mitigate commodity price volatility, to support our strategy.

As of December 31, 2010, the PV-10 of our Proved Reserves was approximately $1.4 billion and the standardized measure was $1.2 billion (see "Item 1. Business—Summary of geographic areas of operations" for a reconciliation of PV-10 to Standardized Measure of Proved Reserves). For the year ended December 31, 2010, we produced 112.0 Bcfe of oil and natural gas. Based on the 112.0 Bcfe of production, this translates to a Reserve Life of approximately 13.4 years.

In 2010, we drilled 207 wells and completed 205 gross (97.2 net) wells with 99.0% drilling success rate. Our 2010 development, exploitation and other oil and natural gas property capital expenditures totaled $346.6 million, net of $337.5 million of East Texas/North Louisiana Carry and $12.6 million of Appalachia Carry paid for our benefit by BG Group. In addition, we leased $46.9 million of undeveloped acreage in the Haynesville/Bossier shale resource play in East Texas/North Louisiana and $48.5 million of undeveloped acreage in the Marcellus shale resource play in Appalachia. Investments in our midstream equity investments were $143.7 million and corporate, gathering, and seismic capital expenditures totaled an additional $119.4 million. In addition, we completed $533.9 million of acquisitions, which were mostly undeveloped acreage in the Haynesville/Bossier and Marcellus shale resource plays.

Our plans for 2011 are focused on the Haynesville/Bossier and Marcellus shales. Our budgeted capital expenditures total $976.2 million, of which $864.6 million is allocated to our East Texas/North Louisiana and Appalachia regions. In East Texas and North Louisiana, our capital expenditures for the East Texas/North Louisiana JV are expected to total $757.0 million. In Appalachia, our planned capital expenditures for the Appalachia JV are expected to total $82.8 million. Our 2010 capital expenditures were favorably impacted by the East Texas/North Louisiana Carry. In 2011, our capital expenditures in Appalachia will benefit from the Appalachia Carry. As of December 31, 2010, the remaining balance of East Texas/North Louisiana Carry was approximately $30.2 million, which we anticipate will be fully utilized by the first quarter of 2011 and the remaining balance of the Appalachia Carry, after estimated contractual adjustments for post closing reductions to the original carry amount, was approximately $126.8 million.

For 2011, TGGT's capital expenditure budget of $237.1 million will focus primarily on well hook-ups in DeSoto Parish and adding infrastructure in the Shelby Area. The management of TGGT is also evaluating several expansion projects. On January 31, 2011, TGGT closed the TGGT Credit Agreement. We expect the TGGT Credit Agreement, together with their cash flows from operations, will be sufficient to fund their 2011 capital expenditure programs. We expect to fund equity contributions to the Appalachia Midstream JV in the future depending on the results of the development and appraisal program.

Like all oil and natural gas production companies, we face the challenge of natural production declines. We attempt to overcome this natural decline by drilling to identify and develop additional reserves and add reserves through acquisitions. As of December 31, 2010, 97.1% of our estimated Proved Reserves were natural gas. Consequently, our results of operations are particularly impacted by natural gas markets.

Critical accounting policies

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

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

Estimates of Proved Reserves

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

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the technical qualifications, experience and judgment of the persons preparing the estimates.

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. The assumptions used for our Haynesville and Marcellus well and reservoir characteristics and performance are subject to further refinement as more production history is accumulated.

You should not assume that the present value of future net cash flows represents the current market value of our estimated Proved Reserves. In accordance with SEC requirements, we based the estimated discounted future net cash flows from Proved Reserves according to the requirements in the SEC's Release No. 33-8995 Modernization of Oil and Gas Reporting, or Release No. 33-8995. Actual future prices and costs may be materially higher or lower than the prices and costs used in the preparation of the estimate. Further, the mandated discount rate of 10% may not be an accurate assumption of future interest rates.

Proved Reserve 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, making it uneconomical to drill or produce from higher cost fields. In addition, a decline in Proved Reserves may impact the outcome of our assessment of our oil and natural gas properties and require an impairment of the carrying value of our oil and natural gas properties.

Proved Reserves are defined as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimates are a deterministic estimate or probabilistic estimate. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes both the area identified by drilling and limited by fluid contacts, if any, and adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil and gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and the project has been approved for development by all necessary parties and entities, including governmental entities.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Business combinations

For the periods covered by this Annual Report on Form 10-K, we use the Financial Accounting Standards Board, or FASB, Accounting Standard Codification, or ASC, Subtopic 805-10 for Business Combinations to record our acquisitions of oil and natural gas properties or entities which we acquire beginning January 1, 2009. ASC 805-10 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 ASC 805-10 requires significant estimates to be made by management using information available at the time of acquisition. Since these estimates require the use of significant judgment, actual results could vary as the estimates are subject to changes as new information becomes available.

Accounting for derivatives

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

Share-based payments

We account for share-based payments to employees using the methodology prescribed in FASB ASC Topic 718 for Compensation—Stock Compensation. At December 31, 2010, our employees and directors held options under EXCO's 2005 Long-Term Incentive Plan, or the 2005 Incentive Plan, to purchase 16,478,926 shares of EXCO common stock at prices ranging from \$6.33 per share to \$38.01 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 \$7.34 per share to \$12.77 per share. ASC Topic 718 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 2010 was \$23.2 million, of which \$6.4 million was capitalized as part of our oil and natural gas properties. In 2009 and 2008, a total of \$24.1 million and \$20.0 million, respectively, of share-based compensation was incurred, of which \$5.1 million and \$4.0 million, respectively, was capitalized.

Accounting for oil and natural gas properties

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

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

During April 2008 we initiated leasing projects to acquire shale drilling rights in both our Appalachia and East Texas/North Louisiana operating areas. In accordance with our policy and FASB ASC Subtopic 835-20 for Capitalization of Interest, we began capitalizing interest on unproved properties.

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 quantity of Proved Reserves. This rate is applied to our total production for the period, and the appropriate expense is recorded. We capitalize the portion of general and administrative costs, including share-based compensation, that is attributable to our acquisition, exploration, exploitation and development activities.

Under the full cost method of accounting, sales, dispositions and other oil and natural gas property retirements are generally accounted for as adjustments to the full cost pool, with no recognition of gain or loss unless the disposition would significantly alter the relationship between capitalized costs and Proved Reserves. The transactions to form our 2010 Appalachia JV and our 2009 East Texas/North Louisiana JV, along with certain of our 2009 divestitures, resulted in significant alterations to our depletion rate and we determined that gain recognition was appropriate for these transactions. Gain or loss recognition on divestiture or abandonment of oil and natural gas properties where disposition would result in a significant alteration of the depletion rate requires allocation of a portion of the amortizable full cost pool based on the relative estimated fair value of the disposed oil and natural gas properties to the estimated fair value of total Proved Reserves. As discussed under "Estimates of Proved Reserves," estimating oil and natural gas reserves involves numerous assumptions.

Pursuant to Rule 4-10(c)(4) of Regulation S-X, at the end of each quarterly period, companies that use the full cost method of accounting for their oil and natural gas properties must perform a limitation on capitalized costs, or ceiling test. The ceiling test involves comparing the net book value of the full cost pool, after taxes, to the full cost ceiling limitation defined below. In the event the full cost ceiling is less than the full cost pool, we must record a ceiling test write-down of our oil and natural gas properties to the value of the full cost ceiling. The full cost ceiling limitation is computed as the sum of the present value of estimated future net revenues from our Proved Reserves by applying average prices as prescribed by the SEC's Release No. 33-8995, less estimated future expenditures (based on current costs) to develop and produce the Proved Reserves, discounted at 10%, plus the cost of properties not being amortized and the lower of cost or estimated fair value of unproved properties included in the costs being amortized, net of income tax effects.

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

Goodwill

A change in control transaction involving an equity buyout on October 3, 2005, required the application of the purchase method of accounting pursuant to ASC 805-10 and goodwill of $220.0 million was recognized. Additional goodwill of $250.1 million was recognized from our 2006 acquisitions.

The transactions to form our 2010 Appalachia JV and our 2009 East Texas/North Louisiana JV, along with certain of our 2009 divestitures, each caused significant alterations to our depletion rate and we therefore evaluated the goodwill associated with these properties. As a result of our analysis, we eliminated $51.4 million of goodwill in 2010 and $177.6 million of goodwill in 2009 by reducing the gains associated with these transactions. In addition, the transaction to form TGGT triggered the write off of $11.4 million of goodwill against the associated gain and the transfer of $11.4 million of goodwill to the TGGT investment.

As of December 31, 2010, our consolidated goodwill totals $218.3 million. Not all of our goodwill is currently deductible for income tax purposes. Furthermore, in accordance with FASB ASC Topic 350-Intangibles—Goodwill and Other, goodwill is not amortized, but is tested for impairment on an annual basis, or more frequently as impairment indicators arise. Impairment tests, which involve the use of estimates related to the fair market value of the business operations with which goodwill is associated, are subject to various assumptions and judgments. We use a combination of valuation techniques, including discounted cash flow projections and market comparable analyses to evaluate our goodwill for possible impairment. 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. As of December 31, 2010, we did not have any impairment of our goodwill.

Asset retirement obligations

We follow FASB ASC Subtopic 410-20 for Asset Retirement Obligations to account for legal obligations associated with the retirement of long-lived assets. ASC 410-20 requires these obligations be recognized at their estimated fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost should be capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. The costs of plugging and abandoning oil and natural gas properties fluctuate with costs associated with the industry. We periodically assess the estimated costs of our asset retirement obligations and adjust the liability according to these estimates.

Accounting for income taxes

Income taxes are accounted for using the liability method of accounting in accordance FASB ASC Topic 740 for Income Taxes. We must make certain estimates related to the reversal of temporary differences, and actual results could vary from those estimates. Deferred taxes are recorded to reflect the tax benefits and consequences of future years' differences between the tax basis of assets and liabilities and their financial reporting basis. We record a valuation allowance to reduce deferred tax assets if it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Recent accounting pronouncements

On December 21, 2010, FASB issued Accounting Standards Update, or ASU, No. 2010-29—Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations, or ASU 2010-29. ASU 2010-29 specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The update also expands the supplemental pro forma disclosures under Topic 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The update is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. This update was adopted by us on January 1, 2011 and will be considered if we enter into a business combination transaction.

On December 17, 2010, the FASB issued ASU No. 2010-28—Intangibles—Goodwill and Other (Topic 350): When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts, or ASU 2010-28. ASU 2010-28 modifies Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors indicating that an impairment may exist. The update is effective for interim and annual reporting periods beginning after December 15, 2010. This update will be considered on an interim and annual basis when we review and perform our goodwill impairment test.

On January 21, 2010, the FASB issued ASU, No. 2010-06—Fair Value Measurement and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements, or ASU 2010-06. ASU 2010-06 requires transfers, and the reasons for the transfers, between Levels 1 and 2 be disclosed. Fair value measurements using significant unobservable inputs should be presented on a gross basis and the fair value measurement disclosure should be reported for each class of asset and liability. Disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements will be required for fair value measurements that fall in either Level 2 or 3. The update is effective for interim and annual reporting periods beginning after December 15, 2009. See "Note 5. Derivative financial instruments and fair value measurements" in the notes to our consolidated financial statements included in this Annual Report on Form 10-K for the impact to our disclosures.

Our results of operations

A summary of key financial data for 2010, 2009 and 2008 related to our results of operations for the years then ended is presented below.

	Year ended December 31,			Year to year change	
(dollars in thousands, except per unit price)	2010	2009	2008	2010-2009	2009-2008
Production:					
Oil (Mbbls)	688	1,571	2,236	(883)	(665)
Natural gas (Mmcf)	107,878	118,736	131,159	(10,858)	(12,423)
Total production (Mmcfe)(1)	112,006	128,162	144,575	(16,156)	(16,413)
Oil and natural gas revenues before derivative financial instrument activities:					
Oil	$ 52,411	$ 84,397	$ 216,727	$ (31,986)	$(132,330)
Natural gas	462,815	466,108	1,188,099	(3,293)	(721,991)
Total oil and natural gas	$515,226	$ 550,505	$1,404,826	$ (35,279)	$(854,321)
Midstream operations:(2)					
Midstream revenues (before intersegment eliminations)	$ —	$ 76,478	$ 147,636	$ (76,478)	$ (71,158)
Midstream operating expenses (before intersegment eliminations)	—	56,372	112,705	(56,372)	(56,333)
Midstream operating profit (before intersegment eliminations)	—	20,106	34,931	(20,106)	(14,825)
Intersegment eliminations	—	(20,356)	(32,296)	20,356	11,940
Midstream operating profit (after intersegment eliminations)	$ —	$ (250)	$ 2,635	$ 250	$ (2,885)
Oil and natural gas derivative financial instruments:					
Cash settlements (payments) on derivative financial instruments	$217,455	$ 478,463	$ (109,300)	$(261,008)	$ 587,763
Non-cash change in fair value of derivative financial instruments	(70,939)	(246,438)	493,689	175,499	(740,127)
Total derivative financial instrument activities	$146,516	$ 232,025	$ 384,389	$ (85,509)	$(152,364)

(dollars in thousands, except per unit price)	Year ended December 31, 2010	2009	2008	Year to year change 2010-2009	2009-2008
Average sales price (before cash settlements of derivative financial instruments):					
Oil (Bbl)	$ 76.18	$ 53.72	$ 96.93	$ 22.46	$ (43.21)
Natural gas (per Mcf)	4.29	3.93	9.06	0.36	(5.13)
Natural gas equivalent (per Mcfe)	4.60	4.30	9.72	0.30	(5.42)
Costs and expenses:					
Oil and natural gas operating costs(3)	$ 84,145	$ 138,659	$ 161,172	$ (54,514)	$ (22,513)
Production and ad valorem taxes	24,039	38,970	76,899	(14,931)	(37,929)
Gathering and transportation	54,877	18,960	14,206	35,917	4,754
Depletion	179,613	196,515	435,595	(16,902)	(239,080)
Depreciation and amortization	17,350	24,923	24,719	(7,573)	204
General and administrative(4)	105,114	99,177	87,568	5,937	11,609
Interest expense	45,533	147,161	161,638	(101,628)	(14,477)
Costs and expenses (per Mcfe):					
Oil and natural gas operating costs	$ 0.75	$ 1.08	$ 1.11	(0.33)	(0.03)
Production and ad valorem taxes	0.21	0.30	0.53	(0.09)	(0.23)
Gathering and transportation	0.49	0.15	0.10	0.34	0.05
Depletion	1.60	1.53	3.01	0.07	(1.48)
Depreciation and amortization	0.15	0.19	0.17	(0.04)	0.02
General and administrative	0.94	0.77	0.61	0.17	0.16
Net income (loss)	$671,926	$(496,804)	$(1,733,471)	$1,168,730	$1,236,667
Preferred Stock dividends	—	—	(76,997)	—	76,997
Income (loss) available to common shareholders	$671,926	$(496,804)	$(1,810,468)	$1,168,730	$1,313,664

(1) Mmcfe is calculated by converting one barrel of oil into six Mcf of natural gas.

(2) Upon closing the formation of TGGT on August 14, 2009, our midstream operations no longer met the criteria to be designated as a separate business segment. Our 50% interest in TGGT and our 50% interest in the Appalachia Midstream JV are accounted for using the equity method of accounting. Effective August 14, 2009, all operating activity, including intersegment eliminations, for the Vernon Field midstream assets are reported as a component in "Gathering and transportation" expense.

(3) Share-based compensation, pursuant to FASB ASC Topic 718, included in oil and natural gas operating costs, is \$1.0 million, \$2.8 million, and \$4.2 million for the years ended December 31, 2010, 2009 and 2008, respectively.

(4) Share-based compensation, pursuant to FASB ASC Topic 718, included in general and administrative expenses is \$15.8 million, \$16.2 million and \$11.8 million for the years ended December 31, 2010, 2009 and 2008, respectively.

The following is a discussion of our financial condition and results of operations for the years ended December 31, 2010, 2009 and 2008.

The comparability of our results of operations for 2010, 2009 and 2008 is impacted by:

- the East Texas/North Louisiana JV;
- the Appalachia JV;
- 2009 divestitures;
- other dispositions of oil and natural gas properties;
- significant acquisitions of producing oil and natural gas properties;

- fluctuations in oil and natural gas prices, which impact our oil and natural gas reserves, revenues, cash flows and net income or loss;
- mark-to-market accounting used for our derivative financial instruments gains or losses;
- changes in Proved Reserves and production volumes, including the impact of SEC Release No. 33-8995, effective December 31, 2009, and their impact on depletion;
- the equity method of accounting for our investments;
- the impact of our 2010 and 2009 natural gas production volumes from our horizontal drilling activities in the Haynesville/Bossier and Marcellus shales;
- the impact of ceiling test write-downs in 2009 and 2008;
- gains on sales of assets in 2010 and 2009; and
- significant changes in the amount of our long-term debt and the conversion of $2.0 billion of preferred stock into common stock in July 2008.

General

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, particularly the recent worldwide economic recession which continues to affect oil and natural gas prices and demand;
- the level of domestic and international industrial demand for manufacturing operations;
- 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;
- 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; and
- trends in fuel use and government regulations that encourage less fuel use and encourage or mandate alternative fuel use.

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 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 or natural gas we produce. We sell the majority of the oil we produce under short-term contracts using market sensitive pricing. The majority of our 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 sales 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 price received for natural gas sold on the spot market varies daily, reflecting changing market conditions.

For the year ended December 31, 2010, sales to BG Energy Merchants LLC and Louis Dreyfus Energy Services LP accounted for approximately 21.5% and 10.1%, respectively, of total consolidated revenues. BG Energy Merchants LLC is a subsidiary of BG Group. For the year ended 2009, there were no sales to any individual customer which exceeded 10% of our consolidated revenues or were considered material to our operations. For the year ended December 31, 2008, sales to Crosstex Gulf Coast Marketing, and to Atmos Energy Marketing L.L.C. and its affiliates, accounted for approximately 12.0% and 11.2%, respectively, of total consolidated revenues. The loss of any significant customer may cause a temporary interruption in sales of, or a lower price for, our oil and natural gas, but we believe that the loss of any one customer would not have a material adverse effect on our results of operations or financial condition.

We may be unable to market all of 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 reserves. 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. Recent economic conditions related to the liquidity and creditworthiness of our purchasers may expose us to risk with respect to the ability to collect payments for the oil and natural gas we deliver.

Summary

For the years ended December 31, 2010, 2009 and 2008, we had net income of $671.9 million and net losses available to common shareholders of $496.8 million and $1.8 billion, respectively.

Our results of operations for 2010 were impacted by both the continued expansion of our activity in the Haynesville shale and the Appalachia JV. The Appalachia JV resulted in the sale of a 50% undivided interest in substantially all of our Appalachian oil and natural gas proved and unproved properties for cash consideration of approximately $790.2 million, after reducing the original proceeds by $45.0 million in the fourth quarter for estimated post-closing adjustments. In connection with the Appalachia JV, we recorded a pretax gain of $528.9 million. The net proceeds and gain from the Appalachia JV are subject to further adjustments until the purchase price is finalized, which we expect to occur during 2011.

During 2009, we recorded a first quarter $1.3 billion non-cash ceiling test write-down, completed a divestiture program, or the 2009 Divestitures, entered into the East Texas/North Louisiana JV and formed TGGT. Proceeds from the 2009 Divestitures and joint venture transactions were approximately $2.1 billion excluding the $400.0 million East Texas/North Louisiana Carry. These transactions resulted in significant decreases in our full cost pool, gathering assets, goodwill, operating assets and liabilities, and we recognized gains totaling approximately $691.9 million. Upon completion of the 2009 Divestitures, we no longer operate in the Mid-Continent, Rockies and Ohio regions. As a result, when comparing the 2010 operating results to 2009 and the 2009 operating results to 2008, there are significant declines in our production of oil and natural gas, revenues and operating costs. Accordingly, we are presenting certain pro forma comparisons to facilitate comparison of operating data between 2010, 2009, and 2008.

In addition, the impact of fluctuations in oil and natural gas prices is significant to our results of operations. There were large fluctuations in oil and natural gas prices during 2010, 2009 and 2008. In 2010, we received average oil prices of $76.18 per Bbl compared to $53.72 per Bbl in 2009 and $96.93 per Bbl in 2008. As for natural gas prices, in 2010 we received average prices of $4.29 per Mcf compared to $3.93 per Mcf in 2009 and $9.06 per Mcf in 2008. In addition, we do not designate our derivative financial instruments as hedges. Therefore, we mark the non-cash changes in the fair value of our unsettled derivative financial instruments to market at the end of each reporting period. Due to significant fluctuations in the price of oil and natural gas during 2010, 2009 and 2008, the impacts of derivative financial instruments, including cash settlements or receipts with our counterparties and the non-cash mark-to-market impacts, totaled net gains of $146.5 million, $232.0 million and $384.4 million for 2010, 2009 and 2008, respectively.

Oil and natural gas revenues, production and prices

Total equivalent production volumes were 112.0 Bcfe, 128.2 Bcfe, and 144.6 Bcfe for 2010, 2009 and 2008, respectively. The declines from year to year are primarily a result of the Appalachia JV, the 2009 Divestitures and the East Texas/North Louisiana JV. We are presenting the following table which eliminates the impact of these transactions on production to provide a more meaningful analysis of on-going production activity. The pro forma adjustments below reduce our actual production as if the transactions had occurred on January 1 of the respective year.

	Twelve months ended December 31,							
	2010			2009			Period to period change	
(in Mmcfe)	Actual production	Pro forma adjustment(1)	Pro forma production	Actual production	Pro forma adjustment(2)	Pro forma production	Actual production	Pro forma production
Producing region:								
East Texas/North Louisiana	95,423	—	95,423	82,138	(18,866)	63,272	13,285	32,151
Appalachia	9,427	(2,707)	6,720	19,184	(12,256)	6,928	(9,757)	(208)
Permian and other	7,156	—	7,156	8,827	(974)	7,853	(1,671)	(697)
Mid-Continent	—	—	—	18,013	(18,013)	—	(18,013)	—
Total	112,006	(2,707)	109,299	128,162	(50,109)	78,053	(16,156)	31,246

(1) The pro forma adjustments reduce production volumes attributable to the properties affected by the Appalachia JV as if the sale had occurred on January 1, 2010.

(2) The pro forma adjustments reduce production volumes attributable to properties sold in 2009 and properties affected by both the East Texas/North Louisiana JV and the Appalachia JV as if these sales had occurred on January 1, 2009.

On a pro forma basis, production in our East Texas/North Louisiana region for the year 2010 increased by 32.2 Bcfe from 2009. This increase was a result of the successful development of our Haynesville shale, which resulted in a production increase of 44.5 Bcfe for year 2010, when compared to the same period in 2009. These increases were partially offset by production declines of 3.8 Bcfe in our Cotton Valley area and 8.5 Bcfe in our Vernon Field the year 2010, when compared to the same prior year period. These declines are primarily the result of the suspension of vertical drilling operations in 2009 and normal production declines. The Appalachia and Permian divisions also experienced production declines due primarily to suspension of conventional, vertical drilling programs in both areas during 2009. During 2010, in response to increases in oil prices, we re-initiated drilling operations in our Permian Basin division and expect to maintain a two rig drilling program in 2011. In Appalachia, we began our horizontal Marcellus shale drilling operations, focusing on appraisal wells in our east central and west central Pennsylvania areas. During 2011, we expect to continue to evaluate the data collected from the appraisal wells and commence development wells in certain areas.

As we have expanded our drilling activity in the Haynesville shale and refined certain drilling and completion techniques, we have begun shutting in production from wells which are in close proximity to fracture stimulation operations to protect the reservoir and the offset wells. Due to our significant drilling activities, particularly in our DeSoto Parish area, these shut in volumes can be significant. In our East Texas/North Louisiana producing area, the average shut in production volumes for the fourth quarter 2010 were approximately 21.0 Mmcf per day, or approximately 10% of our Haynesville shale production. We expect to continue the practice of shutting in offsetting wells throughout 2011 and have budgeted an average shut in range of 7.0 – 10.0% for such volumes. As our drilling activities in the Shelby Area and Marcellus areas expand, we expect that shut in volumes will also occur.

	Twelve months ended December 31,							
	2009			2008			Period to period change	
(in Mmcfe)	Actual production	Pro forma adjustment(1)	Pro forma production	Actual production	Pro forma adjustment(2)	Pro forma production	Actual production	Pro forma production
Producing region:								
East Texas/North Louisiana	82,138	(18,866)	63,272	87,540	(24,734)	62,806	(5,402)	466
Appalachia	19,184	(5,328)	13,856	20,899	(5,746)	15,153	(1,715)	(1,297)
Permian and other	8,827	(974)	7,853	11,897	(2,124)	9,773	(3,070)	(1,920)
Mid-Continent	18,013	(18,013)	—	24,239	(24,239)	—	(6,226)	—
Total	128,162	(43,181)	84,981	144,575	(56,843)	87,732	(16,413)	(2,751)

(1) The pro forma adjustments reduce production volumes attributable to properties sold in 2009 and properties affected by the East Texas/North Louisiana JV as if these sales had occurred on January 1, 2009.

(2) The pro forma adjustments increased production volumes attributable to properties purchased in 2008 and reduced production volumes attributable to properties sold in 2009 and properties affected by the East Texas/North Louisiana JV as if these purchases and sales had occurred on January 1, 2008.

On a pro forma basis, production in our East Texas/North Louisiana region for the year 2009 increased by 0.5 Bcfe from 2008. This increase reflects increased production resulting from our horizontal Haynesville shale drilling results which were offset by normal production declines along with suspension of our conventional, vertical drilling operations. The Appalachia and Permian divisions also experienced production declines due primarily to suspension of conventional, vertical drilling programs in both areas during 2009.

The following table presents our revenues, production and prices by major producing areas, based on historical data, for 2010, 2009, and 2008.

	Year ended December 31,								
	2010			2009			Year to date change		
(dollars in thousands, except per unit rate)	Revenue	Production (Mmcfe)	$/Mcfe	Revenue	Production (Mmcfe)	$/Mcfe	Revenue	Production (Mmcfe)	$/Mcfe
Producing region:									
East Texas/North Louisiana	$397,680	95,423	$ 4.17	315,710	$ 82,138	$3.84	81,970	$ 13,285	$ 0.33
Appalachia	45,962	9,427	4.88	91,832	19,184	4.79	(45,870)	(9,757)	0.09
Permian and other	71,584	7,156	10.00	58,784	8,827	6.66	12,800	(1,671)	3.34
Mid-Continent	—	—	—	84,179	18,013	4.67	(84,179)	(18,013)	(4.67)
Total	515,226	112,006	4.60	$550,505	128,162	4.30	(35,279)	$(16,156)	0.30

	Year ended December 31,								
	2009			2008			Year to date change		
(dollars in thousands, except per unit rate)	Revenue	Production (Mmcfe)	$/Mcfe	Revenue	Production (Mmcfe)	$/Mcfe	Revenue	Production (Mmcfe)	$/Mcfe
Producing region:									
East Texas/North Louisiana	$315,710	82,138	$3.84	$ 802,579	87,540	$ 9.17	$(486,869)	(5,402)	$(5.33)
Appalachia	91,832	19,184	4.79	209,221	20,899	10.01	(117,389)	(1,715)	(5.22)
Permian and other	58,784	8,827	6.66	149,878	11,897	12.60	(91,094)	(3,070)	(5.94)
Mid-Continent	84,179	18,013	4.67	243,148	24,239	10.03	(158,969)	(6,226)	(5.36)
Total	$550,505	128,162	4.30	$1,404,826	144,575	9.72	$(854,321)	(16,413)	(5.42)

Total oil and natural gas revenues for 2010 were $515.2 million compared with $550.5 million for 2009 and $1.4 billion for 2008. For 2010, natural gas represented 89.8% of our oil and natural gas revenues, compared to 2009, where natural gas represented 84.7% of our oil and natural gas revenues and 2008, where natural gas represented 84.6% of our oil and natural gas revenues.

The 6.4% decrease in oil and gas revenues in 2010 from 2009 is primarily a result of the reduced volumes attributable to the Appalachia JV, the full year impact of the 2009 Divestitures and the East Texas/North Louisiana JV, partially offset by increases in the prices. The average sales price of oil per Bbl, excluding the impact of derivative financial instruments, increased from $53.72 per Bbl in 2009 to $76.18 per Bbl in 2010, or 41.8%. The average natural gas sales price, excluding the impact of derivative financial instruments, was $4.29 per Mcf, an increase of 9.2% for 2010 compared with $3.93 per Mcf 2009.

The 60.8% decrease in oil and gas revenues from 2008 to 2009 is primarily a result of the 2009 Divestitures and the East Texas/North Louisiana JV and declines in the prices. The average sales price of oil per Bbl, excluding the impact of derivative financial instruments, decreased from $96.93 per Bbl in 2008 to $53.72 per Bbl in 2009, or 44.6%. The average natural gas sales price in 2009, excluding the impact of derivative financial instruments, was $3.93 per Mcf, a decrease of 56.6% compared with $9.06 per Mcf in 2008. The decline in 2009 from 2008 prices reflects a commodity price decline trend that started at end of the third quarter of 2008 and continued through 2009.

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, estimates of oil and natural gas in storage, weather and other seasonal conditions, including hurricanes and tropical storms. Market conditions involving over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect the volatility to continue in the future. Changes in oil and natural gas prices have a significant impact on our oil and natural gas revenues, cash flows, quantities of estimated Proved Reserves and related liquidity. Assuming our 2010 production levels, a change of $0.10 per Mcf of natural gas sold would result in an annual increase or decrease in revenues of approximately $107.9 million and a change of $1.00 per Bbl of oil sold would result in an annual increase or decrease in revenues and cash flow of approximately $0.7 million without considering the effects of derivative financial instruments. In addition, our production volumes are impacted by shut in volumes of natural gas due to operational requirements associated with fracture stimulation on near-by horizontal wells, seasonal supply and demand conditions from end users and general maintenance and repairs to our wells. While these shut in volumes are typically for short periods of time, they may have impacts to our revenues, cash flows and results of operations.

Oil and natural gas operating costs

Our oil and natural gas operating costs for 2010, 2009, and 2008 were $84.1 million, $138.7 million and $161.2 million, respectively. The decreases from year to year are due primarily to our divestitures in both 2010 and 2009. Management believes that analyses on a per Mcfe basis provide a more meaningful measure than the absolute dollar decreases since the divestitures in 2010 and 2009 and the acquisitions in 2008 significantly impacted the absolute dollar amounts.

As shown in the table below, on a per Mcfe basis, oil and natural gas operating expenses for 2010 decreased $0.33 per Mcfe from the same period in 2009. The net $0.31 per Mcfe decrease in East Texas/North Louisiana is a result of increased production in our Haynesville shale, which has a relatively low lease operating rate per Mcfe, partially offset by costs in our Vernon Field and Cotton Valley area where operating costs contain a large fixed cost component and production volumes have decreased due to suspension of drilling. The increases in Appalachia and Permian are primarily the result of production declines associated with suspended drilling operations without a corresponding decrease in costs to offset the decline in production.

	Twelve months ended December 31,								
	2010			2009			Period to period change		
(in thousands)	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total
Producing region:									
East Texas/North									
Louisiana	$48,255	$10,735	$58,990	$ 65,827	$10,220	$ 76,047	$(17,572)	$ 515	$(17,057)
Appalachia	14,929	216	15,145	29,244	1,455	30,699	(14,315)	(1,239)	(15,554)
Permian and other	9,127	883	10,010	10,091	1,521	11,612	(964)	(638)	(1,602)
Mid-Continent	—	—	—	19,541	760	20,301	(19,541)	(760)	(20,301)
Total	$72,311	$11,834	$84,145	$124,703	$13,956	$138,659	$(52,392)	$(2,122)	$(54,514)

	Twelve months ended December 31,								
	2010			2009			Period to period change		
(per Mcfe)	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total
Producing region:									
East Texas/North									
Louisiana	$ 0.50	$ 0.11	$ 0.61	$ 0.80	$ 0.12	$ 0.92	$ (0.30)	$ (0.01)	$ (0.31)
Appalachia	1.58	0.02	1.60	1.52	0.08	1.60	0.06	(0.06)	—
Permian and other	1.28	0.12	1.40	1.14	0.17	1.31	0.14	(0.05)	0.09
Mid-Continent	—	—	—	1.08	0.04	1.12	(1.08)	(0.04)	(1.12)
Operating costs per Mcfe	0.64	0.11	0.75	0.97	0.11	1.08	(0.33)	—	(0.33)

As shown in the table below, on a per Mcfe basis, oil and natural gas operating costs for the year ended December 31, 2009 decreased by $0.03 per Mcfe from year ended December 31, 2008. Direct lease operating expenses per unit decreased by $0.02 per Mcfe, or 2.0%, for the year ended December 31, 2009, from the year ended December 31, 2008. These decreases are principally the result of lower operating costs in our East Texas/North Louisiana area where increasing volumes from Haynesville wells benefit the unit rate. Benefits from the Haynesville results are partially offset by declining volumes from our base production in Vernon and Cotton Valley that tend to increase the unit rate. The increases in Appalachia and Permian were a result of suspended drilling operations in 2009, which resulted in production declines, but not a corresponding decline in costs to offset the production declines.

	Twelve months ended December 31,								
	2009			2008			Period to period change		
(in thousands)	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total
Producing region:									
East Texas/North									
Louisiana	$ 65,827	$10,220	$ 76,047	$ 74,720	$11,950	$ 86,670	$ (8,893)	$(1,730)	$(10,623)
Appalachia	29,244	1,455	30,699	29,548	2,056	31,604	(304)	(601)	(905)
Permian and other	10,091	1,521	11,612	10,916	1,941	12,857	(825)	(420)	(1,245)
Mid-Continent	19,541	760	20,301	28,987	1,054	30,041	(9,446)	(294)	(9,740)
Total	$124,703	$13,956	$138,659	$144,171	$17,001	$161,172	$(19,468)	$(3,045)	$(22,513)

	Twelve months ended December 31,						Period to period change		
	2009			2008					
(per Mcfe)	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total
Producing region:									
East Texas/North Louisiana	$0.80	$0.12	$0.92	$0.85	$0.14	$0.99	$(0.05)	$(0.02)	$(0.07)
Appalachia	1.52	0.08	1.60	1.41	0.10	1.51	0.11	(0.02)	0.09
Permian and other	1.14	0.17	1.31	0.92	0.16	1.08	0.22	0.01	0.23
Mid-Continent	1.08	0.04	1.12	1.20	0.04	1.24	(0.12)	(0.00)	(0.12)
Operating costs per Mcfe	0.97	0.11	1.08	0.99	0.12	1.11	(0.02)	(0.01)	(0.03)

Midstream operations

Until our adoption of the equity method of accounting in connection with the formation of TGGT in August 2009, our midstream revenues were principally derived from three of our wholly owned subsidiaries:

- TGG, which owns gathering systems in East Texas and North Louisiana;
- Talco, which owns gathering systems in East Texas and North Louisiana; and
- Vernon Gathering LLC, a gathering system located in Jackson Parish, Louisiana.

Revenues in our midstream segment were primarily derived from sales of natural gas purchased for resale and fees earned from gathering, treating and compression of natural gas. We do not own any natural gas processing facilities.

TGGT holds our East Texas/North Louisiana midstream assets, exclusive of the Vernon Field gathering assets. TGGT is accounted for using the equity method of accounting. Effective with the formation of TGGT in August 2009, the net operations of Vernon Gathering are reflected as a component of “Gathering and transportation” on our consolidated statements of operations.

Due to the rapid natural gas production growth in the Haynesville/Bossier shale, TGGT has increased its throughput dramatically in its core areas of operation within East Texas and North Louisiana. TGGT’s primary customers are EXCO and BG Group. TGGT owns and operates TGG Pipeline, Ltd., or TGG, and Talco Midstream Assets, Ltd., or Talco. The assets of TGG include treating facilities and gathering pipelines that connect to downstream pipelines. Talco’s assets primarily consist of gathering pipelines that provide well hookups and lateral connections. Total throughput capacity currently exceeds 1.0 Bcf per day.

In 2010, TGG completed a 27 mile, 36–inch diameter header for gathering natural gas from Haynesville/Bossier shale and Cotton Valley wells, principally in DeSoto Parish, Louisiana. TGG operates amine, glycol, and H2S treating facilities, which treat natural gas in order to meet pipeline quality specifications for downstream transportation. TGGT’s system has access to 13 interstate and intrastate pipeline markets. TGG has approximately 126 miles of pipeline comprised of 12, 16, and 20-inch diameter pipe in its legacy East Texas area with a current throughput capacity of approximately 460 Mmcf per day. TGG continues to see growth in throughput in both its existing East Texas gathering system area as well as in its new shale-focused systems in the North Louisiana area.

Additionally, TGG has initiated major midstream expansion efforts in the Shelby Area in East Texas. Certain pipelines and facilities were completed in 2010 and upon completion in 2011, TGGT estimates it will operate approximately 72 miles of gathering systems. The current throughput capacity is approximately 190 Mmcf per day, and the throughput capacity is planned to increase to approximately 740 Mmcf per day by the third quarter of 2011. In addition, the gathering systems are expected to have treating capacity in excess of 500 Mmcf per day by year end 2011.

In addition to TGGT, we also hold an equity interest in the Appalachia Midstream JV, a midstream company in our Appalachia area of operations. As of December 31, 2010, Appalachia midstream is evaluating its alternatives which will be dependent on the results of our 2011 drilling appraisal program in the Appalachia JV.

For the year ended December 31, 2009, midstream revenues were $76.5 million compared with $147.6 million for year ended December 31, 2008. The decrease in sales for 2009 is due to the combination of lower prices received in 2009 from the sales of natural gas we purchased for resale, lower condensate prices and the adoption of the equity method of accounting for TGGT's operations on August 14, 2009. Our midstream operating expenses before intersegment elimination, which includes the cost of natural gas purchased and then resold, for the year ended December 31, 2009 decreased $56.3 million from the year ended December 31, 2008. The decrease in midstream operating expenses was primarily attributable to a decline in the prices we paid for the natural gas we purchased for resale along with the formation of TGGT and adoption of the equity method of accounting for TGGT's operations. These decreases were offset by increases in both operating expenses and gas purchases resulting from the 2008 midstream acquisitions as well as the expansion of our gathering and transportation facilities in the East Texas/North Louisiana operating area in support of our Haynesville projects.

Gathering and transportation

We report gathering and transportation costs in accordance with FASB Section 605-45-05 of Subtopic 605-45 for Revenue Recognition. We generally sell oil and natural gas under two types of agreements which are common in our industry. Both types of agreements include a transportation charge. One is a netback arrangement, under which we sell oil or natural gas at the wellhead and collect a price, net of the transportation incurred by the purchaser. In this case, we record sales at the price received from the purchaser, net of the transportation costs. Under the other arrangement, we sell oil or natural gas at a specific delivery point, pay transportation to a third party and receive proceeds from the purchaser with no transportation deduction. In this case, we record the transportation cost as gathering and transportation expense. Due to these two distinct selling arrangements, our computed realized prices, before the impact of derivative financial instruments, contain revenues which are reported under two separate bases. Gathering and transportation expenses totaled $54.9 million for year ended December 31, 2010, compared to $19.0 million for the year ended December 31, 2009 and $14.2 million for the year ended December 31, 2008. The overall increase in gathering and transportation expenses is a result of new firm transportation agreements in the Haynesville area, which commenced in February 2010, along with the fees charged by TGGT.

In connection with our change from reporting our midstream operations as a separate business segment, we began reporting the net results of operations from our Vernon Gathering system as a component of gathering and transportation expenses in the third quarter of 2009.

We have entered into firm transportation agreements with pipeline companies to facilitate sales as we expand our Haynesville volumes and report these firm transportation costs as a component of gathering and transportation expenses. By the end of 2011, our firm transportation agreements will cover over 870 Bcf per day with annual minimum gathering expenses of approximately $89.2 million.

Production and ad valorem taxes

Production and ad valorem taxes were $24.0 million, $39.0 million and $76.9 million for 2010, 2009, and 2008, respectively. On a percentage of revenue basis, before the impact of derivative financial instruments, production and ad valorem taxes were 4.7% of oil and natural gas sales for 2010, compared with 7.1% and 5.5% for 2009 and 2008, respectively. The decrease in the percentage of revenue basis for the twelve months ended December 31, 2010 compared to the same period in 2009 is primarily the result of the receipt of severance tax holidays on our Haynesville and Bossier shale wells in Louisiana. The increase in the percentage of revenue basis for the twelve months ended December 31, 2009 compared to the same period in 2008 is primarily the result of the different taxing jurisdictions in which we operate. Production taxes are set by state and local governments and vary as to the tax rate and the value to which that rate is applied. Ad valorem tax rates also vary widely. In Louisiana, where a substantial percentage of our production is derived, severance taxes are levied on a per Mcf basis. Therefore, the resulting dollar value of production is not sensitive to changes in prices for natural gas, except for holiday exemptions, if any. In our other operating areas, production taxes are predominantly price dependent.

In addition to our existing production and ad valorem taxes on current properties, we may be subject to new taxes or changes to existing rates in the future. The State of Louisiana, which raised its severance tax rate to

$0.33 per Mcf from $0.29 per Mcf effective July 1, 2009, decreased the rate to $0.164 per Mcf effective July 1, 2010. In addition, the Commonwealth of Pennsylvania has recently enacted legislation that budgets for revenue from the extraction of Marcellus shale natural gas with an effective date for implementation no later than January 1, 2011. However, the state legislature has not yet agreed on the funding mechanism.

Overall, our production and ad valorem tax rates per Mcfe were $0.21 per Mcfe for 2010, $0.30 per Mcfe for the year ended December 31, 2009 and $0.53 per Mcfe for the year ended December 31, 2008. The following tables present our severance and ad valorem taxes on a per Mcfe basis and percentage of revenue basis for our significant producing regions.

	Year ended December 31,									
	2010					2009				
(in thousands, except per unit rate)	Revenue	Production (Mmcfe)	Severance and ad valorem taxes	Taxes % of revenue	Taxes $/Mcfe	Revenue	Production (Mmcfe)	Severance and ad valorem taxes	Taxes % of revenue	Taxes $/Mcfe
Producing region:										
East Texas/North										
Louisiana	$397,680	95,423	$16,914	4.3%	$0.18	$ 315,710	82,138	$24,162	7.7%	$0.29
Appalachia	45,962	9,427	1,740	3.8%	0.18	91,832	19,184	2,562	2.8%	0.13
Permian and other	71,584	7,156	5,385	7.5%	0.75	58,784	8,827	5,658	9.6%	0.64
Mid-Continent	—	—	—	—	—	84,179	18,013	6,588	7.8%	0.37
Total	$515,226	112,006	$24,039	4.7%	0.21	$ 550,505	128,162	$38,970	7.1%	0.30

	Year ended December 31,									
	2009					2008				
(in thousands, except per unit rate)	Revenue	Production (Mmcfe)	Severance and ad valorem taxes	Taxes % of revenue	Taxes $/Mcfe	Revenue	Production (Mmcfe)	Severance and ad valorem taxes	Taxes % of revenue	Taxes $/Mcfe
Producing region:										
East Texas/North										
Louisiana	$315,710	82,138	$24,162	7.7%	$0.29	$ 802,579	87,540	$40,227	5.0%	$0.46
Appalachia	91,832	19,184	2,562	2.8%	0.13	209,221	20,899	5,545	2.7%	0.27
Permian and other	58,784	8,827	5,658	9.6%	0.64	149,878	11,897	12,712	8.5%	1.07
Mid-Continent	84,179	18,013	6,588	7.8%	0.37	243,148	24,239	18,415	7.6%	0.76
Total	$550,505	128,162	$38,970	7.1%	0.30	$1,404,826	144,575	$76,899	5.5%	0.53

Depreciation, depletion and amortization

The following table presents our depreciation, depletion and amortization expenses for the years ended December 31, 2010, 2009 and 2008. The depreciation, depletion and amortization rate per Mcfe produced varies significantly for each of the periods presented due to the various divestitures, acquisitions and ceiling test write-downs. The depreciation, depletion and amortization rate for the year ended December 31, 2010 was $1.75, a $0.03 increase from the year ended December 31, 2009. The increase was a result of increased drilling on proved undeveloped locations in the Haynesville area, offset by a decrease in depreciation related to the mid-year 2009 sale of our East Texas/North Louisiana gathering assets to our equity investment TGGT. The depreciation, depletion and amortization rate for the year ended December 31, 2009 was $1.72, a $1.46 decrease from year ended December 31, 2008. The decrease was a result of the first quarter 2009 $1.3 billion ceiling test write-down and the divestitures during 2009.

(in thousands)	Year ended December 31, 2010	2009	2008	Year to year change 2010-2009	Year to year change 2009-2008
Depreciation, depletion and amortization costs:					
Depletion expense	$179,613	$196,515	$435,595	$(16,902)	$(239,080)
Depreciation and amortization expense	$ 17,350	$ 24,923	$ 24,719	$ (7,573)	$ 204
Depletion calculated rate per Mmcfe	$ 1.60	$ 1.53	$ 3.01	$ 0.07	$ (1.48)
Depreciation and amortization calculated rate per Mmcfe	$ 0.15	$ 0.19	$ 0.17	$ (0.04)	$ 0.02
Consolidated depreciation, depletion and amortization rate per Mcfe	$ 1.75	$ 1.72	$ 3.18	$ 0.03	$ (1.46)

Accretion of discount on asset retirement obligations decreased to $3.8 million in 2010 from $7.1 million in 2009 and $6.7 million in 2008. The decrease in 2010 from 2009 reflects the 2009 Divestitures and the Appalachia JV in 2010. The increase in 2009 from 2008 is due to the combination of significant well additions and related plugging liabilities in connection with our 2008 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. The impact of our 2009 Divestitures on accretion expense was not significant to 2009 as the divestitures occurred throughout the year.

Write-down of oil and natural gas properties

For the year ended December 31, 2009, we recognized a ceiling test write-down of $1.3 billion to our oil and natural gas properties. For the year ended December 31, 2008, we recognized ceiling test write-downs of $2.8 billion to our proved oil and natural gas properties. There were no ceiling test write-downs in 2010.

General and administrative expenses

The following table presents our general and administrative expenses for the years ended December 31, 2010, 2009 and 2008 and changes for each of the years then ended.

	Year ended December 31,			Year to year change	Year to year change
(in thousands)	**2010**	**2009**	**2008**	**2010-2009**	**2009-2008**
General and administrative costs:					
Gross general and administrative expense	$134,733	$137,038	$123,981	$(2,305)	$13,057
Operator overhead reimbursements	(16,176)	(24,600)	(24,902)	8,424	302
Capitalized acquisition and development charges	(13,443)	(13,261)	(11,511)	(182)	(1,750)
Net general and administrative expense	$105,114	$ 99,177	$ 87,568	$ 5,937	$11,609
General and administrative expense per Mcfe	$ 0.94	$ 0.77	$ 0.61	$ 0.17	$ 0.16

Our general and administrative costs for the twelve months ended December 31, 2010 were $105.1 million, or $0.94 per Mcfe, compared to $99.2 million, or $0.77 per Mcfe, for the same period in 2009, an increase of $5.9 million, or 6.0%.

Significant components of the overall increase include the following items:

- increased salaries and benefit costs of $7.8 million due primarily to technical employees hired to exploit our shale resource asset base;
- increased legal costs of $5.3 million due to various claims and settlements;
- increased building rent and fees of $2.7 million due to expansion of our Dallas office;
- increased travel costs of $1.9 million primarily related to joint venture activities; and
- decreases in operator overhead recoveries of $8.4 million due to the 2009 Divestitures.

These increases were partially offset by recoveries of technical and administrative service costs of $18.6 million from our service agreement with BG Group, a $0.4 million decrease in share-based compensation due to a reduction in options granted in 2010 compared to prior years and a $1.0 million reduction in bad debt expense.

Net general and administrative expenses for the year ended December 31, 2009 were $99.2 million, or $0.77 per Mcfe, compared with $87.6 million, or $0.61 per Mcfe, in 2008, an increase of $11.6 million.

The primary components of the net increase of $11.6 million for the year ended December 31, 2009 were higher personnel costs of $16.4 million due to additional employees related to expansion of technical staff to exploit our shale resource asset base, $2.6 million in employee relocation and severance costs associated with our divestitures and office closures, $4.4 million in additional stock compensation expense related primarily to the acceleration of vesting of certain employees impacted by the divestitures, the impact that the increase in our stock price had on the valuation of our December 2009 grants compared to the December 2008 grants and increased rent of $1.6 million resulting from our 2008 expansion.

These increases were offset by the following items:

- decreased legal fees of $4.4 million due to the first quarter 2008 cancellation of a proposed master limited partnership and reduced reserves for claims;
- decreased franchise and property taxes of $1.5 million due primarily to lower equity as a result of 2008 and 2009 ceiling test write-downs and recapitalization of our corporate structure;
- decreased information and technology costs of $1.6 million due primarily to prior year costs incurred in connection with additional personnel;
- recovery of $4.6 million of technical service costs from our service agreement with BG Group; and
- increased capitalized salary costs of $1.8 million due to the previously discussed expansion of technical personnel.

Gain on divestitures and other operating items

In 2010, we recognized a gain on the Appalachia JV of $528.9 million, after a reduction for estimated post-closing adjustments of $45.0 million in the fourth quarter of 2010. This gain was offset by the incurrence of operating expense items which we do not directly attribute to direct lease operating costs or normal general and administrative costs. Examples of these costs in 2010 include professional fees incurred by a special committee of our board of directors to evaluate strategic opportunities, valuation allowances to the carrying costs or losses from sales of our field inventory items, conventional rig contract terminations and certain legal costs. In 2009, we recognized gains of $691.9 million, which were also reduced by similar operating expense items described above. The 2008 items were not material.

Interest expense

Our interest expense for the year ended December 31, 2010 was $45.5 million compared to $147.2 million for the same period in 2009. The decrease is primarily due to the $56.6 million decrease in interest and deferred financing costs related to the $300.0 million senior unsecured term credit agreement, or the Term Credit Agreement, which was paid off on August 14, 2009, along with lower average balances on our credit agreement, a $7.1 million decrease related to the redemption of our the 2011 Notes, a $4.3 million decrease related to the final settlement on our interest rate swaps and a $15.0 million increase in capitalized interest. These decreases were partially offset by $16.7 million in interest expense on the 2018 Notes and $0.5 million related amortization of deferred financing costs.

Interest expense for the year ended December 31, 2009 was $147.2 million compared to $161.6 million for the same period in 2008. The decreased interest expense of $14.5 million is a result of $46.1 million decreased interest costs from our credit agreement due to the combination of significant reductions in outstanding debt beginning in the third quarter of 2009 and lower LIBO rates in 2009 compared to 2008, a $5.0 million decrease related to our interest rate swaps and a $2.0 million decrease related to a full year of capitalized interest. The decrease was offset by an increase of $9.0 million resulting primarily from the write-off of deferred financing fees related to the reduction of our debt on the credit agreement and $29.7 million of interest and deferred financing costs related to the Term Credit Agreement, which included a $15.0 million duration fee.

(in thousands)	Year ended December 31, 2010	2009	2008	Year to year change 2010-2009	Year to year change 2009-2008
Interest expense:					
2011 Notes(1)	$ 21,532	$ 28,653	$ 28,874	$ (7,121)	$ (221)
2018 Notes	16,700	—	—	16,700	—
EXCO Resources Credit Agreement	12,609	22,778	42,628	(10,169)	(19,850)
EXCO Operating credit agreement(2)	6,008	26,456	52,717	(20,448)	(26,261)
Term Credit Agreement	—	18,833	13,337	(18,833)	5,496
Amortization of deferred financing costs on EXCO Resources Credit Agreement	3,740	8,632	1,956	(4,892)	6,676
Amortization of deferred financing costs on EXCO Operating credit agreement(2)	4,436	5,362	3,014	(926)	2,348
Amortization of deferred financing costs on Term Credit Agreement	—	37,754	13,598	(37,754)	24,156
Amortization of deferred financing costs on 2018 Notes	537	—	—	537	—
Interest rate swaps settlements	2,063	12,180	(588)	(10,117)	12,768
Fair market value adjustment on interest rate swaps	(2,018)	(7,861)	9,878	5,843	(17,739)
Capitalized interest	(20,829)	(5,840)	(3,861)	(14,989)	(1,979)
Other interest expense	755	214	85	541	129
Total interest expense	$ 45,533	$147,161	$161,638	$(101,628)	$(14,477)

(1) We issued the 2018 Notes on September 15, 2010 and used a portion of the proceeds to redeem the 2011 Notes on October 15, 2010.

(2) On April 30, 2010, the EXCO Operating credit agreement was consolidated into the EXCO Resources Credit Agreement.

Derivative financial instruments

Our objective in entering into derivative financial instruments is to manage our exposure to commodity price and interest rate fluctuations, protect our returns on investments, and achieve a more predictable cash flow from operations. 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. 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.

The following table presents our realized and unrealized gains and losses from our oil and natural gas derivative financial instruments. Our derivative activity is reported as a component of other income or expenses in our consolidated statements of operations.

(in thousands)	Year ended December 31, 2010	2009	2008	Year to year change 2010-2009	Year to year change 2009-2008
Derivative financial instrument activities:					
Cash settlements on derivative financial instruments, excluding early terminations	$179,519	$ 478,463	$(109,300)	$(298,944)	$ 587,763
Cash settlements on early terminations of derivative financial instruments	37,936	—	—	37,936	—
Non-cash change in fair value of derivative financial instruments	(70,939)	(246,438)	493,689	175,499	(740,127)
Total derivative financial instrument activities	$146,516	$ 232,025	$ 384,389	$ (85,509)	$(152,364)

The use of derivative financial instruments allows us to limit the impacts of volatile price fluctuations associated with oil and natural gas. The following table presents our natural gas prices, before the impact of derivative financial instruments, where average realized prices per Mcfe increased from $4.30 for the year ended December 31, 2009 to $4.60 during the year ended December 31, 2010. Excluding the impact of the cash settlement on early terminations of certain derivatives, average realized prices per Mcfe after the impact of our derivative financial instruments decreased our price from $8.03 to $6.20 per Mcfe during the year ended December 31, 2010 and decreased our price from $8.96 to $8.03 per Mcfe during the year ended December 31, 2009.

	Year ended December 31, 2010	2009	2008	Year to year change 2010-2009	Year to year change 2009-2008
Realized pricing:					
Oil per Bbl	$76.18	$53.72	$96.93	$22.46	$(43.21)
Natural gas per Mcf	4.29	3.93	9.06	0.36	(5.13)
Natural gas equivalent per Mcfe	$ 4.60	$ 4.30	$ 9.72	$ 0.30	$ (5.42)
Cash settlements on derivative financial instruments, excluding early terminations	1.60	3.73	(0.76)	(2.13)	4.49
Net price per Mcfe, including derivative financial instruments before early terminations	6.20	8.03	8.96	(1.83)	(0.93)
Cash settlements on early terminations of derivative financial instruments	0.34	—	—	0.34	—
Net price per Mcfe, derivative financial instruments	$ 6.54	$ 8.03	$ 8.96	$ (1.49)	$ (0.93)

Our total cash settlements for 2010 increased our other income by $217.5 million, or $1.94 per Mcfe compared to cash settlements increasing our other income by $478.5 million, or $3.73 per Mcfe, in 2009. Our cash settlements decreased our other income by $109.3 million, or $0.76 per Mcfe, in 2008. As noted above, the significant fluctuations between settlements of receipts on our derivative financial instruments demonstrate the aforementioned volatility in prices.

Our non-cash mark-to-market changes in the value of our oil and natural gas derivative financial instruments for the year ended December 31, 2010 resulted in a loss of $70.9 million compared to a loss of $246.4 million and a gain of $493.7 million for the years ended December 31, 2009 and 2008, respectively. 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 January 2008, we entered into interest rate swaps to mitigate our exposure to fluctuations in interest rates on $700.0 million in principal through February 14, 2010 at LIBO rates ranging from 2.45% to 2.8%. For the year ended December 31,2010, we had realized losses from settlements of $2.1 million. These swaps expired on February 14, 2010 and as of December 31, 2010 we have not entered into any new interest rate swaps. For the year ended December 31, 2009, we had realized losses from settlements of $12.2 million and $2.0 million of cumulative non-cash unrealized losses attributable to our interest rate swaps. For the year ended December 31, 2008, we had realized gains from settlements of $0.6 million and $9.9 million of non-cash unrealized losses attributable to our interest rate swaps.

Income taxes

The following table presents a reconciliation of our income tax provision (benefit) for the years ended December 31, 2010, 2009 and 2008.

	Year ended December 31,		
(in thousands)	**2010**	**2009**	**2008**
United States federal income taxes (benefit) at statutory rate of 35%	$ 235,737	$(177,207)	$(695,977)
Increases (reductions) resulting from:			
Goodwill	11,556	43,455	—
Adjustments to the valuation allowance	(277,182)	141,975	526,372
Non-deductible compensation	2,098	2,808	2,321
State taxes net of federal benefit	29,050	(20,606)	(88,266)
Other	349	74	517
Total income tax provision	$ 1,608	$ (9,501)	$(255,033)

During 2010, our income tax rate was impacted by an increase in income that resulted in utilization of net operating losses that was further adjusted by the release of valuation allowances against deferred tax assets. The net result is a current alternative minimum tax and state income tax liability related to divestitures of properties.

During 2009, our income tax rate was impacted by the recognition of valuation allowances against deferred tax assets, which were primarily due to ceiling test write-downs that caused previous book basis and tax basis differences to change from deferred tax liabilities to deferred tax assets and divestitures of properties.

During 2008, our income tax rate was impacted by the establishment of valuation allowances against deferred tax assets, which were primarily due to ceiling test write-downs that caused previous book basis and tax basis differences to change from deferred tax liabilities to deferred tax assets. Our deferred tax assets were offset by valuation allowances after testing to determine if the asset would meet a more likely than not criteria for realization pursuant to FASB ASC Topic 740—Income Taxes.

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

The Company adopted the provisions of FASB ASC Subtopic 740-10 Accounting for Income Taxes on January 1, 2007. As a result of ASC Subtopic 740-10, the Company recognized zero liabilities for unrecognized tax benefits. As of December 31, 2010, 2009 and 2008, the Company's policy is to recognize interest related to unrecognized tax benefits of interest expense and penalties in operating expenses. The Company has not accrued any interest or penalties relating to unrecognized tax benefits in the current financials.

Our liquidity, capital resources and capital commitments

Overview

Our primary sources of capital resources and liquidity are internally generated cash flows from operations, borrowing capacity under the EXCO Resources Credit Agreement, dispositions of non-strategic assets, joint ventures and capital markets, when market conditions are favorable. Prior to our increased emphasis on horizontal drilling in our shale resource plays, we targeted funding our drilling and development capital spending programs within cash flows from operations. However, capital expenditure requirements to develop the Haynesville/Bossier shale, Marcellus shale and related midstream infrastructures are significant. While we expect our shale development programs to contribute significant reserve additions and production volumes, the required development capital to achieve these results are expected to exceed internally generated cash flow in 2011. Continued volatility in natural gas prices may also alter our development plans in 2011 and 2012.

Other factors which are expected to or could impact our liquidity, capital resources and capital commitments in 2011 include the following:

- the utilization of the remaining balance of the East Texas/North Louisiana Carry in the first quarter;
- the results of our appraisal and exploration programs in the Marcellus shale;
- an extended period of low natural gas prices;
- decisions by BG Group not to participate for their 50% share in acquisitions we made intended for either the East Texas/North Louisiana JV or the Appalachia JV;
- excessive time lags in receiving reimbursements from BG Group related to purchases for their 50% share in property acquisitions in which they elect to participate;
- continued expansion of our technical personnel required to support our drilling programs, particularly in Appalachia;
- decreases in the percentage of our production covered by derivative financial instruments, coupled with expiration of higher priced derivative financial instruments;
- acquisitions of unproved or undeveloped oil and natural gas properties with little or no current cash flows; and
- continued upward trends in service costs related to horizontal drilling and completions.

Each of the aforementioned factors impact our near-term liquidity and we expect that we will be required to draw on our EXCO Resources Credit Agreement or seek other sources of capital to fund our operations.

Acquisitions are generally not budgeted as they tend to be opportunity driven and our current strategy is to limit acquisition activity to our target areas (East Texas/North Louisiana and Appalachia) for contiguous acreage blocks or “bolt-on” acreage, as economic conditions permit.

Our capital budget for 2011 totals $976.2 million and reflects our focus on the development of our Haynesville and Bossier shale plays in East Texas/North Louisiana and an increased emphasis in the Marcellus shale in Appalachia. The East Texas/North Louisiana JV and the Appalachia JV reduced our ownership interests in these properties by 50%. The joint ventures each provided for BG Group to fund 75% of our share of drilling and development costs on horizontal wells, up to specified dollar limits, which have provided, and continue to provide us with substantial economic benefit toward development of these shale resources. As of January 31, 2011, the unused East Texas/North Louisiana Carry was approximately $8.0 million, while $124.8 million of the Appalachia Carry remained unused.

The following table presents our liquidity and financial position as of December 31, 2010 and February 17, 2011:

(in thousands)	December 31, 2010	February 17, 2011
Cash(1)	$ 205,946	$ 181,009
Drawings under the EXCO Resources Credit Agreement	$ 849,000	$ 549,000
2018 Notes(2)	750,000	750,000
Total debt	1,599,000	1,299,000
Net debt	$1,393,054	$1,117,991
Borrowing base	$1,000,000	$1,000,000
Total of unused borrowing base(3)	$ 135,498	$ 435,498
Unused borrowing base plus cash(1)(3)	$ 341,444	$ 616,507

(1) Includes restricted cash of $161.7 million at December 31, 2010 and $166.0 million at February 17, 2011.

(2) Excludes unamortized bond discount of $10.7 million at December 31, 2010 and $10.6 million at February 17, 2011.

(3) Net of letters of credit of $15.5 million at December 31, 2010 and at February 17, 2011.

Recent events affecting liquidity

On January 31, 2011, TGGT closed the TGGT Credit Agreement. Use of proceeds of the initial draw under the TGGT Credit Agreement included a distribution to EXCO and BG Group of $125.0 million each. We used the distribution to reduce the borrowings under the EXCO Resources Credit Agreement. The TGGT Credit Agreement, of which an affiliate of BG Group is a 50% lender, matures on January 31, 2016 and is collateralized by first lien mortgages on substantially all of the real and personal property of TGGT, including all of the equity interests of TGGT's subsidiaries. The equity interests of TGGT held by EXCO and BG Group are not pledged and neither EXCO or BG Group are providing any guarantees or other credit support to the lenders. We expect the TGGT Credit Agreement, together with their cash flows from operations, will be sufficient to fund their 2011 capital expenditure programs, which will provide us with additional liquidity to fund our upstream operations.

During the fourth quarter of 2010, we entered into two transactions which will significantly expand our presence in the Appalachia region. On December 15, 2010, we funded an escrow account for the Chief Transaction for approximately $459.4 million, subject to receipt of consents from a third party, post-closing adjustments and completion of title diligence. At the time of acquisition, the properties were producing 22 Mmcf per day from 15 wells and 11 wells were awaiting completion. The Chief Transaction includes approximately 56,000 net acres prospective for the Marcellus shale development. On January 11, 2011, the necessary consents from the third party were received and escrow funds were released. On February 7, 2011, BG Group funded $229.7 million to acquire their 50% share of the Chief Transaction. In addition, we entered into a purchase and sale agreement to purchase additional Marcellus shale prospective acreage and shallow wells which hold the Marcellus deep rights from a private producer for $95.0 million, subject to further due diligence and post-closing adjustments. We anticipate that BG Group will participate in 50% of this acquisition.

On October 6, 2010, the lenders under the EXCO Resources Credit Agreement completed their regular semi-annual redetermination of our borrowing base, establishing a borrowing base of $1.0 billion, as requested by EXCO following the offering of the 2018 Notes. The next redetermination of the borrowing base is scheduled to occur on April 1, 2011.

On September 15, 2010, we issued the 2018 Notes. Net proceeds, after an original issue discount, commissions and fees and expenses were $724.1 million, a portion of which were used to redeem all $444.7 million principal amount and accrued interest of the 2011 Notes and to reduce the balance outstanding under the EXCO Resources Credit Agreement. As of result of the offering, current maturities of debt were extended to 2018 and availability under our credit agreement at September 30, 2010 was increased.

On July 19, 2010, we announced a stock repurchase program whereby we are permitted, but not required, to repurchase up to $200.0 million of our common stock in open market transactions, privately negotiated transactions or through a structured share repurchase program. Funds for the share repurchases will be from available cash or from availability under the EXCO Resources Credit Agreement. As of February 17, 2011, we have purchased 539,221 shares of our common stock at an aggregate cost of $7.5 million. The program is currently suspended as a result of the pending strategic alternatives being evaluated by a special committee of our Board of Directors in connection with a proposal from our Chairman and Chief Executive Officer to purchase all of our outstanding common stock which he does not already own.

We closed the Appalachia JV on June 1, 2010 with BG Group, which resulted in net proceeds of approximately $790.2 million, after a reduction of $45.0 million for estimated post-closing adjustments. The net proceeds from the Appalachia JV are subject to further adjustments, whether upward or downward, as we have not finalized the post-closing process. We expect to finalize all post-closing matters during 2011. We used the proceeds to reduce the outstanding balance on the EXCO Resources Credit Agreement and fund working capital to OPCO. We expect that near-term impacts from the Appalachia JV to our capital resources and liquidity will include the following:

- A reduction in net operating cash flow reflecting the sale of 50% of our interest to BG Group in the existing shallow production of approximately 17.9 Mmcfe per day;
- Increased drilling and development activities, which presently include an expected increase in horizontal drilling from two rigs as of December 31, 2010 to an average of four during calendar 2011;
- Decreases in our net share of Marcellus drilling and completion costs on a per well basis arising from the Appalachia Carry; and
- Increases in midstream capital expenditures to construct our 50% share of gathering systems, pipelines and other midstream infrastructure to support significant increases in future production from the Marcellus shale play.

On June 30, 2010, EXCO and BG Group jointly closed the Southwestern Transaction consisting of oil and natural gas properties in Shelby, San Augustine and Nacogdoches Counties, Texas from Southwestern Energy Company, or the Southwestern Transaction. The purchase price was $357.8 million ($178.9 million net to EXCO), after post-closing purchase price adjustments. Our net acquisition price was financed with borrowings under the EXCO Resources Credit Agreement. The development of these assets is governed by the East Texas/North Louisiana JV. The majority of the assets acquired in the Southwestern Transaction represent incremental working interests in properties that EXCO and BG Group acquired in the Common Transaction.

On May 14, 2010, EXCO and BG Group closed the joint purchase of the Common Transaction, which owned properties in Shelby, San Augustine and Nacogdoches Counties, Texas in the Haynesville and Bossier shales. The purchase price was approximately $442.1 million ($221.0 million net to EXCO), after post-closing purchase price adjustments. Our net acquisition price was financed with borrowings under the EXCO Resources Credit Agreement. The development of these assets is governed by the East Texas/North Louisiana JV.

Although recent financial reform legislation may negatively affect our capital and credit markets, and continued weakness in commodity prices, particularly natural gas, we believe that our capital resources from existing cash balances, anticipated cash flow from operating activities and available borrowing capacity under our credit agreement are adequate to execute our corporate strategies and to meet debt service obligations. Our future cash flows from operations are subject to a number of variables, including production volumes, oil and natural gas prices and drilling and service costs. The effectiveness of our derivative financial instruments and our ability to enter into additional derivative financial instruments may also impact our future cash flows. While we continue to evaluate opportunities to enter into derivative financial instruments, our recent percentage of expected production covered by derivative financial instruments has decreased compared to previous years.

Historical sources and uses of funds

Net increases (decreases) in cash are summarized as follows:

(amounts in thousands)	Year ended December 31, 2010	2009	2008
Cash flows provided by operating activities	$ 339,921	$ 433,605	$ 974,966
Cash flows provided by (used in) investing activities	(712,854)	1,235,275	(1,708,579)
Cash flows provided by (used in) financing activities	348,755	(1,657,612)	735,242
Net increase (decrease) in cash	$ (24,178)	$ 11,268	$ 1,629

Our primary sources of cash in 2010 were proceeds from our Appalachia JV and other assets sales, proceeds from the issuance of the 2018 Notes and cash flows from operating activities. We utilized these cash inflows to redeem our 2011 Notes, fund our drilling and development activities and close acquisitions. As of December 31, 2010, our total unrestricted and restricted cash was $205.9 million compared with $127.3 million as of December 21, 2009. Our consolidated debt was $1.6 billion as of December 31, 2010 compared with $1.2 billion as of December 31, 2009. The December 31, 2010 balance includes $459.4 million of borrowings to fund the Chief Transaction. On February 7, 2011, we received $229.7 million from BG Group for their share of this acquisition. As of February 17, 2011, our consolidated debt was reduced to $1.3 billion due primarily to BG Group reimbursements for acquisitions and the TGGT cash distribution.

In 2009, our primary sources of cash were from the East Texas/North Louisiana JV and TGGT transactions, the 2009 Divestitures and cash flows from operating activities, which together provided approximately $2.5 billion in cash. These cash sources, which were offset by uses of approximately $711.8 million in drilling and development and midstream equity investments, contributed to a reduction to our debt of over $2.1 billion.

Cash flows from operations

The primary factors impacting our cash flows from operations generally include: (i) levels of production from our oil and natural gas properties, (ii) prices we receive from sales of oil and natural gas production, including settlement proceeds or payments related to our oil and natural gas derivatives, (iii) operating costs of our oil and natural gas properties, (iv) costs of our general and administrative activities and (v) interest expense and other financing related costs in 2010. Our cash flows from operations have been significantly impacted by fluctuations in oil and natural gas prices and our production volumes. Our production volumes in 2010 were negatively impacted by the 2009 Divestitures, the East Texas/North Louisiana JV in August 2009 and the Appalachia JV in June 2010. For the month of December 2008, prior to the 2009 Divestitures and joint venture transactions with BG Group, our production averaged 407 Mmcfe per day. Due to the success of our Haynesville shale drilling program, we have made significant progress towards replenishing these volumes, which averaged 374 Mmcfe per day for the month of December 2010. Prices of oil and natural gas have historically been, and continue to be, volatile. We use derivative financial instruments to help mitigate this price volatility.

Net cash provided by operating activities was $339.9 million for the year ended December 31, 2010 compared with $433.6 million for the year ended December 31, 2009. The 21.6% decrease is attributable primarily to lower production volumes resulting from the 2009 Divestitures and East Texas/North Louisiana JV and lower cash settlements of our oil and natural gas derivatives. These decreases were partially offset by higher average oil and natural gas prices during 2010 compared with average prices during the same period in 2009. At February 17, 2010, our cash and cash equivalents balance was $15.0 million and our restricted cash account, which is principally used for Haynesville development operations, was $166.0 million.

Investing activities

Our investing activities consist primarily of drilling and development expenditures, capital contributions to our jointly-owned midstream ventures, and acquisitions, including prospective acreage acquisitions in our target areas. Our recent acquisitions have been focused primarily on undeveloped shale acreage in our core areas and have been funded primarily with borrowings under our credit agreement. We also receive reimbursements from BG Group on these acquisitions as they elect to participate. Future acquisitions are dependent on oil and natural gas prices, availability of attractive acreage and availability of borrowing capacity under our credit agreement.

Acquisitions and capital expenditures

The following table presents our capital expenditures for the years ended December 31, 2010, 2009 and 2008. The 2010 capital expenditures do not include the $459.4 million we funded for the Chief Transaction as the necessary consents to release funds from escrow were not received from third parties until January 11, 2011.

	Year ended December 31,		
(in thousands)	2010	2009	2008
Capital expenditures:			
Oil and natural gas property acquisitions(1)	$ 533,941	$233,634	$ 700,174
Midstream acquisitions	—	—	66,172
Lease purchases(2)	95,843	106,040	187,134
Development capital expenditures	346,582	299,837	693,173
Midstream capital additions	—	53,122	54,993
Seismic	21,335	12,400	15,833
Gas gathering and water pipelines	23,607	1,176	4,862
Corporate and other	74,427	38,957	33,139
Total capital expenditures	$1,095,735	$745,166	$1,755,480

(1) 2010 acquisitions include the Common Transaction and Southwestern Transaction.

(2) Excludes reimbursements from BG Group of $58.3 million in 2010.

Our acquisitions in 2010 and 2009 emphasized expansion of undeveloped acreage portfolios in the Haynesville and Bossier shales in East Texas/North Louisiana and the Marcellus shale in Appalachia.

During 2008, we completed acquisitions of conventional oil and natural gas producing assets, undeveloped locations and other oil and natural gas assets totaling $766.3 million.

We commenced our shift in strategy by focusing on undeveloped acreage in East Texas/North Louisiana and Appalachia to exploit the Haynesville and Marcellus shales. In Appalachia, most of our existing shallow production areas and newly acquired leasehold interests hold deep rights in the Marcellus shale formation. Similarly, in East Texas/North Louisiana, our existing production areas and newly acquired leasehold interests hold deep rights in the Haynesville/Bossier shale play. We spent approximately $64.9 million in the Haynesville/Bossier shale plays in East Texas/North Louisiana and approximately $92.1 million in the Marcellus shale play in the Appalachia region of the United States during 2008.

Future capital expenditures are subject to a number of variables including our oil and natural gas production volumes, fluctuations in oil and natural gas prices, availability of borrowings under our credit agreement and ability to service our debt. If our cash flows decline from current levels, we may be required to reduce our capital expenditure budget, which in turn may affect our production in future periods. Continued weakness in natural gas prices, expiration of our higher priced derivative financial instruments and projected increased capital expenditures in 2011 will likely require increased borrowing under the EXCO Resources Credit Agreement to meet our present production targets.

2011 Capital budget

Our capital budget for 2011 will continue to emphasize development of our significant shale resources in the Haynesville/Bossier shale play in East Texas/North Louisiana, but also reflects a significant increase in appraisal and development of our Marcellus shale play acreage in Appalachia.

The budgeted 2011 capital expenditures for exploration and development activities total $976.2 million, which reflects utilization of $124.8 million of the Appalachia Carry. The East Texas/North Louisiana Carry covering drilling and development costs in the Haynesville/Bossier shales in East Texas/North Louisiana will be fully utilized during the first quarter of 2011 and we are now obligated to fund our 50% share of future activities in this area. The following table presents a comparison of our 2011 capital expenditure budget to our actual 2010 capital expenditures. The 2011 capital expenditures budget does not include any equity contributions to TGGT as we expect the capital programs to be funded from cash flows and available borrowing capacity under the TGGT Credit Agreement.

(in millions, except wells)	2011 planned gross wells	2011 capital budget	2010 actual spending	Year to year change
East Texas/North Louisiana	233	$781.8	$339.7	$442.1
Appalachia	68	82.8	106.8	(24.0)
Permian	72	53.4	40.9	12.5
Corporate and other	—	58.2	74.4	(16.2)
Total	373	$976.2	$561.8	$414.4

Credit agreement and long-term debt

As of February 17, 2011 we had total debt outstanding of approximately $1.3 billion consisting of borrowings under the EXCO Resources Credit Agreement of $549.0 million and $750.0 million of the 2018 Notes. Terms and conditions of each of the debt obligations are discussed below. On October 15, 2010, we redeemed our 2011 Notes. Funds to redeem the 2011 Notes were provided from net proceeds from issuance of the 2018 Notes. Our ability to borrow from sources other than the EXCO Resources Credit Agreement is subject to certain restrictions imposed by our lenders and the Indenture. These agreements contain limitations and restrictions on incurring additional indebtedness and pledging our assets.

EXCO Resources Credit Agreement

The EXCO Resources Credit Agreement has a current borrowing base of $1.0 billion. On February 17, 2011, we had $549.0 million of outstanding indebtedness and $435.5 million of available borrowing capacity under the EXCO Resources Credit Agreement. The majority of EXCO's subsidiaries are guarantors under the EXCO Resources Credit Agreement, except those subsidiaries which are jointly held with BG Group and one other subsidiary that is wholly owned by us. The EXCO Resources Credit Agreement permits certain investments, loans and advances to the unrestricted subsidiaries that are jointly held with BG Group. On July 19, 2010, the EXCO Resources Credit Agreement was amended to allow for stock repurchases of up to $200.0 million. On September 15, 2010, the agreement was further amended to permit the redemption of the 2011 Notes by issuance of our 2018 Notes.

Borrowings under the EXCO Resources Credit Agreement are collateralized by first lien mortgages providing a security interest of not less than 80% of the Engineered Value, as defined in the EXCO Resources Credit Agreement, in our oil and natural gas properties evaluated by the lenders for purposes of establishing our borrowing base. We are permitted to have derivative financial instruments covering no more than 100% of the forecasted production total Proved Reserves (as defined in the agreement) during the first two years of the forthcoming five year period, 90% of the forecasted production from total Proved Reserves for any month during the third year of the forthcoming five year period and 85% of the forecasted production from total Proved Reserves during the fourth and fifth year of the forthcoming five year period.

The EXCO Resources Credit Agreement sets forth the terms and conditions under which we are permitted to pay a cash dividend on our common stock. Pursuant to the amendment, we may declare and pay cash dividends on our common stock in an amount not to exceed $50.0 million in any four consecutive fiscal quarters, provided that as of each payment date and after giving effect to the dividend payment date, (i) no default has occurred and is continuing, (ii) we have at least 10% of our borrowing base available under the EXCO Resources Credit Agreement, and (iii) payment of such dividend is permitted under our 2018 Notes.

The interest rate ranges from LIBOR plus 200 basis points, or bps, to LIBOR plus 300 bps depending upon borrowing base usage. The facility also includes an Alternate Base Rate, or ABR, pricing alternative ranging from ABR plus 100 bps to ABR plus 200 bps depending upon borrowing base usage. Based on a one month LIBOR of 0.26% on February 17, 2011, we would incur an interest rate of 2.76% on any new indebtedness we may incur under the EXCO Resources Credit Agreement.

As of December 31, 2010, we were in compliance with the financial covenants contained in the EXCO Resources Credit Agreement, which require that we:

- maintain a consolidated current ratio (as defined in the agreement) of at least 1.0 to 1.0 as of the end of any fiscal quarter; and
- not permit our ratio of consolidated funded indebtedness (as defined in the agreement) to consolidated EBITDAX (as defined in the agreement) to be greater than 3.50 to 1.0 at the end of any fiscal quarter ending on or after March 31, 2010.

The foregoing description is not complete and is qualified in its entirety by the EXCO Resources Credit Agreement.

2018 Notes

On September 15, 2010 we closed an underwritten offering of $750.0 million aggregate principal amount of 7.5% senior unsecured notes maturing on September 15, 2018. We received proceeds of approximately $724.1 million from the offering after deducting an original issue discount of $11.0 million and commissions, estimated offering fees and expenses of $14.9 million. The remaining net proceeds from the offering were used to redeem the 2011 Notes with the balance of approximately $271.3 million being used to pay a portion of the outstanding balance under the EXCO Resources Credit Agreement. The notes are guaranteed on a senior unsecured basis by EXCO's consolidated subsidiaries, other than EXCO Water Resources, LLC and all of our jointly-held equity investments with BG Group. Our midstream equity investments with BG Group are designated as unrestricted subsidiaries under the Indenture governing the 2018 Notes.

As of December 31, 2010, $750.0 million in principal was outstanding on our 2018 Notes. The unamortized discount on the 2018 Notes at December 31, 2010 was $10.7 million. The estimated fair value of the 2018 Notes, based on quoted market prices, was $736.1 million on December 31, 2010.

Interest on the on the 2018 Notes is payable semi-annually in arrears on March 15 and September 15 of each year, beginning on March 15, 2011.

The Indenture governing the 2018 Notes contains covenants, which may limit our ability and the ability of our restricted subsidiaries to:

- incur or guarantee additional indebtedness;
- pay dividends on our capital stock (over $50.0 million per annum) or make other distributions or repurchase or redeem our capital stock;
- prepay, redeem or repurchase certain debt;
- make certain investments and loans;
- sell assets;
- incur liens on our assets;
- enter into transactions with affiliates;
- alter the businesses we conduct;
- enter into agreements restricting our subsidiaries' ability to pay dividends; and
- consolidate, merge or sell all or substantially all of our assets.

Other activities

On July 10, 2010, we announced a stock repurchase program whereby we are permitted, but not required, to repurchase up to $200.0 million of our common stock in open market transactions, in privately negotiated transactions or through a structured share repurchase program. Funds for the share repurchases will be from available cash or under our existing debt facilities. As of February 17, 2011, we have purchased 539,221 shares of our common stock at an aggregate cost of $7.5 million. The program is currently suspended as a result of the pending strategic alternatives being evaluated by a special committee of our Board of Directors in connection with a proposal from our Chairman and Chief Executive Officer to purchase all of our outstanding common stock that he does not already own.

Derivative financial instruments

We use oil and natural gas derivatives and financial risk management instruments to manage our exposure to commodity price and interest rate fluctuations. We do not designate these instruments as hedging instruments for financial accounting purposes and, accordingly, we recognize the change in the respective instruments' fair value currently in earnings, as a gain or loss on oil and natural gas derivatives and interest expense on financial risk management instruments.

Recent financial reform legislation has addressed derivative financial instruments, including the possibility of requiring the posting of cash collateral for certain derivative parties. The definitions and specific requirements of this legislation are yet to be defined and we cannot presently quantify the impact to us, if any.

Oil and natural gas derivatives

Our production is generally sold at prevailing market prices. However, we periodically enter into oil and natural gas 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 oil and natural gas derivative contracts is to mitigate the impact of price fluctuations and achieve a more predictable cash flow associated with our operations and related borrowings under the EXCO Resources Credit Agreement. These transactions limit our exposure to declines in prices, but also limit the benefits we would realize if oil and natural gas prices increase. As of January 31, 2011, we had derivative financial instrument contracts in place for the volumes and prices shown below:

(in thousands, except prices)	NYMEX gas volume - Mmbtu	Weighted average contract price per Mmbtu	NYMEX oil volume - Bbls	Weighted average contract price per Bbl
Swaps:				
Remainder Q1 2011	14,455	$5.28	89	$111.32
Q2 2011	22,295	5.28	136	111.32
Q3 2011	22,540	5.28	138	111.32
Q4 2011	22,540	5.28	138	111.32
2012	53,070	5.37	275	95.70
2013	5,475	5.99	—	—

Interest rate swaps

In January 2008, we entered into interest rate swaps to mitigate our exposure to fluctuations in interest rates on $700.0 million in principal of our credit agreement through February 14, 2010 at LIBOR ranging from 2.45% to 2.8%. Our interest rate swaps expired in February 2010 and we have not entered into any new agreements.

Off-balance sheet arrangements

We have no arrangements or any guarantees of off-balance sheet debt to third parties.

Contractual obligations and commercial commitments

The following table presents a summary of our contractual obligations at December 31, 2010:

	Payments due by period				
(in thousands)	Less than one year	One to three years	Three to five years	More than five years	Total
Long-term debt—2018 Notes(1)	$ —	$ —	$ —	$ 750,000	$ 750,000
Long-term debt—EXCO Resources Credit Agreement(2)	—	849,000	—	—	849,000
Firm transportation services(3)	58,762	177,788	177,174	474,399	888,123
Pending acquisitions(4)	90,250	—	—	—	90,250
Other fixed commitments(5)	115,315	160,294	25,552	7,791	308,952
Drilling contracts	88,500	51,935	28	—	140,463
Operating leases	7,251	13,014	10,251	1,120	31,636
Total contractual obligations	$360,078	$1,252,031	$213,005	$1,233,310	$3,058,424

(1) Our Senior Notes are due on September 15, 2018. The annual interest obligation is $56.3 million.

(2) The EXCO Resources Credit Agreement, as amended, matures on April 30, 2014.

(3) Firm transportation services reflect contracts whereby EXCO commits to transport a minimum quantity of natural gas on a shippers' pipeline. Whether or not EXCO delivers the minimum quantity, we pay the fees as if the quantities were delivered.

(4) On December 17, 2010, we signed an agreement to purchase properties in Appalachia for $95.0 million, with an expected closing date of March 1, 2011. At December 31, 2010, we paid a deposit of $4.8 million, which is classified as "Deposits on pending acquisitions" on the consolidated balance sheets. We anticipate that BG Group will participate in 50% of this acquisition.

(5) Other fixed commitments are primarily related to completion service contracts.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity price risk

Our objective in entering into derivative financial instruments is to manage our exposure to commodity price and interest rate 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 expense 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.

Pricing for oil and natural gas is volatile. We do not designate our derivative financial instruments as hedging instruments for financial accounting purposes and, as a result, we recognize the change in the respective instrument's fair value currently in earnings, with respect to commodity derivatives, gains or losses on derivative financial instruments and with respect to interest rate swaps, as interest expense on financial risk management instruments.

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 oil and natural gas derivatives:

(in thousands, except prices)	Volume Mmbtus/Bbls	Weighted average strike price per Mmbtu/Bbl	Fair value at January 31, 2011
Natural gas:			
Swaps:			
Remainder 2011	81,830	$ 5.28	$57,542
2012	53,070	5.37	20,436
2013	5,475	5.99	4,111
Total natural gas	140,375		82,089
Oil:			
Swaps:			
Remainder 2011	501	111.32	6,918
2012	275	95.70	(1,090)
Total oil	776		5,828
Total oil and natural gas and derivatives			$87,917

At January 31, 2011, the average forward NYMEX oil prices per Bbl for calendar year 2011 and 2012 were $96.69 and $99.77, respectively, and the average forward NYMEX natural gas prices per Mmbtu for calendar 2011 and 2012 were $4.56 and $4.98, respectively. Our reported earnings and assets or liabilities for derivative financial instruments will continue to be subject to significant fluctuations in value due to price volatility.

Realized gains or losses from the settlement of our oil and natural gas derivatives are recorded in our financial statements as increases or decreases in other income or loss. For example, using the oil swaps in place as of December 31, 2010 for 2011, if the settlement price exceeds the actual weighted average strike price of $111.32 per Bbl, then a reduction in other income (expense) would be recorded for the difference between the settlement price and $111.32 per Bbl, multiplied by the hedged volume of 501 Mbbls. Conversely, if the settlement price is less than $111.32 per Bbl, then an increase in other income (expense) would be recorded for the difference between the settlement price and $111.32 per Bbl, multiplied by the hedged volume of 501 Mbbls. For example, for a hedged volume of 501 Mbbls, if the settlement price is $112.32 per Bbl then other income (expense) would decrease by $0.5 million. Conversely, if the settlement price is $110.32 per Bbl, oil and natural gas revenue would increase by $0.5 million.

Interest rate risk

At December 31, 2010, our exposure to interest rate changes related primarily to borrowings under our credit agreement and interest earned on our short-term investments. The interest rate is fixed at 7.5% on the $750.0 million outstanding on our 2018 Notes. Interest is payable on borrowings under our credit agreement 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, 2010, we had $849.0 million in outstanding borrowings under our credit agreement. A 1% change in interest rates based on the variable borrowings as of December 31, 2010 would result in an increase or decrease in our interest costs of $8.5 million per year. The interest we pay on these borrowings is set periodically based upon market rates.

In January 2008, we entered into financial risk management instruments to mitigate our exposure to fluctuations in interest rates on $700.0 million in principal through February 14, 2010 at LIBO rates ranging from 2.45% to 2.8%. These swaps expired on February 14, 2010 and we have not entered into any new agreements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EXCO RESOURCES, INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Contents

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended). Our internal control over financial reporting is designed to provide reasonable assurance to management and our board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2010. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework.* Based on management's assessment, management believes that, as of December 31, 2010, our internal control over financial reporting is effective based on those criteria.

The effectiveness of EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2010 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which appears herein.

By: /s/ DOUGLAS H. MILLER
Title: Chief Executive Officer

By: /s/ STEPHEN F. SMITH
Title: President and Chief Financial Officer

Dallas, Texas
February 24, 2011

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders

EXCO Resources, Inc.:

We have audited EXCO Resources, Inc.'s (the Company) internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). EXCO Resources, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, EXCO Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of EXCO Resources, Inc. and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2010, and our report dated February 24, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
February 24, 2011

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders

EXCO Resources, Inc.:

We have audited the accompanying consolidated balance sheets of EXCO Resources, Inc. and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of EXCO Resources, Inc. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 24, 2011 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
February 24, 2011

EXCO Resources, Inc.

Consolidated balance sheets

(in thousands)	December 31, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 44,229	$ 68,407
Restricted cash	161,717	58,909
Accounts receivable, net:		
Oil and natural gas	80,740	56,485
Joint interest	104,358	47,104
Interest and other	35,594	10,832
Inventory	7,876	15,830
Derivative financial instruments	73,176	138,120
Other	12,770	6,401
Total current assets	520,460	402,088
Equity investments	379,001	216,987
Oil and natural gas properties (full cost accounting method):		
Unproved oil and natural gas properties and development costs not being amortized	599,409	492,882
Proved developed and undeveloped oil and natural gas properties	2,370,962	1,875,749
Accumulated depletion	(1,312,216)	(1,132,604)
Oil and natural gas properties, net	1,658,155	1,236,027
Gas gathering assets	157,929	180,506
Accumulated depreciation and amortization	(24,772)	(22,841)
Gas gathering assets, net	133,157	157,665
Office, field and other equipment, net	43,149	31,771
Deferred financing costs, net	30,704	7,602
Derivative financial instruments	23,722	34,677
Goodwill	218,256	269,656
Deposits on acquisitions	464,151	0
Other assets	6,665	2,421
Total assets	$ 3,477,420	$ 2,358,894

See accompanying notes.

EXCO Resources, Inc.

Consolidated balance sheets

(in thousands, except per share and share data)	December 31, 2010	December 31, 2009
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 152,999	$ 112,991
Revenues and royalties payable	108,830	79,356
Accrued interest payable	18,983	16,193
Current portion of asset retirement obligations	900	900
Income taxes payable	211	210
Derivative financial instruments	3,775	3,264
Total current liabilities	285,698	212,914
Long-term debt, net of current maturities	1,588,269	1,196,277
Deferred income taxes	0	0
Derivative financial instruments	4,200	11,688
Asset retirement obligations and other long-term liabilities	58,701	78,427
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.001 par value; 10,000,000 authorized shares; none issued and outstanding	0	0
Common stock, $0.001 par value; 350,000,000 authorized shares; 213,736,266 shares issued and 213,197,045 shares outstanding at December 31, 2010; 211,905,509 shares issued and outstanding at December 31, 2009	214	212
Additional paid-in capital	3,151,513	3,105,238
Accumulated deficit	(1,603,696)	(2,245,862)
Treasury stock, at cost; 539,221 shares at December 31, 2010	(7,479)	0
Total shareholders' equity	1,540,552	859,588
Total liabilities and shareholders' equity	$ 3,477,420	$ 2,358,894

See accompanying notes.

EXCO Resources, Inc.

Consolidated statements of operations

(in thousands, except per share data)	Year ended December 31, 2010	2009	2008
Revenues:			
Oil and natural gas	$ 515,226	$ 550,505	$ 1,404,826
Midstream	—	35,330	85,432
Total revenues	515,226	585,835	1,490,258
Costs and expenses:			
Oil and natural gas production	108,184	177,629	238,071
Midstream operating	—	35,580	82,797
Gathering and transportation	54,877	18,960	14,206
Depreciation, depletion and amortization	196,963	221,438	460,314
Write-down of oil and natural gas properties	0	1,293,579	2,815,835
Accretion of discount on asset retirement obligations	3,758	7,132	6,703
General and administrative	105,114	99,177	87,568
Gain on divestitures and other operating items	(509,872)	(676,434)	(2,692)
Total costs and expenses	(40,976)	1,177,061	3,702,802
Operating income (loss)	556,202	(591,226)	(2,212,544)
Other income (expense):			
Interest expense	(45,533)	(147,161)	(161,638)
Gain on derivative financial instruments	146,516	232,025	384,389
Equity income (loss)	16,022	(69)	—
Other income (expense)	327	126	1,289
Total other income (expense)	117,332	84,921	224,040
Income (loss) before income taxes	673,534	(506,305)	(1,988,504)
Income tax expense (benefit)	1,608	(9,501)	(255,033)
Net income (loss)	671,926	(496,804)	(1,733,471)
Preferred stock dividends	—	—	(76,997)
Net income (loss) available to common shareholders	$ 671,926	$ (496,804)	$(1,810,468)
Earnings (loss) per common share:			
Basic			
Net income (loss)	$ 3.16	$ (2.35)	$ (11.81)
Weighted average common shares outstanding	212,465	211,266	153,346
Diluted			
Net income (loss)	$ 3.11	$ (2.35)	$ (11.81)
Weighted average common and common equivalent shares outstanding	215,735	211,266	153,346

See accompanying notes.

EXCO Resources, Inc.

Consolidated statements of cash flows

(in thousands)	Year ended December 31, 2010	2009	2008
Operating Activities:			
Net income (loss)	$ 671,926	$ (496,804)	$(1,733,471)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Loss on sale of other assets	0	0	39
Depreciation, depletion and amortization	196,963	221,438	460,314
Stock option compensation expense	16,841	18,987	15,978
Accretion of discount on asset retirement obligations	3,758	7,132	6,703
Write-down of oil and natural gas properties	0	1,293,579	2,815,835
Gain on divestitures	(528,888)	(691,932)	0
(Income) loss from equity investments	(16,022)	69	0
Non-cash change in fair value of derivatives	68,921	238,577	(483,811)
Cash settlements of assumed derivatives	907	(182,952)	83,603
Deferred income taxes	0	(9,371)	(255,285)
Amortization of deferred financing costs, discount on the 2018 Notes and premium on the 2011 Notes	5,014	48,159	15,195
Effect of changes in:			
Accounts receivable	(136,417)	34,998	7,884
Other current assets	1,188	(2,325)	1,734
Accounts payable and other current liabilities	55,730	(45,950)	40,248
Net cash provided by operating activities	339,921	433,605	974,966
Investing Activities:			
Additions to oil and natural gas properties, gathering systems and equipment	(519,206)	(664,292)	(1,004,792)
Property acquisitions	(522,765)	(68,404)	(719,330)
Restricted cash	(102,808)	(58,909)	0
Deposits on acquisitions	(464,151)	0	0
Investment in equity investments	(143,740)	(47,500)	0
Proceeds from disposition of property and equipment	1,044,833	2,074,380	15,543
Advances to Appalachia JV	(5,017)	0	0
Net cash provided by (used in) investing activities	(712,854)	1,235,275	(1,708,579)
Financing Activities:			
Borrowings under credit agreements	2,072,399	247,799	1,700,136
Repayments under credit agreements	(1,970,963)	(2,067,671)	(776,200)
Proceeds from issuance of 2018 Notes	738,975	0	0
Repayment of 2011 Notes	(444,720)	0	0
Proceeds from issuance of common stock	23,024	10,361	14,777
Payment of preferred stock dividends	0	0	(82,831)
Payment of common stock dividends	(29,760)	(10,582)	0
Payment for common stock repurchased	(7,479)	0	0
Settlements of derivative financial instruments with a financing element	(907)	182,952	(83,603)
Deferred financing costs and other	(31,814)	(20,471)	(37,037)
Net cash provided by (used in) financing activities	348,755	(1,657,612)	735,242
Net increase (decrease) in cash	(24,178)	11,268	1,629
Cash at beginning of period	68,407	57,139	55,510
Cash at end of period	$ 44,229	$ 68,407	$ 57,139
Supplemental Cash Flow Information:			
Cash interest payments	$ 54,523	$ 112,560	$ 134,087
Income tax payments	$ 5,460	$ 0	$ 0
Supplemental non-cash investing and financing activities:			
Capitalized stock option compensation	$ 6,351	$ 5,066	$ 4,060
Capitalized interest	$ 20,829	$ 5,840	$ 3,861
Issuance of common stock for director services	$ 61	$ 59	$ 137

See accompanying notes.

EXCO Resources, Inc.

Consolidated statements of changes in shareholders' equity

(in thousands)	Common stock Shares	Common stock Amount	Treasury stock Shares	Treasury stock Amount	Additional paid-in capital	Retained earnings (deficit)	Total shareholders' equity
Balance at December 31, 2007	104,579	$105	0	$ 0	$1,043,645	$ 71,992	$ 1,115,742
Issuance of common stock	1,127	1			14,913		14,914
Preferred stock dividends						(76,997)	(76,997)
Conversion of preferred stock	105,263	105			1,992,170		1,992,275
Share-based compensation					20,038		20,038
Net loss						(1,733,471)	(1,733,471)
Balance at December 31, 2008	210,969	$211	0	$ 0	$3,070,766	$(1,738,476)	$ 1,332,501
Issuance of common stock	936	1			10,419		10,420
Share-based compensation					24,053		24,053
Common stock dividends						(10,582)	(10,582)
Net loss						(496,804)	(496,804)
Balance at December 31, 2009	211,905	$212	0	$ 0	$3,105,238	$(2,245,862)	$ 859,588
Issuance of common stock	1,831	2			23,083		23,085
Share-based compensation					23,192		23,192
Common stock dividends						(29,760)	(29,760)
Net income						671,926	671,926
Treasury stock			(539)	(7,479)			(7,479)
Balance at December 31, 2010	213,736	$214	(539)	$(7,479)	$3,151,513	$(1,603,696)	$ 1,540,552

See accompanying notes.

EXCO Resources, Inc.

Notes to consolidated financial statements

1. Organization

Unless the context requires otherwise, references in this Annual Report on Form 10-K to "EXCO," "EXCO Resources," "Company," "we," "us," and "our" are to EXCO Resources, Inc., and its consolidated subsidiaries.

We are an independent oil and natural gas company engaged in the exploration, exploitation, development and production of onshore North American oil and natural gas properties. Our principal operations are conducted in key North American oil and natural gas areas including East Texas, North Louisiana, Appalachia and the Permian Basin in West Texas. In addition to our oil and natural gas producing operations, we own 50% interests in two midstream joint ventures located in East Texas/North Louisiana and Appalachia, respectively.

Our growth strategy is focused on the exploration, development and midstream infrastructure in two shale resource plays; the Haynesville/Bossier shale in East Texas/North Louisiana and the Marcellus shale in Appalachia. In order to accelerate the development efforts, we have entered into four separate joint ventures with affiliates of BG Group, plc, or BG Group. A brief description of each joint venture follows:

- East Texas/North Louisiana JV—On August 14, 2009, we entered into a joint venture with BG Group covering an undivided 50% interest in a substantial portion of our assets in the Haynesville/Bossier shale, or the East Texas/North Louisiana JV. The East Texas/North Louisiana JV is governed by a joint development agreement. Our subsidiary, EXCO Operating serves as operator of the East Texas/North Louisiana JV. We report the operating results and financial position of the East Texas/North Louisiana JV using proportional consolidation.
- TGGT—On August 14, 2009, we closed the sale to BG Group of a 50% interest in a newly formed company, TGGT Holdings, LLC, or TGGT, which now holds most of our East Texas/North Louisiana midstream assets. As a result of TGGT, we no longer report our midstream operations as a separate business segment. Effective August 14, 2009, we account for the jointly-held midstream operations as an equity method investment. The net operations of our gathering system in Louisiana that supports our Vernon Field operations, which was previously reported within our midstream segment and was not included in the formation of TGGT, is now reported in "Gathering and transportation" on the Consolidated Statement of Operations.
- Appalachia JV—On June 1, 2010, we entered into a joint venture with BG Group in the Appalachia region, or the Appalachia JV. EXCO and BG Group jointly operate the Appalachia JV operations through a 50/50 owned operating entity, or OPCO, which holds a 0.5% working interest in all of the shallow conventional assets and the deep rights in the Appalachia JV. Pursuant to the Appalachia JV, we sold 50% of our remaining 99.5% interest in the assets, or 49.75%, to BG Group. We use the equity method to account for our interest in OPCO and proportionally consolidate our 49.75% non-operating interest in the Appalachia area.
- Appalachia Midstream JV—On June 1, 2010, we also formed a jointly-owned midstream company, or the Appalachia Midstream JV, to provide take-away capacity in the Marcellus shale. We use the equity method to account for our investment in the Appalachia Midstream JV.

We expect to continue to grow by leveraging our management and technical team's experience, developing our shale resource plays, and exploiting our multi-year inventory of development drilling locations. We also continue to pursue acquisitions in the core areas of our shale plays. We employ the use of debt along with a comprehensive derivative financial instrument program to support our strategy. These approaches enhance our ability to execute our business plan over the entire commodity price cycle, protect our returns on investments and manage our capital structure.

The accompanying consolidated balance sheets as of December 31, 2010 and 2009, consolidated statements of operations, consolidated cash flows and consolidated changes in shareholders' equity for the years ended

December 31, 2010, 2009 and 2008 are for EXCO and its subsidiaries. The consolidated financial statements and related footnotes are presented in accordance with generally accepted accounting principles, or GAAP.

Beginning December 31, 2009, we reclassified certain items that relate to our operations from "Other income" into "Other operating items." Prior year amounts have been reclassified to conform to the current year presentation.

2. Summary of significant accounting policies

Principles of consolidation

We consolidate all of our subsidiaries in the accompanying consolidated balance sheets as of December 31, 2010 and 2009 and the consolidated statements of operations and consolidated statements of cash flows and changes in shareholders' equity for the years ended December 31, 2010, 2009 and 2008. Investments in unconsolidated affiliates in which we are able to exercise significant influence are accounted for using the equity method. All intercompany transactions and accounts have been eliminated.

Management estimates

In preparing financial statements in conformity with GAAP, we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses during the reporting periods. The more significant estimates pertain to proved oil and natural gas reserve volumes, future development costs, dismantlement and abandonment costs, share-based compensation expenses, estimates relating to oil and natural gas revenues and expenses, the fair market value of assets and liabilities acquired in business combinations, derivatives, goodwill 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.

Restricted cash

The restricted cash on our balance sheet is comprised principally of our share of an evergreen escrow account with BG Group which is used to fund our share of development operations in the East Texas/North Louisiana JV. Funds held in this escrow account are restricted solely to drilling and operations for the East Texas/North Louisiana JV.

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 financial institutions which we believe have sufficient credit quality to minimize risk of loss. We sell oil and natural gas to various customers. In addition, we participate with other parties in the drilling, completion and operation of oil and natural gas wells. The majority of our accounts receivable are due from either purchasers of oil or natural gas or participants in oil and natural gas wells for which we serve as the operator. We have the right to offset future revenues against unpaid charges related to wells which we operate. Oil and natural gas receivables are generally uncollateralized. The allowance for doubtful accounts receivable aggregated \$0.5 million and \$3.2 million at December 31, 2010 and 2009, respectively. We place our derivative financial instruments with financial institutions and other firms that we believe have high credit ratings. To mitigate our risk of loss due to default, we have entered into master netting agreements with our counterparties on our derivative financial instruments that allow us to offset our asset position with our liability position in the event of a default by the counterparty.

For the year ended December 31, 2010, sales to BG Energy Merchants LLC and Louis Dreyfus Energy Services LP accounted for approximately 21.5% and 10.1%, respectively, of total consolidated revenues.

BG Energy Merchants LLC is a subsidiary of BG Group. For the year ended December 31, 2009 there were no sales to any individual customer which exceeded 10% of our consolidated revenues. For the year ended December 31, 2008, sales to Crosstex Gulf Coast Marketing and Atmos Energy Marketing L.L.C. and its affiliates accounted for approximately 12.0% and 11.2%, respectively, of total consolidated revenues.

Derivative financial instruments

In connection with the incurrence of debt related to our exploration, exploitation, development, acquisition and producing activities, our management has adopted a policy of entering into oil and natural gas derivative financial instruments to mitigate the impacts of commodity price fluctuations and to achieve a more predictable cash flow. Financial Accounting Standards Board, or FASB, Accounting Standards Codification, or ASC, Topic 815 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 estimated fair value. ASC 815 requires that changes in the derivative's estimated fair value be recognized currently in earnings unless specific hedge accounting criteria are met, or exemptions for normal purchases and normal sales as permitted by ASC 815 exist. We do not designate our derivative financial instruments as hedging instruments and, as a result, recognize the change in a derivative's estimated fair value currently in earnings as a component of other income or expense.

Oil and natural gas properties

The accounting for, and disclosure of, oil and natural gas producing activities require that we choose between two GAAP alternatives; the full cost method or the successful efforts method. We use the full cost method of accounting, which involves capitalizing all exploration, exploitation, development and acquisition costs. Once we incur costs, they are recorded in the depletable pool of proved properties or in unproved properties, collectively, the full cost pool. Our unproved property costs, which include unproved oil and gas properties, properties under development, and major development projects, collectively totaled $599.4 million and $492.9 million as of December 31, 2010 and 2009, respectively, and are not subject to depletion. We review our unproved oil and natural gas property costs on a quarterly basis to assess for impairment and transfer unproved costs to proved properties as a result of extension or discoveries from drilling operations or determination that no Proved Reserves are attributable to such costs. We expect these costs to be evaluated in one to seven years and transferred to the depletable portion of the full cost pool during that time. The full cost pool is comprised of intangible drilling costs, lease and well equipment and exploration and development costs incurred plus acquired proved and unproved leaseholds.

When we acquire significant amounts of undeveloped acreage, we capitalize interest on the acquisition costs in accordance with FASB ASC Subtopic 835-20 for Capitalization of Interest. We began capitalizing interest in April 2008, upon identification and development of shale resource opportunities in the Haynesville and Marcellus areas. When the unproved property costs are moved to proved developed and undeveloped oil and natural gas properties, or the properties are sold, we cease capitalizing interest.

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

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 and/or the relationship between capitalized costs and Proved Reserves. The impacts on our depletion rate from the formation of the Appalachia JV in 2010 and the formation of the East Texas/North Louisiana JV in 2009, along with certain other divestiture transactions in 2009, as discussed in "Note 4. Divestitures and acquisitions," were considered significant and we recognized gains of $528.9 million, net of estimated post-closing adjustments which are subject to further changes, and $691.9 million in 2010 and 2009, respectively, on our divestitures.

Pursuant to Rule 4-10(c)(4) of Regulation S-X, at the end of each quarterly period, companies that use the full cost method of accounting for their oil and natural gas properties must compute a limitation on capitalized costs, or ceiling test. The ceiling test involves comparing the net book value of the full cost pool, after taxes, to the full cost ceiling limitation defined below. In the event the full cost ceiling is less than the full cost pool, we must record a ceiling test write-down of our oil and natural gas properties to the value of the full cost ceiling. The full cost ceiling limitation is computed as the sum of the present value of estimated future net revenues from our Proved Reserves by applying average prices as prescribed by the Securities and Exchange Commission, or SEC, Release No. 33-8995, less estimated future expenditures (based on current costs) to develop and produce the Proved Reserves, discounted at 10%, plus the cost of properties not being amortized and the lower of cost or estimated fair value of unproved properties included in the costs being amortized, net of income tax effects.

The ceiling test is computed using the simple average spot price for the trailing twelve month period using the first day of each month. For the twelve months ended December 31, 2010, the trailing twelve month reference price was $79.43 per Bbl for the West Texas Intermediate oil at Cushing, Oklahoma and $4.38 per Mmbtu for natural gas at Henry Hub. Each of the aforementioned reference prices for oil and natural gas are further adjusted for quality factors and regional differentials to derive estimated future net revenues. Under full cost accounting rules, any ceiling test write-downs of oil and natural gas properties may not be reversed in subsequent periods. Since we do not designate our derivative financial instruments as hedges, we are not allowed to use the impacts of the derivative financial instruments in our ceiling test computation. As a result, decreases in commodity prices which contribute to ceiling test write-downs may be offset by mark-to-market gains which are not reflected in our ceiling test results. There were no ceiling test write-downs during the year ended December 31, 2010.

The ceiling test calculation 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.

Write-down of oil and natural gas properties

For the year ended December 31, 2009, we recognized a ceiling test write-down in the first quarter of 2009 of $1.3 billion to our proved oil and natural gas properties. For the year ended December 31, 2008, we recognized ceiling test write-downs of $2.8 billion to our proved oil and natural gas properties. Under the full cost accounting rules in place prior to the SEC's Release No. 33-8995 on December 31, 2009, the SEC required the full cost ceiling to be computed using spot market prices for oil and natural gas at our balance sheet date.

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.

Inventory

Inventory includes tubular goods and other lease and well equipment which we plan to utilize in our ongoing exploration and development activities and is carried at the lower of cost or market. The inventory is capitalized to our full cost pool or gathering system assets once it has been placed into service.

Office, field and other equipment

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

Goodwill

In accordance with FASB ASC Subtopic 350-20 for Intangibles-Goodwill and Other, 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 as of December 31 of each year. Losses, if any, resulting from impairment tests will be reflected in operating income in the statement of operations.

The Appalachia JV and the East Texas/North Louisiana JV and other 2009 divestitures discussed in "Note 4. Divestitures and acquisitions" caused significant alterations to the depletion rate and the relationship between capitalized costs and Proved Reserves. As a result of their significance, we reduced goodwill by $51.4 million in 2010 and $177.6 million in 2009 when computing our gains on those transactions. In addition, TGGT, as discussed in "Note 4. Divestitures and acquisitions," resulted in a reduction of $11.4 million in goodwill against the associated gain and the transfer of $11.4 million of goodwill to the equity investment in TGGT.

The balance of goodwill as of December 31, 2010 and 2009 was $218.3 million and $269.7 million, respectively.

Deferred abandonment and asset retirement obligations

We apply FASB ASC Subtopic 410-20 for Asset Retirement and Environmental Obligations to account for estimated future plugging and abandonment costs. ASC 410-20 requires legal obligations associated with the retirement of long-lived assets to be recognized at their estimated fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost is capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset. Our asset retirement obligations primarily represents the present value of the estimated amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state laws.

The following is a reconciliation of our asset retirement obligations for the periods indicated:

	For the years ended December 31,		
(in thousands)	2010	2009	2008
Asset retirement obligations at beginning of period	$ 65,115	$120,671	$ 84,370
Activity during the period:			
Adjustment to liability due to acquisitions	11	389	15,128
Revisions in estimated assumptions	—	—	14,960
Liabilities incurred during period	1,936	879	4,222
Liabilities settled during period	(503)	(5,455)	(4,712)
Reduction to retirement obligations due to divestitures	(20,025)	(58,501)	—
Accretion of discount	3,758	7,132	6,703
Asset retirement obligations at end of period	50,292	65,115	120,671
Less current portion	900	900	1,830
Long-term portion	$ 49,392	$ 64,215	$118,841

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

Revenue recognition and gas imbalances

We use the sales method of accounting for oil and natural gas revenues. Under the sales method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers. A majority of our gas imbalances were concentrated in our Mid-Continent properties, which we sold during 2009, as discussed in "Note 4. Divestitures and acquisitions." Gas imbalances at December 31, 2010, 2009 and 2008 were not significant.

Gathering and transportation

We generally sell oil and natural gas under two types of agreements which are common in our industry. Both types of agreements include a transportation charge. One is a netback arrangement, under which we sell oil or natural gas at the wellhead and collect a price, net of the transportation incurred by the purchaser. In this case, we record sales at the price received from the purchaser, net of the transportation costs. Under the other arrangement, we sell oil or natural gas at a specific delivery point, pay transportation to a third party and receive proceeds from the purchaser with no transportation deduction. In this case, we record the transportation cost as gathering and transportation expense. Due to these two distinct selling arrangements, our computed realized prices, before the impact of derivative financial instruments, include revenues which are reported under two separate bases.

As a result of the formation of TGGT in 2009, the net operating results from our gathering system in North Louisiana that supports our Vernon Field operations, which was previously reported within our midstream segment, is now reported as a component of "Gathering and transportation" in the consolidated statements of operations.

Gathering and transportation expenses totaled $54.9 million, $19.0 million and $14.2 million for the years ended December 31, 2010, 2009 and 2008, respectively. The overall increase in gathering and transportation expenses is a result of new firm transportation agreements in the Haynesville area, which commenced in February 2010, along with fees charged by TGGT.

Capitalization of internal costs

We capitalize as part of our proved developed oil and natural gas properties a portion of salaries and related share-based compensation for employees who are directly involved in the acquisition and development of oil and natural gas properties. During the years ended December 31, 2010, 2009 and 2008, we capitalized $19.8 million, $18.3 million and $15.5 million, respectively. The capitalized amounts include $6.4 million, $5.1 million and $4.0 million of share-based compensation for the years ended December 31, 2010, 2009 and 2008, respectively.

Overhead reimbursement fees

We have classified fees from overhead charges billed to working interest owners, including ourselves, of $16.2 million, $24.6 million and $24.9 million, for the years ended December 31, 2010, 2009 and 2008, respectively, as a reduction of general and administrative expenses in the accompanying Consolidated Statements of Operations. Our share of these charges was $8.8 million, $16.6 million and $17.0 million for the years ended December 31, 2010, 2009 and 2008, respectively, and are classified as oil and natural gas production costs.

In addition, we have agreements with BG Group which allow us to bill them certain technical and overhead fees incurred on behalf of the East Texas/North Louisiana JV. For the years ended 2010 and 2009, we reduced general and administrative expenses by $23.5 million and $4.9 million, respectively, for these charges.

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 of accounting in accordance with FASB ASC Topic 740 Accounting for Income Taxes, 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 FASB ASC Subtopic 260-10 for Earnings Per Share. ASC 260-10 requires companies to present two calculations of earnings per share, or EPS; basic and diluted.

Basic earnings per common share is 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

We account for our stock-based compensation in accordance with FASB ASC Topic 718 for Compensation—Stock Compensation. ASC 718 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. We recognize expense on a straight-line basis over the vesting period of the option.

Our 2005 Long-Term Incentive Plan, as amended, or the 2005 Incentive Plan, provides for the granting of options and other equity incentive awards to purchase up to 23,000,000 shares of our common stock. New shares will be issued for any awards exercised. Since the adoption of the 2005 Incentive Plan, EXCO has issued only stock options, although the plan allows for other share-based awards.

3. Recent accounting pronouncements

On December 21, 2010, the FASB issued Accounting Standards Update, or ASU, No. 2010-29—Business Combinations (Topic 805): Disclosure of Supplementary Pro Forma Information for Business Combinations, or ASU 2010-29. ASU 2010-29 specifies that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. The update also expands the supplemental pro forma disclosures under Topic 805 to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The update is effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. This update was adopted by us on January 1, 2011 and will be considered if we enter into a business combination transaction.

On December 17, 2010, the FASB issued ASU No. 2010-28—Intangibles—Goodwill and Other (Topic 350): When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts, or ASU 2010-28. ASU 2010-28 modifies Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. For those reporting units, an entity is required to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. In determining whether it is more likely than not that a goodwill impairment exists, an entity should consider whether there are any adverse qualitative factors indicating that an impairment may exist. The update is effective for interim and annual reporting periods beginning after December 15, 2010. This update will be considered on an interim and annual basis when we review and perform our goodwill impairment test.

On January 21, 2010, the FASB issued ASU No. 2010-06—Fair Value Measurement and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements, or ASU 2010-06. ASU 2010-06 requires transfers, and the reasons for the transfers, between Levels 1 and 2 be disclosed. Fair value measurements using significant unobservable inputs should be presented on a gross basis and the fair value measurement disclosure should be reported for each class of asset and liability. Disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements will be required for fair value measurements that fall in either Level 2 or 3. The update is effective for interim and annual reporting periods beginning after December 15, 2009. See "Note 5. Derivative financial instruments and fair value measurements" for the impact to our disclosures.

4. Divestitures and acquisitions

2010 Divestitures and acquisitions

Appalachia JV

On June 1, 2010, we closed a transaction which resulted in the sale of a 50% undivided interest in substantially all of our Appalachian oil and natural gas proved and unproved properties and related assets to BG

Group for cash consideration of approximately $835.2 million. Subsequent to closing, we have accrued an estimated $45.0 million in post-closing adjustments, which will lower our cash proceeds to approximately $790.2 million. In addition to the cash consideration received at closing, BG Group agreed to fund 75% of our share of deep drilling and completion costs within our joint venture area until the carry amount is satisfied up to a total of $150.0 million. As of December 31, 2010, BG Group's remaining obligation was approximately $126.8 million, including a reduction of $10.6 million related to post-closing adjustments. In conjunction with the Appalachia JV, we entered into a Joint Development Agreement, or the Appalachia JDA, with BG Group. The effective date of the transaction was January 1, 2010.

EXCO and BG Group each own a 50% interest in an operating company, EXCO Resources (PA), LLC, or OPCO, which operates the properties located within the Appalachia JV, subject to oversight from a management board having equal representation from EXCO and BG Group. During 2010, we made $48.0 million in advances to OPCO to provide working capital for our share of properties. This advance was recorded as a prepaid asset and included in "Other" current assets on our consolidated balance sheets and will be offset by any payments made by OPCO for our interest in the properties. We will continue to fund OPCO with advances to develop the Appalachia properties. We use the equity method to account for our 50% interest in OPCO.

In addition to the upstream Appalachia properties, certain midstream assets were transferred to a newly formed, jointly owned entity, Appalachia Midstream, LLC, through which both EXCO and BG Group will pursue the construction and expansion of gathering systems, pipeline systems and treating facilities for anticipated future production from the Marcellus shale. We use the equity method to account for our 50% interest in Appalachia Midstream, LLC.

The sale of oil and natural gas properties in the Appalachia JV resulted in a significant alteration in our depletion rate. Accordingly, in accordance with full cost accounting rules, we recorded a gain, net of a proportionate net reduction in goodwill, of approximately $528.9 million during the year ended 2010. During the fourth quarter of 2010, we reduced the previously recognized gain by $45.0 million to reflect estimated post-closing adjustments in favor of BG Group. We expect the amount of the proceeds and gain to be finalized during 2011.

Common Transaction

On May 14, 2010, along with BG Group, we closed the joint purchase of Common Resources, L.L.C., or the Common Transaction, which owned properties in Shelby, San Augustine and Nacogdoches Counties, Texas in the Haynesville and Bossier shales. The purchase price was approximately $442.1 million ($221.0 million net to EXCO), after final purchase price adjustments. Our share of the acquisition price was financed with borrowings under our credit agreement, or the EXCO Resources Credit Agreement. The development of these assets is governed by the East Texas/North Louisiana JV.

Southwestern Transaction

On June 30, 2010, along with BG Group, we closed the joint purchase of undeveloped acreage and oil and natural gas properties in Shelby, San Augustine and Nacogdoches Counties, Texas in the Haynesville and Bossier shales from Southwestern Energy Company, or the Southwestern Transaction. The purchase price was $357.8 million ($178.9 million net to EXCO), after final purchase price adjustments. Our share of the acquisition price was financed with borrowings under the EXCO Resources Credit Agreement. The development of these assets is governed by the East Texas/North Louisiana JV. The majority of the assets acquired in the Southwestern Transaction represented incremental working interests in properties that EXCO and BG Group acquired in the Common Transaction.

The Common Transaction and the Southwestern Transactions were primarily acquisitions of unproved acreage prospective for Haynesville shale reserves, although both included interests in proved properties. The aggregate purchase prices to EXCO's interest of these two acquisition transactions of $399.9 million was allocated as follows: Unproved properties—$368.4 million; proved properties—$25.9 million; and working capital and other assets and liabilities—$5.6 million.

Chief Transaction

On December 21, 2010, we funded the acquisition of undeveloped acreage and oil and natural gas properties primarily in the Marcellus shale from Chief Oil & Gas LLC and related parties for approximately $459.4 million, subject to customary post-closing purchase price adjustments, or the Chief Transaction. The $459.4 million preliminary purchase price was funded into an escrow account pending receipt of a waiver from a third party. As a result, the $459.4 million is included in Deposits on acquisitions on our consolidated balance sheets as of December 31, 2010. As discussed in "Note 20. Subsequent events," the waiver was obtained on January 11, 2011 and all properties were released to us. The transaction had an effective date of July 1, 2010. BG Group participated in their 50% share of the Chief Transaction and funded $229.7 million on February 7, 2011.

We will record the Chief Transaction purchase price allocation in our 2011 financial statements. Based on the preliminary purchase price and taking into consideration BG Group's election to participate in their 50% share, our $229.7 million purchase price will be allocated as follows: Unproved properties—$209.2 million; proved properties—$20.6 million; other liabilities—$0.1 million.

Pending Appalachia Transaction

In December 2010, we entered into a definitive agreement with a private company for the purchase of additional Marcellus shale properties with associated shallow production primarily in Jefferson and Clarion counties in Pennsylvania for $95.0 million, which is expected to close in the first quarter of 2011. We have made a deposit equal to 5% of the purchase price, which is included in Deposits on acquisitions on our consolidated balance sheets as of December 31, 2010. The assets are located within the area of mutual interest, or the BG AMI, established by the Appalachia JV, which gives BG Group the right to purchase 50% of this acquisition.

2009 Divestitures and acquisitions

During 2009 we completed a $2.1 billion divesture program that allowed us to reduce our outstanding debt and exit our Mid-Continent division.

East Texas Transaction

On August 11, 2009, we closed a sale of properties located in East Texas, or the East Texas Transaction, with Encore Operating, LP, or Encore. Pursuant to the East Texas Transaction, we sold all of our interests in certain oil and natural gas properties located in our Overton Field and Gladewater area of East Texas. We received $154.3 million in cash, after final closing adjustments.

Mid-Continent Transaction

On August 11, 2009, we closed a sale of properties located in Texas and Oklahoma, or the Mid-Continent Transaction, with Encore. Pursuant to the Mid-Continent Transaction, we sold all of our interests in certain oil and natural gas properties located in our Mid-Continent operating area. We received $197.7 million in cash, after final closing adjustments.

East Texas/North Louisiana JV

On August 14, 2009, we closed a sale and joint development transaction with BG Group for the sale of an undivided 50% of our interest in the BG AMI which included most of our oil and natural gas assets in East Texas/North Louisiana (excluding the Vernon Field, Gladewater area, Overton Field and Redland Field). The East Texas/North Louisiana JV includes agreements for the joint development and operation of our Haynesville and Bossier shales and certain other related natural gas assets located in the BG AMI. We received $713.8 million in cash, after final closing adjustments and adjustments necessary to reflect the January 1, 2009 effective date. Pursuant to this transaction, BG Group also committed to fund $400.0 million of capital development attributable to our 50% interest, with BG Group paying 75% of our share of drilling and completion costs on the deep rights (Haynesville and Bossier shales) until the $400.0 million commitment is satisfied. Under the terms of the agreement, BG Group funding of the $400.0 million commitment will be satisfied solely through drilling of deep right wells as defined in the agreement. As of December 31, 2010, BG Group's remaining obligation was approximately $30.2 million.

TGGT

On August 14, 2009 we closed the sale to an affiliate of BG Group of a 50% interest in a newly formed company, TGGT Holdings, LLC, which now holds most of our East Texas/North Louisiana midstream assets, or the TGGT Transaction. Our Vernon Field midstream assets were excluded from the TGGT Transaction. Pursuant to a contribution agreement, we contributed TGG Pipeline, Ltd., or TGG, which owns an intrastate pipeline in East Texas and a gathering system in North Louisiana, and Talco Midstream Assets, Ltd., or Talco, which owns gathering assets in East Texas/North Louisiana, to TGGT. BG Group contributed $269.2 million in cash to TGGT and we received those funds from TGGT as a special distribution at closing. EXCO Operating now owns 50% of TGGT and an affiliate of BG Group owns 50% of TGGT. The effective date of this transaction was January 1, 2009. We adopted the equity method of accounting for our interest in TGGT upon its formation. The TGGT Transaction resulted in recognition of a gain of $98.3 million, net of an allocated reduction of goodwill previously ascribed to our midstream business segment.

The total cash proceeds of $983.0 million from the East Texas/North Louisiana JV and the TGGT Transaction were used to repay a $300.0 million senior unsecured term credit agreement, or the Term Credit Agreement, creation of an evergreen escrow funding account to develop the Haynesville operations, and a working capital contribution to TGGT, with the remainder applied to the outstanding balances under the EXCO Operating credit agreement.

The East Texas/North Louisiana JV, the TGGT Transaction and the Mid-Continent Transaction resulted in recognition of aggregate gains of $460.4 million, net of a proportionate reduction in goodwill, during the year ended December 31, 2009.

Sheridan Transaction

On November 10, 2009, we closed the sale of our remaining assets in our Mid-Continent operating area to Sheridan Holding Company I, LLC, or the Sheridan Transaction, for $531.2 million, after final closing adjustments. The sale was effective on October 1, 2009.

Proceeds from the Sheridan Transaction caused a significant alteration to our full cost pool and depletion rate. Accordingly, we recognized a gain, net of proportionate reduction in goodwill, on the Sheridan Transaction of $231.5 million.

EnerVest Transaction

On November 24, 2009, we closed the sale of our Ohio and certain Northwestern Pennsylvania producing assets to EV Energy Partners, L.P., or the EnerVest Transaction, along with certain institutional partnerships managed by EnerVest, Ltd., for $141.6 million, after final closing adjustments. The sale was effective on September 1, 2009. This transaction did not have a significant impact on our depletion rate and, therefore, all proceeds reduced our full cost pool.

Other transactions

During 2009, we also closed sales of certain non strategic assets, resulting in net cash proceeds of approximately $67.9 million after post-closing adjustments. These transactions did not significantly alter our full cost pool, therefore all proceeds reduced the full cost pool.

During the fourth quarter of 2009, we completed acquisitions totaling $251.5 million. While the acquisitions contained a minor amount of proved oil and natural gas properties, the strategic objective of the acquisitions was for the expansion of acreage in our shale resource plays. During 2010, BG Group elected to participate in 50% of these acquisitions pursuant to our joint development agreement.

2008 Acquisitions

During 2008, we completed acquisitions of proved and unproved oil and natural gas properties, undeveloped acreage and other assets. 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)	Appalachian Acquisition	New Waskom Acquisition	Danville Acquisition	Other acquisitions	Total acquisitions
Purchase price calculations:					
Purchase price	$386,703	$55,198	$249,451	$74,075	$765,427
Acquisition related expenses	741	—	178	—	919
Total purchase price	$387,444	$55,198	$249,629	$74,075	$766,346
Allocation of purchase price:					
Proved oil and natural gas properties	$334,308	$ —	$199,183	$71,232	$604,723
Unproved oil and natural gas properties	44,797	—	42,391	(18)	87,170
Other property and equipment	2,517	—	656	—	3,173
Gulf Coast sale		—	—	6,471	6,471
Gas gathering and related facilities	19,876	55,198	11,042	—	86,116
Asset retirement obligations	(12,647)	—	(1,029)	—	(13,676)
Other liabilities, net	(1,407)	—	(2,614)	(3,610)	(7,631)
Total purchase price allocation	$387,444	$55,198	$249,629	$74,075	$766,346

On February 20, 2008, we acquired shallow natural gas properties from EOG Resources, Inc. located primarily in EXCO's central Pennsylvania operating area, or the Appalachian Acquisition. The purchase price was $387.4 million and was financed with funds drawn under the EXCO Resources Credit Agreement.

On March 11, 2008, we acquired a gathering system in East Texas, or the New Waskom Acquisition, which contained 230 miles of pipeline and a gathering system at a cost of approximately $55.2 million. The New Waskom system is located primarily in Harrison and Panola Counties in East Texas and Caddo Parish in North Louisiana. The system has access to one plant and three interstate pipelines. The New Waskom Acquisition was funded with drawings under the EXCO Operating credit agreement.

On July 15, 2008, we acquired producing oil and natural gas properties, acreage and other assets in Gregg, Rusk and Upshur Counties of Texas, or the Danville Acquisition, for approximately $249.6 million, net of closing adjustments. Funding for this acquisition was provided by the Term Credit Agreement.

In addition to the acquisitions detailed above, we also acquired additional incremental interest in wells we own in our East Texas/North Louisiana areas, along with additional Proved Reserves in our Mid-Continent area.

5. Derivative financial instruments and fair value measurements

Our objective in entering into derivative financial instruments is to manage exposure to commodity price and interest rate 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 or increases in interest rates, but also limit the benefits we would realize if prices increase or interest rates decrease. When prices for oil and natural gas or interest rates are volatile, a significant portion of the effect of our derivative financial instrument management activities consists of non-cash income or expense 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.

We account for our derivative financial instruments in accordance with FASB ASC Topic 815 for Derivatives and Hedging, or ASC 815, which 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. ASC 815 also requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met, or exemptions for normal purchases and normal sales as permitted by ASC 815 exist. We do not designate our derivative financial instruments as hedging instruments for financial accounting purposes, and, as a result, we recognize the change in the respective instruments' fair value currently in earnings. In accordance with FASB ASC Section 815-10-65, the table below outlines the location of our derivative financial instruments on our consolidated balance sheets and their financial impact in our consolidated statement of operations.

Fair Value of Derivative Financial Instruments

(in thousands)	Balance Sheet location	December 31, 2010	December 31, 2009
Commodity contracts	Derivative financial instruments—Current assets	$73,176	$138,120
Commodity contracts	Derivative financial instruments—Long-term assets	23,722	34,677
Commodity contracts	Derivative financial instruments—Current liabilities	(3,775)	(1,246)
Commodity contracts	Derivative financial instruments—Long-term liabilities	(4,200)	(11,688)
Interest rate contracts	Derivative financial instruments—Current liabilities	—	(2,018)
Net derivative financial instruments		$88,923	$157,845

The Effect of Derivative Financial Instruments

		Years ended December 31,		
(in thousands)	Statements of Operations location	2010	2009	2008
Commodity contracts(1)	Gain on derivative financial instruments	$146,516	$232,025	$384,389
Interest rate contracts(2)	Interest expense	(45)	(4,319)	(9,290)
Net gain		$146,471	$227,706	$375,099

(1) Included in these amounts are net cash receipts of $217.4 million and $478.5 million for the year ended December 31, 2010 and 2009, respectively, and net cash payments of $109.3 million for the year ended December 31, 2008.

(2) Included in these amounts are net cash payments of $2.1 million and $12.2 million for the year ended December 31, 2010 and 2009, respectively, and net cash receipts of $0.6 million for the year ended December 31, 2008. Our interest rate swaps expired on February 14, 2010 and we have not entered into any new interest rate swap agreements as of December 31, 2010.

Settlements in the normal course of maturities of our derivative financial instrument contracts result in cash receipts from or cash disbursement to our derivative contract counterparties. Changes in the fair value of our derivative financial instrument contracts are included in income currently with a corresponding increase or decrease in the balance sheet fair value amounts. Unrealized fair value adjustments included in "Gain (loss) on derivative financial instruments" on the consolidated statements of operations, which do not impact cash flows, were losses of $70.9 million and $246.5 million for the years ended December 31, 2010 and 2009, respectively, and a gain of $493.7 million for the year ended December 31, 2008. Unrealized fair value adjustments included in "Interest expense" on the consolidated statements of operations, which do not impact cash flows, were gains of $2.0 million and $7.9 million for the years ended December 31, 2010 and 2009, respectively, and a loss of $9.9 million for the year ended December 31, 2008.

We place our derivative financial instruments with financial institutions and other firms that we believe have high credit ratings. To mitigate our risk of loss due to default, we have entered into master netting agreements with our counterparties on our derivative financial instruments that allow us to offset our asset position with our liability position in the event of a default by the counterparty.

Fair value measurements

We value our derivatives according to FASB ASC Topic 820 for Fair Value Measurements and Disclosures, which defines fair value as the exchange price that would be received for an asset or paid to transfer a liability (exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. This fair value may be different from the settlement value based on company-specific inputs, such as credit rating, futures markets and forward curves, and readily available buyers or sellers for such assets or liabilities.

We prioritize the inputs used in measuring fair value into a three-tier fair value hierarchy. These tiers include:

Level 1—Observable inputs, such as quoted market prices in active markets, for substantially identical assets and liabilities.

Level 2—Observable inputs other than quoted prices within *Level 1* for similar assets and liabilities. These include quoted prices in markets that are not active or other inputs that are observable or can be corroborated by observable market data. If the asset or liability has a specified or contractual term, the input must be observable for substantially the full term of the asset or liability.

Level 3—Unobservable inputs that are supported by little or no market activity, generally requiring development of fair value assumptions by management.

The following presents a summary of the estimated fair value of our derivative financial instruments for the years ended December 31, 2010 and 2009:

	For the year ended December 31, 2010			
(in thousands)	**Level 1**	**Level 2**	**Level 3**	**Total**
Oil and natural gas derivative financial instruments	$—	$ 88,923	$—	$ 88,923

	For the year ended December 31, 2009			
(in thousands)	**Level 1**	**Level 2**	**Level 3**	**Total**
Oil and natural gas derivative financial instruments	$—	$159,863	$—	$159,863
Interest rate swaps	—	(2,018)	—	(2,018)
	$—	$157,845	$—	$157,845

We evaluate derivative assets and liabilities in accordance with master netting agreements with the derivative counterparties, but report them gross on the consolidated balance sheets. Net derivative asset values are determined primarily by quoted futures prices and utilization of the counterparties' credit-adjusted risk-free rate curves and net derivative liabilities are determined by utilization of our credit-adjusted risk-free rate curve. The credit-adjusted risk-free rates of our counterparties are based on an independent market-quoted credit default swap rate curve for the counterparties' debt plus the London Interbank Offered Rate, or LIBOR, curve as of the end of the reporting period. Our credit-adjusted risk-free rate is based on the blended rate of independent market-quoted credit default swap rate curves for companies that have the same credit rating as us plus the LIBOR curve as of the end of the reporting period.

Oil and natural gas derivatives

Our commodity price derivatives represent oil and natural gas swaps. We have classified our oil and natural gas swaps and their related fair value tier as Level 2. During 2010, there were no changes in the fair value level classifications.

Oil derivatives. Our oil derivatives are swap contracts for notional Bbls of oil at fixed NYMEX West Texas Intermediate (WTI) oil prices. The asset and liability values attributable to our oil derivatives as of the end of the reporting period are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for WTI oil, (iii) the applicable estimated credit-adjusted risk-free rate curve, as described above.

Natural gas derivatives. Our natural gas derivatives are swap contracts for notional Mmbtus of gas at posted price indexes, including NYMEX Henry Hub (HH) swap contracts. The asset and liability values attributable to our natural gas derivatives as of the end of the reporting period are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for HH for natural gas swaps and PEPL index quotes for our existing basis swaps and (iii) the applicable credit-adjusted risk-free rate curve, as described above.

The following table presents our financial assets and liabilities for oil and natural gas derivative financial instruments measured at fair value as of December 31, 2010:

(in thousands, except prices)	Volume Mmbtus/Bbls	Weighted average strike price per Mmbtu/Bbl	Fair value at December 31, 2010
Natural gas:			
Swaps:			
2011	56,575	$ 5.62	$59,836
2012	27,450	5.65	15,521
2013	5,475	5.99	3,505
Total natural gas	89,500		78,862
Oil:			
Swaps:			
2011	547	111.32	9,565
2012	275	95.70	496
Total oil	822		10,061
Total oil and natural gas and derivatives			$88,923

At December 31, 2009, we had outstanding derivative contracts to mitigate price volatility covering 88,213 Mmcf of natural gas and 995 Mbbls of oil. At December 31, 2010, the average forward NYMEX natural gas price per Mmbtu for calendar 2011 and 2012 was $4.56 and $5.05, respectively, and the average forward NYMEX oil prices per Bbl for calendar 2011 and 2012 was $93.39 and $91.25, respectively.

Our derivative financial instruments covered approximately 53.1% and 83.0% of our total equivalent Mcfe production for the years ended December 31, 2010 and December 31, 2009, respectively.

Interest rate swaps

In January 2008, we entered into interest rate swaps to mitigate our exposure to fluctuations in interest rates on $700.0 million in principal of our credit agreement through February 14, 2010 at LIBOR ranging from 2.45% to 2.8%. The net derivative liability value attributable to our interest rate derivative contracts as of the end of the reporting period are based on (i) the contracted notional amounts, (ii) forward active market-quoted LIBOR yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. We have classified our interest rate swaps and their related fair value tier as Level 2.

Our interest rate swaps expired on February 14, 2010 and we have not entered into any new interest rate swap agreements as of December 31, 2010. During the twelve months ended December 31, 2010, our interest rate swaps had a net $0.1 million impact to interest expense. During the twelve months ended December 31, 2009, we recognized increases $4.3 million in interest expense related to our interest rate swaps. As of December 31, 2009, the fair value of our interest rate swaps was a liability of $2.0 million.

Fair value of other financial instruments

Our financial instruments include cash and cash equivalents, accounts receivable and payable and accrued liabilities. The carrying amount of these instruments approximates fair value because of their short-term nature. The carrying value of the EXCO Resources Credit Agreement approximates fair value.

The estimated fair value of our $750.0 million 7.5% senior unsecured notes maturing on September 15, 2018, or 2018 Notes, is $736.1 million with a carrying amount of $739.3 million as of December 31, 2010. The estimated fair value of our former 7 ¼% senior notes due January 15, 2011, or 2011 Notes, was $445.8 million with a carrying amount of $448.7 million as of December 31, 2009. The estimated fair value has been calculated based on market quotes.

6. Long-term debt

(in thousands)	December 31, 2010	December 31, 2009
EXCO Resources Credit Agreement	$ 849,000	$ 81,486
EXCO Operating credit agreement(1)	—	666,078
2018 Notes(2)	750,000	—
Unamortized discount on 2018 Notes	(10,731)	—
2011 Notes(2)	—	444,720
Unamortized premium on 2011 Notes	—	3,993
Total debt	$1,588,269	$1,196,277

(1) On April 30, 2010, the EXCO Operating credit agreement was consolidated into the EXCO Resources Credit Agreement.

(2) On September 15, 2010, we issued the 2018 Notes and used a portion of the proceeds to redeem the 2011 Notes.

As of December 31, 2010, we had total debt outstanding of approximately $1.6 billion consisting of borrowings under our EXCO Resources Credit Agreement of $849.0 million and $750.0 million of 2018 Notes. Terms and conditions of each of the debt obligations are discussed below.

EXCO Resources Credit Agreement

As of December 31, 2010, the EXCO Resources Credit Agreement, as amended, had a borrowing base of $1.0 billion, with $849.0 million of outstanding indebtedness and $135.5 million of available borrowing capacity. The borrowing base is redetermined semi-annually, with us and the lenders having the right to request interim unscheduled redeterminations in certain circumstances. Scheduled redeterminations are made on or about April 1 and October 1 of each year. The majority of our subsidiaries are guarantors under the EXCO Resources Credit Agreement, except those subsidiaries which are jointly held with BG Group and one other subsidiary that is wholly owned by us. The EXCO Resources Credit Agreement, as amended, permits investments, loans and advances to the unrestricted subsidiaries that are jointly held with BG Group, with certain limitations, along with allowing us to repurchase up to $200.0 million of our common stock. The EXCO Resources Credit Agreement matures on April 30, 2014.

Borrowings under the EXCO Resources Credit Agreement are collateralized by first lien mortgages providing a security interest of not less than 80% of the Engineered Value, as defined in the EXCO Resources Credit Agreement, in our oil and natural gas properties evaluated by the lenders for purposes of establishing our borrowing base. We are permitted to have derivative financial instruments covering no more than 100% of "forecasted production from total Proved Reserves" (as defined in the agreement) during the first two years of the forthcoming five year period, 90% of the forecasted production from total Proved Reserves for any month during the third year of the forthcoming five year period and 85% of the forecasted production from total Proved Reserves during the fourth and fifth year of the forthcoming five year period.

The EXCO Resources Credit Agreement, as amended, sets forth the terms and conditions under which we are permitted to pay a cash dividend on our common stock and provides that we may declare and pay cash dividends on our common stock in an amount not to exceed $50.0 million in any four consecutive fiscal quarters, provided that as of each payment date and after giving effect to the dividend payment date, (i) no default has occurred and is continuing, (ii) we have at least 10% of its borrowing base available under the EXCO Resources Credit Agreement, and (iii) payment of such dividend is permitted under our senior notes indenture.

The interest rate ranges from LIBOR plus 200 basis points, or bps, to LIBOR plus 300 bps depending upon borrowing base usage. The facility also includes an Alternate Base Rate, or ABR, pricing alternative ranging from ABR plus 100 bps to ABR plus 200 bps depending upon borrowing base usage.

As of December 31, 2010, we were in compliance with the financial covenants contained in the EXCO Resources Credit Agreement, which require that we:

- maintain a consolidated current ratio (as defined in the agreement) of at least 1.0 to 1.0 as of the end of any fiscal quarter; and
- not permit our ratio of consolidated funded indebtedness (as defined in the agreement) to consolidated EBITDAX (as defined in the agreement) to be greater than 3.50 to 1.0 at the end of any fiscal quarter ending on or after March 31, 2010.

The foregoing descriptions are not complete and are qualified in their entirety by the EXCO Resources Credit Agreement.

EXCO Operating credit agreement

On April 30, 2010, the EXCO Operating credit agreement was consolidated into the EXCO Resources Credit Agreement. Terms of the amended and restated agreement include, among other things, EXCO Operating and certain of its subsidiaries becoming guarantor subsidiaries under the EXCO Resources Credit Agreement.

Term Credit Agreement.

On December 8, 2008, EXCO Operating entered into the Term Credit Agreement with an aggregate balance of $300.0 million. Net proceeds from the loan of $274.4 million, after bank fees and expenses, were used to repay and terminate an original $300.0 million senior unsecured term credit agreement that was scheduled to mature on December 15, 2008. In addition to the fees incurred upon the closing of the Term Credit Agreement, EXCO Operating provided for additional fees on unpaid principal amounts, or duration fees, as defined in the agreement. These included a 5% fee on the unpaid principal on June 15, 2009 and an additional 3% fee on any unpaid outstanding balance as of September 15, 2009. On June 15, 2009 we remitted the first duration fee payment of $15.0 million.

In connection with the closings of the East Texas/North Louisiana JV, East Texas/North Louisiana Midstream Transaction and the East Texas Transaction, EXCO Operating repaid the outstanding $300.0 million under the Term Credit Agreement. As a consequence of the early payment of the Term Credit Agreement, EXCO Operating avoided payment of a $9.0 million duration fee that would have been due on September 15, 2009.

The unamortized balance of deferred financing costs attributable to the Term Credit Agreement of approximately $9.9 million was written off and is included in interest expense in the year ended December 31, 2009.

2011 Notes

On September 15, 2010 we provided notice to the trustee of our 2011 Notes, in accordance with the indenture, to fully redeem all of the $444.7 million outstanding notes. We used a portion of the proceeds from the issuance of the 2018 Notes to redeem the 2011 Notes, including accrued interest of $8.1 million from July 15, 2010 to the redemption date of October 15, 2010. As of December 31, 2009, $444.7 million in principal was outstanding on the 2011 Notes, with an unamortized premium of $4.0 million.

2018 Notes

On September 15, 2010 we closed on an underwritten offering of our $750.0 million 7.5% senior unsecured notes maturing on September 15, 2018. We received proceeds of approximately $724.1 million from the offering after deducting discounts to the underwriters and estimated offering fees and expenses. The balance of the net proceeds from the offering were used to redeem the 2011 Notes and reduce the balance under the EXCO Resources Credit Agreement. The bonds are guaranteed on a senior unsecured basis by EXCO's consolidated subsidiaries, other than EXCO Water Resources, LLC and all of our jointly-held equity investments with BG Group. Our equity investments with BG Group, other than OPCO, have been designated as unrestricted subsidiaries under the indenture governing the 2018 Notes.

As of December 31, 2010, $750.0 million in principal was outstanding on our 2018 Notes. The unamortized discount on the 2018 Notes at December 31, 2010 was $10.7 million. The estimated fair value of the 2018 Notes, based on quoted market prices, was $736.1 million on December 31, 2010.

Interest is payable on the 2018 Notes semi-annually in arrears on March 15 and September 15 of each year, beginning on March 15, 2011.

The Indenture governing the 2018 Notes contains covenants, which may limit our ability and the ability of our restricted subsidiaries to:

- incur or guarantee additional debt and issue certain types of preferred stock;
- pay dividends on our capital stock (over $50.0 million per annum) or redeem, repurchase or retire our capital stock or subordinated debt;
- make certain 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.

7. Preferred stock

On March 30, 2007, we issued Series A-1, Series B and Series C 7.0% Cumulative Convertible Perpetual Preferred Stock, or the 7.0% Preferred Stock and Series A-1 Hybrid Preferred Stock, or the Hybrid Preferred Stock, and together with the 7.0% Preferred Stock, the Preferred Stock, in several series at a purchase price of $10,000 per share. On July 18, 2008, we converted all outstanding shares of our Preferred Stock into a total of approximately 105.2 million shares of our common stock. The conversion of the Preferred Stock had the effect of increasing the book value of shareholders' equity by approximately $2.0 billion. We paid all accrued but unpaid dividends in cash totaling approximately $12.8 million to the holders of the converted shares of Preferred Stock as of July 18, 2008. After July 18, 2008, dividends ceased to accrue on the Preferred Stock and all rights of the holders with respect to the Preferred Stock terminated, except for the right to receive the whole shares of common stock issuable upon conversion, accrued dividends through July 18, 2008 and cash in lieu of any fractional shares.

We paid cash dividends totaling $82.8 million to the holders of our Preferred Stock from January 1, 2008 through July 18, 2008, the date upon which the preferred stock was converted into our common stock.

8. Environmental regulation

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

9. Commitments and contingencies

We lease our offices and certain equipment. Our rental expenses were approximately $8.2 million, $28.1 million and $21.3 million for the years ended December 31, 2010, 2009, and 2008, respectively. Our future minimum rental payments under operating leases with remaining noncancellable lease terms at December 31, 2010, are as follows:

(in thousands)	Firm Transportation	Other Fixed Commitments	Drilling Contracts	Operating Leases	Total
2011	$ 58,762	$115,315	$ 88,500	$ 7,251	$ 269,828
2012	89,201	95,218	37,755	6,632	228,806
2013	88,587	65,076	14,180	6,382	174,225
2014	88,587	20,211	28	6,020	114,846
2015	88,587	5,341	—	4,231	98,159
Thereafter	474,399	7,791	—	1,120	483,310
Total	$888,123	$308,952	$140,463	$31,636	$1,369,174

We have entered into firm transportation agreements with independent pipeline companies which commit us to ship approximately 870 Bcf per day for a period of ten years in the East Texas/North Louisiana area.

In the ordinary course of business, we are periodically a party to lawsuits. From time to time, natural gas producers, including EXCO, have been named in various lawsuits alleging underpayment of royalties in connection with natural gas and NGLs produced and sold. We have assessed, and recorded, our estimated exposure and do not currently believe that resolution of these matters will have a material impact to our current, or future, financial position or results of operations.

We do not believe that any resulting liability from any additional existing legal proceedings, individually or in the aggregate, will have a material adverse effect on our results of operations or financial condition and have properly reflected any potential exposure in our financial position when determined to be both probable and can be reasonably estimated.

In 2010, we have estimated net proceeds and gain on sale of assets associated with the Appalachia JV to be $790.2 million and $528.9 million, respectively, based on estimated post-closing adjustments and other contractual adjustments. As of December 31, 2010, the assumptions used for our estimated post-closing adjustments are subject to numerous factors, including acceptance by BG Group. We do not expect these final closing adjustments will be material to us.

10. Employee benefit plans

At December 31, 2010, we sponsored a 401(k) plan for our employees and matched 100% of employee contributions. Our matching contributions were $7.8 million, $7.0 million and $6.1 million for the years ended December 31, 2010, 2009 and 2008, respectively. Prior to 2008, we sponsored two 401(k) plans with different matching terms. Our separate plans were combined effective January 1, 2008.

11. Earnings per share

We account for earnings per share in accordance with FASB ASC Subtopic 260-10 for Earnings Per Share. ASC 260-10 requires companies to present two calculations of earnings per share; basic and diluted. Basic earnings (loss) per share for the years ended December 31, 2010, 2009 and 2008 equals the net income (loss) available to common shareholders divided by the weighted average common shares outstanding during the period. Common shares resulting from the conversion of our Preferred Stock on July 18, 2008 are included in the weighted average common shares for all periods presented. Diluted earnings (loss) per common share for the year ended December 31, 2010, 2009 and 2008 is computed in the same manner as basic earnings per share after assuming issuance of common stock for all potentially dilutive common stock equivalents, including our then outstanding Preferred Stock for the year ended 2008, whether exercisable or not. We excluded 4,099,255 antidilutive common stock equivalents from the year ended December 31, 2010 computation of diluted earnings per share. Since we incurred net losses for the years ended 2009 and 2008, we excluded 14,729,424 and 12,578,968, respectively, potential common stock equivalents from the diluted earnings per share calculation. We have also excluded 57,097,494 shares of common stock equivalents from the assumed conversion of the Preferred Stock from the computation of earnings per share for the year ended December 31, 2008, as they were antidilutive.

The following table presents basic and diluted earnings (loss) per share for the years ended December 31, 2010, 2009 and 2008 (in thousands, except per share amounts):

(in thousands, except per share amount)	Years ended December 31, 2010	2009	2008
Basic income (loss) per common share:			
Net income (loss)	$671,926	$(496,804)	$(1,810,468)
Shares:			
Weighted average number of common shares outstanding	212,465	211,266	153,346
Basic income (loss) per common share:			
Net income (loss) per common share	$ 3.16	$ (2.35)	$ (11.81)
Diluted income (loss) per share:			
Net income (loss)	$671,926	$(496,804)	$(1,810,468)
Shares:			
Weighted average number of common shares outstanding	212,465	211,266	153,346
Dilutive effect of stock options	3,270	—	—
Weighted average number of common shares and common stock equivalent shares outstanding	215,735	211,266	153,346
Diluted income (loss) per share:			
Net income (loss) per common share	$ 3.11	$ (2.35)	$ (11.81)

12. Stock options

We account for stock options in accordance with FASB ASC Topic 718 for Compensation—Stock Compensation. As required by ASC 718, the granting of options to our employees under our 2005 Incentive Plan are share-based payment transactions and are treated as compensation expense by us with a corresponding increase to additional paid-in capital.

The 2005 Incentive Plan, as amended, provides for the granting of options to purchase up to 23,000,000 shares of EXCO's common stock. The options expire ten years following the date of grant and have a weighted average remaining life of 7.0 years. Pursuant to the 2005 Incentive Plan, 25% of the options vest immediately with an additional 25% to vest on each of the next three anniversaries of the date of the grant. We have historically granted incentive stock options.

As of December 31, 2010 and 2009, there were 2,068,375 and 3,920,100 shares available to be granted under the 2005 Incentive Plan, respectively.

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

	Stock options	Weighted average exercise price per share	Weighted average remaining terms (in years)	Aggregate intrinsic value
Options outstanding at December 31, 2007	12,402,773	$12.06		
Granted	4,079,000	13.21		
Forfeitures	399,075	15.57		
Exercised	1,119,383	13.20		
Options outstanding at December 31, 2008	14,963,315	12.20		
Granted	3,072,650	17.05		
Forfeitures	650,300	15.32		
Exercised	931,371	11.12		
Options outstanding at December 31, 2009	16,454,294	13.04		
Granted	2,292,900	18.31		
Forfeitures	441,175	18.65		
Exercised	1,827,093	12.60		
Options outstanding at December 31, 2010	16,478,926	13.68	7.03	$99,054,486
Options exercisable at December 31, 2010	12,620,007	$12.73	6.41	$87,790,548

The weighted average grant date fair value of stock options granted during the years 2010, 2009 and 2008 were $10.19, $9.67 and $6.02, respectively. The total intrinsic value of stock options exercised for the years ended December 31, 2010, 2009 and 2008 was $11.3 million, $5.3 million and $11.4 million, respectively.

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 table below:

	2010	2009	2008
Expected life	7.5 years	7.5–8.5 years	5–8.5 years
Risk-free rate of return	2.04–3.52%	2.33–3.57%	1.71–3.33%
Volatility	54.37–56.80%	53.87–55.61%	34.17–55.26%
Dividend yield	0.45–1.15%	0.568–0.652%	0%

In connection with certain divestitures, we accelerated the vesting of a number of employee stock options on the date of the employee's termination and extended their exercise terms to one year from date of termination. For the year ended December 31, 2010, we recognized $0.9 million of additional compensation expense related to the modification of option terms which would have been recognized over the remaining life of the options had they not been accelerated. The underlying stock price on the dates of modification ranged from $14.70 to $21.23 and the exercise prices of the options accelerated ranged from $7.50 to $24.66.

Expected life was determined based on EXCO's exercise history, as well as comparable public companies. Risk-free rate of return is a rate of a similar term U.S. Treasury zero coupon bond. Volatility was determined based on the weighted average of historical volatility of our common stock and the daily closing prices from comparable public companies.

The following is a reconciliation of our stock option expense for the years ended December 31, 2010, 2009 and 2008:

(in thousands)	Years ended December 31, 2010	2009	2008
General and administrative expense	$15,800	$16,156	$11,804
Lease operating expense	1,041	2,831	4,174
Total share-based compensation expense	16,841	18,987	15,978
Share-based compensation capitalized	6,351	5,066	4,060
Total share-based compensation	$23,192	$24,053	$20,038

The total tax benefit for the years ended December 31, 2010, 2009 and 2008 was $1.3 million, $1.1 million and $1.7 million, respectively. Total share-based compensation to be recognized on unvested awards is $28.5 million over a weighted average period of 1.98 years as of December 31, 2010.

13. Income taxes

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

(in thousands)	Years ended December 31, 2010	2009	2008
Current:			
U.S.			
Federal	$ 1,348	$ —	$ —
State	260	(130)	252
Total current income tax (benefit)	1,608	(130)	252
Deferred:			
U.S.			
Federal	248,132	(130,740)	(693,391)
State	29,050	(20,606)	(88,266)
Valuation allowance	(277,182)	141,975	526,372
Total deferred income tax (benefit)	—	(9,371)	(255,285)
Total income tax (benefit)	$ 1,608	$ (9,501)	$(255,033)

We have net operating loss carryforwards, or NOLs, for United States income tax purposes that have either been generated from our operations or were purchased in our acquisitions. Our NOLs are scheduled to expire if not utilized between 2011 and 2029. 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 various dates between December 19, 1997 and October 3, 2005. In addition, we experienced a change in control on August 30, 2007 based upon the transformation of the Hybrid Preferred Stock to the same terms as the 7.0% Preferred Stock, but the result was no limitation on 2007 NOLs. As of December 31, 2010, the $9.3 million of foreign tax credits expired and we utilized all of our pre-2007 Section 382 limited NOLs. Our total NOL available for utilization at December 31, 2010 is approximately $751.7 million.

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, 2010	December 31, 2009
Current deferred tax assets (liabilities):		
Basis difference in fair value of derivative financial instruments	$ —	$ —
Other	6,330	—
Valuation allowance	(6,330)	—
Total current deferred tax assets (liabilities)	—	—
Non-current deferred tax assets:		
Net operating loss and AMT credits carryforwards—U.S.	297,661	316,867
Basis difference in fair value of derivative financial instruments	—	—
Purchase accounting adjustment to bond premium	—	3,206
Share-based compensation	7,391	6,592
Foreign tax credit carryforwards	—	9,336
Tax basis of oil and natural gas properties in excess of book basis	529,022	770,598
Tax basis of temporary goodwill in excess of book basis	14,756	11,783
Other	83	84
Total long-term deferred tax assets	848,913	1,118,466
Valuation allowance	(381,206)	(677,683)
Net total non-current deferred tax assets	467,707	440,783
Non-current deferred tax liabilities:		
Book basis of oil and natural gas properties in excess of tax basis	—	—
Book basis of gathering and other properties in excess of tax basis	(411,761)	(331,000)
Book basis of investment in partnership in excess of tax basis	(31,749)	(60,557)
Basis difference in fair value of derivative financial instruments	(24,197)	(49,226)
Basis of temporary goodwill	—	—
Total non-current deferred liabilities	(467,707)	(440,783)
Net total non-current deferred tax assets (liabilities)	$ —	$ —

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 years ended December 31, 2010, 2009 and 2008 is presented in the following table:

(in thousands)	Year ended December 31, 2010	2009	2008
United States federal income taxes (benefit) at statutory rate of 35%	$ 235,737	$(177,207)	$(695,977)
Increases (reductions) resulting from:			
Goodwill	11,556	43,455	—
Adjustments to the valuation allowance	(277,182)	141,975	526,372
Non-deductible compensation	2,098	2,808	2,321
State taxes net of federal benefit	29,050	(20,606)	(88,266)
Other	349	74	517
Total income tax provision	$ 1,608	$ (9,501)	$(255,033)

During 2010, our income tax rate was impacted by an increase in income that resulted in utilization of net operating losses that was further adjusted by the release of valuation allowances against deferred tax assets. The net result is a current alternative minimum tax and state income tax liability related to divestitures of properties.

During 2009, our income tax rate was impacted by the recognition of valuation allowances against deferred tax assets, which were primarily due to ceiling test write-downs that caused previous book basis and tax basis differences to change from deferred tax liabilities to deferred tax assets and divestitures of properties.

During 2008, our income tax rate was impacted by the establishment of a valuation allowances against deferred tax assets, which were primarily due to ceiling test write-downs that caused previous book basis and tax basis differences to change from deferred tax liabilities to deferred tax assets. Our deferred tax assets were offset by valuation allowances after testing to determine if the asset would meet a more likely than not criteria for realization pursuant to FASB ASC Topic 740- Income Taxes.

The Company adopted the provisions of FASB ASC Subtopic 740-10 for Income Taxes on January 1, 2007. As a result of the implementation of ASC Subtopic 740-10, the Company recognized zero liabilities for unrecognized tax benefits. As of December 31, 2010, 2009 and 2008, the Company's policy is to recognize interest related to unrecognized tax benefits of interest expense and penalties in operating expenses. The Company has not accrued any interest or penalties relating to unrecognized tax benefits in the current financials.

EXCO files income tax returns in the U.S. federal jurisdictions and various state jurisdictions. With few exceptions, EXCO is no longer subject to U.S. federal and state and local examinations by tax authorities for years before 2004. The Internal Revenue Service, or IRS, completed its examination of EXCO's 2004 U.S. federal income tax return in January 2008, which resulted in the creation of foreign tax credit carryforwards that expired in 2010.

14. Related party transactions

Corporate use of personal aircraft

We have periodically chartered, for company business, two 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 these aircraft. The Company believes that prudent use of a chartered private airplane by our senior management while on company business can promote efficient use of management time. Such usage can allow for unfettered, confidential communications among management during the course of the flight and minimize airport commuting and waiting time, thereby promoting maximum use of management time for company business. However, we restrict the use of the aircraft to priority company business being conducted by senior management in a manner that is cost effective for us and our shareholders. As a result, EXCO's reimbursed use of the aircraft is restricted to 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 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. 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 incurred by the pilots.

In 2009, the approved rate was $5,700 per flight hour plus $600 per flight hour fuel surcharge for the larger aircraft, and $3,000 per flight hour plus a $600 per flight hour surcharge for the smaller aircraft. In August 2009, the Audit Committee approved a rate of $5,400 per flight hour plus $400 per flight hour fuel surcharge for the large aircraft, and a rate of $3,700 per flight hour plus a $400 per flight hour surcharge for the smaller aircraft. In November 2010, the revised rate for the larger plane was reduced to $5,300 per flight hour plus $300 per flight hour fuel surcharge.

For the years ended December 31, 2010, 2009 and 2008, expenses incurred by EXCO payable directly to DHM Aviation, LLC or indirectly through an invoicing agent for use of these aircraft aggregated $1.1 million, $1.1 million and $0.8 million, respectively.

Other

Penny Wilson, the spouse of Mark E. Wilson, our Vice President, Chief Accounting Officer and Controller, was retained by us during 2010 as a consultant to support certain marketing and operational functions. During 2010, fees paid to Ms. Wilson totaled approximately $0.1 million.

Jeff Smith, the son of Stephen F. Smith, our Vice Chairman, President, Chief Financial Officer and one of our directors, owns a 50% interest in S&S Directional Drilling, LLC, or S&S. One of EXCO's vendors, Select Energy Services, LLC, or Select, and/or its affiliates subcontracts with S&S to provide equipment for use in connection with services provided by Select and/or its affiliates to EXCO. During 2010 and 2009, S&S was paid approximately $6.9 million and $0.8 million, respectively, by Select and/or its affiliates for the use of equipment in connection with services provided to EXCO.

15. Segment information

We follow FASB ASC Topic 280 for Segment Reporting when reporting operating segments. Prior to the August 19, 2009 East Texas/North Louisiana midstream joint venture where we sold a 50% interest in most of our East Texas/North Louisiana midstream operations, our reportable segments consisted of exploration and production and midstream. Our exploration and production segment and midstream segment were managed separately because of the nature of their products and services. The exploration and production segment is responsible for acquisition, development and production of oil and natural gas. The midstream segment was responsible for purchasing, gathering, transporting, processing and treating natural gas. We evaluated the performance of our operating segments based on segment profits, which included segment revenues, excluding the gain (loss) on derivative financial instruments, from external and internal customers and segment costs and expenses. Segment profit generally excluded income taxes, interest income, interest expense, unallocated corporate expenses, depreciation and depletion, asset retirement obligations, and gains and losses associated with ceiling test write-downs and asset sales, other income and expense, and income from equity investments.

As a result of the East Texas/North Louisiana midstream joint venture, we reviewed the criteria outlined in ASC 280-10 and determined that the midstream assets we retained, made up exclusively of the Vernon Field midstream assets, were not material and therefore, would no longer meet thresholds to be defined as a reportable segment. We also reviewed our equity investment in TGGT and concluded that it also would not be considered a reportable segment. We now account for our interest in TGGT using the equity method (see "Note 16. Equity investments").

The reportable midstream segment for 2009 is effective from January 1, 2009 through August 13, 2009. The Vernon Field midstream assets operations are included in the exploration and production segment effective August 14, 2009.

Summarized financial information concerning our reportable segments is shown in the following table:

(in thousands)	Exploration and production	Midstream	Intercompany eliminations	Consolidated total
For the year ended December 31, 2010				
Third party revenues	$ 515,226	$ —	$ —	$ 515,226
Intersegment revenues	—	—	—	—
Total revenues	$ 515,226	$ —	$ —	$ 515,226
Segment profit	$ 352,165	$ —	$ —	$ 352,165
For the year ended December 31, 2009:				
Third party revenues	$ 550,505	$ 35,330	$ —	$ 585,835
Intersegment revenues	(20,356)	41,148	(20,792)	—
Total revenues	$ 530,149	$ 76,478	$(20,792)	$ 585,835
Segment profit	$ 333,560	$ 20,106	$ —	$ 353,666
For the year ended December 31, 2008:				
Third party revenues	$1,404,826	$ 85,432	$ —	$1,490,258
Intersegment revenues	(32,296)	62,204	(29,908)	—
Total revenues	$1,372,530	$147,636	$(29,908)	$1,490,258
Segment profit	$1,120,253	$ 34,931	$ —	$1,155,184
As of December 31, 2010:				
Capital Expenditures	$ 561,794	$ —	$ —	$ 561,794
Goodwill	$ 218,256	$ —	$ —	$ 218,256
Total assets	$3,477,420	$ —	$ —	$3,477,420
As of December 31, 2009:				
Capital Expenditures	$ 458,410	$ 53,122	$ —	$ 511,532
Goodwill	$ 269,656	$ —	$ —	$ 269,656
Total assets	$2,358,894	$ —	$ —	$2,358,894

The following table reconciles the segment profits reported above to income (loss) before income taxes:

(in thousands)	Year ended December 31, 2010	2009	2008
Segment profits	$ 352,165	$ 353,666	$ 1,155,184
Depreciation, depletion and amortization	(196,963)	(221,438)	(460,314)
Write-down of oil and natural gas properties	—	(1,293,579)	(2,815,835)
Accretion of discount on asset retirement obligations	(3,758)	(7,132)	(6,703)
General and administrative	(105,114)	(99,177)	(87,568)
Gain on divestitures and other operating items	509,872	676,434	2,692
Interest expense	(45,533)	(147,161)	(161,638)
Gain on derivative financial instruments	146,516	232,025	384,389
Equity income (loss)	16,022	(69)	—
Other income (expense)	327	126	1,289
Income (loss) before income taxes	$ 673,534	$ (506,305)	$(1,988,504)

16. Equity investments

We hold equity investments in three entities with BG Group, which are described below. We use the equity method of accounting for each investment.

In conjunction with the Appalachia JV that closed on June 1, 2010, we own a 50% interest in OPCO, which operates the properties, subject to oversight from a management board having equal representation from EXCO and BG Group. Our investment in OPCO is equal to the working capital and historical costs of assets we transferred to OPCO, less the 50% interest we sold to BG Group upon closing the Appalachia JV. Our 50% equity interest in OPCO exceeds the book value of our investment in OPCO by $1.6 million, representing the difference in the historical basis of our investment and our 50% interest in OPCO, which reflects the fair value of BG Group's purchase for its 50% interest. The $1.6 million basis difference is being amortized over the estimated amortized life of OPCO's unproved properties.

The second equity method investee relates to certain midstream assets owned by EXCO in Appalachia that were transferred to a newly formed, jointly owned entity, Appalachia Midstream, LLC, through which EXCO and BG Group will pursue the construction and expansion of gathering systems for anticipated future production from the Marcellus shale. Our investment in Appalachia Midstream, LLC represents 50% of the net book value of Appalachia Midstream, LLC.

Our third equity method investment is our 50% ownership in TGGT, which hold interests in midstream assets in East Texas and North Louisiana. The following tables present summarized consolidated financial information of our equity investments and a reconciliation of our investment to our proportionate 50% interest.

(in thousands)	December 31, 2010	December 31, 2009
Assets		
Total current assets	$ 126,327	$ 54,818
Property and equipment, net	865,481	509,501
Other assets	8,675	—
Total assets	$1,000,483	$564,319
Liabilities and members' equity		
Total current liabilities	$ 145,643	$ 40,915
Total long-term liabilities	10,092	2,393
Members' equity:		
Total members' equity	844,748	521,011
Total liabilities and members' equity	$1,000,483	$564,319

	For the year ended December 31, 2010	For the period from August 14, 2009 to December 31, 2009
Revenues		
Oil and natural gas	$ 168	$ —
Midstream	160,039	37,904
Total revenues	160,207	37,904
Costs and expenses:		
Oil and natural gas production	268	—
Midstream operating	96,515	31,062
Other expenses	16,396	2,753
Depreciation, depletion and amortization	18,226	5,350
Total costs and expenses	131,405	39,165
Income before income taxes	28,802	(1,261)
Income tax expense	288	110
Net income (loss)	$ 28,514	$ (1,371)
EXCO's share of equity income (loss) before amortization	$ 14,257	$ (686)
Amortization of the difference in the historical basis of our contribution	1,765	617
EXCO's share of equity income (loss) after amortization	$ 16,022	$ (69)

(in thousands)	As of December 31, 2010	As of December 31, 2009
Equity investments	$379,001	$216,987
Basis adjustment(1)	45,755	44,135
Cumulative amortization of basis adjustment(2)	(2,382)	(617)
EXCO's 50% interest in December 31, 2010 equity investments	$422,374	$260,505

(1) Our equity in TGGT and OPCO, at inception, exceeded the book value of our investments by an aggregate of $45.8 million, comprised of an aggregate $57.2 million difference in the historical basis of our contribution and the fair value of BG Group's contribution offset by $11.4 million of goodwill included in our investment in TGGT. The $1.6 million increase from 2009 is a result of the formation of OPCO in 2010.

(2) The aggregate $57.2 million basis difference is being amortized over the estimated life of the associated assets.

17. Dividends

On November 18, 2010 our Board of Directors approved a fourth quarter 2010 cash dividend of $0.04 per share. The total cash dividend of $8.5 million was paid on December 15, 2010 to holders of record on November 30, 2010. Total dividends paid in 2010 to our shareholders were $29.8 million. Any future declaration of dividends, as well as the establishment of record and payment dates, is subject to limitations under the EXCO Resources Credit Agreement, our 2018 Notes and the approval of EXCO's Board of Directors.

18. Share repurchase

On July 19, 2010, we announced a share repurchase program which authorizes us to purchase up to $200.0 million of our common stock. Any repurchases will be made in the open market, in privately negotiated transactions or in structured share repurchase programs, and may be made from time to time and in one or more large repurchases. The program will be conducted in compliance with the Securities and Exchange Commission's Rule 10b-18 and applicable legal requirements and shall be subject to market conditions and other factors. EXCO is not obligated to repurchase any common stock, or any particular amount of common stock, and the repurchase program may be modified or suspended at any time at EXCO's discretion. The repurchases may be funded from available cash or borrowings under the EXCO Resources Credit Agreement.

As of December 31, 2010, we have repurchased a total of 539,221 shares for $7.5 million at an average price of $13.87 per share. We are not presently pursuing any repurchases pending strategic alternatives being evaluated by a special committee of our Board of Directors in connection with a proposal from our Chairman and Chief Executive Officer to purchase all of our outstanding common stock which he does not already own.

19. Acquisition proposal

On October 29, 2010, our Chairman and Chief Executive Officer, Douglas H. Miller presented a letter to our board of directors indicating an interest in acquiring all of the outstanding shares of our stock not already owned by Mr. Miller for a cash purchase price of $20.50 per share. The proposal does not represent a definitive offer and is there is no assurance that a definitive offer will be made or accepted, that any agreement will be executed or that any transaction will be consummated.

Our board of directors established a special committee on November 4, 2010 comprised of two independent directors to, among other things, evaluate and determine the Company's response to the October 29, 2010 proposal. The special committee retained Kirkland & Ellis LLP and Jones Day as its counsel and Barclays Capital, Inc. and Evercore Partners as its financial advisors to assist it in, among other things, evaluating and determining the Company's response to the proposal.

Between November 3, 2010 and February 1, 2011, nine related shareholder derivative lawsuits were filed purportedly on behalf of the Company in state and federal courts in Dallas, Texas alleging claims related to Mr. Miller's proposal. The lawsuits name as defendants all of the members of our board of directors, and in some of the lawsuits, also name as defendants two of our investors, Oaktree Capital Management, L.P. and Ares Management, LLC. The Company is named as a nominal defendant in each of the cases. The shareholder derivative lawsuits generally allege that our directors have breached their fiduciary duties by failing to implement fair and adequate procedures for the consideration of Mr. Miller's proposal and for failing to maximize shareholder value. The remaining defendants are alleged to have aided and abetted the purported breaches of fiduciary duty. The plaintiffs seek on behalf of the Company an injunction preventing consummation of Mr. Miller's proposed transaction, unspecified compensatory damages from the defendants other than the Company, and an award of attorney's fees and costs.

Also, since November 3, 2010, two putative shareholder class actions have been filed against the Company and all of the members of our board of directors in a state district court in Dallas County, Texas. The purported class action alleges that the Company and our directors breached fiduciary duties allegedly owed to public shareholders by attempting to consummate a transaction based on Mr. Miller's proposal. The plaintiff seeks unspecified damages, an order rescinding any transaction based on Mr. Miller's proposal, an accounting from the defendants for any profits or special benefits they may have received, and an award of attorney's fees and costs.

All of the state and county court proceedings have been consolidated into one court and lead plaintiffs counsel has been appointed for both the derivative actions and the direct class actions.

On January 12, 2011, in connection with the strategic review process, the Company and the special committee entered into an agreement with Mr. Miller containing customary confidentiality and standstill provisions. The standstill provisions prohibit Mr. Miller from, among other things, acquiring additional shares of EXCO common stock, entering into agreements regarding or soliciting proxies in connection with an acquisition of the Company and seeking to influence the management of the Company in connection with such an acquisition. In addition, the agreement prohibits Mr. Miller from entering into agreements preventing EXCO shareholders from voting in favor of or tendering their shares in other offers to acquire the Company or preventing financing sources from providing financing to other parties in connection with an acquisition of the Company. The agreement also limits the parties with whom Mr. Miller can enter into financing arrangements. The special committee expects to enter into similar agreements with other parties interested in exploring a possible acquisition of the Company.

In addition, at the direction of the special committee, on January 12, 2011, the Company adopted a shareholder rights plan, or the Rights Plan, with a one year term. The Rights Plan is intended to enhance the ability of the special committee to conduct a thorough, deliberative process of exploring our strategic alternatives. Under the terms of the rights plan, one right attached to each share of the Company's common stock that was outstanding as of the close of business on January 24, 2011 and one right will attach to each share issued thereafter prior to the expiration of the rights. The rights will become exercisable (subject to customary exceptions) only if a person or group acquires 10% or more of the Company's common stock (thereby becoming an "acquiring person") or commences a tender offer for 10% or more of the Company's common stock. The plan exempts each holder of 10% or more of the Company's common stock on the date of the plan's adoption as long as they do not thereafter acquire an additional 1% or more shares of the Company's common stock, as well as parties that enter into qualifying standstill agreements with the Company. The special committee may, in its sole discretion, also exempt any transaction from triggering the plan. The rights expire on January 24, 2012.

On January 13, 2011, the special committee of the board of directors announced that it will explore strategic alternatives to maximize shareholder value, including a potential sale of the Company. As part of a comprehensive process, the special committee stated that it will consider Mr. Miller's proposal as well as acquisition proposals the special committee may receive from other interested parties and other strategic alternatives potentially available to the Company. There can be no assurance that the special committee's exploration of strategic alternatives will result in a sale of the Company or any other transaction.

20. Subsequent events

In connection with the Chief Transaction, all necessary consents from third parties were received on January 11, 2011 and the escrow accounts holding the purchase price were released. BG Group subsequently elected to participate for their 50% share of the Chief Transaction and paid us $229.7 million on February 7, 2011, equal to one-half of our preliminary purchase price, subject to post-closing adjustments.

On January 31, 2011, the TGGT Credit Agreement was closed and we received a $125.0 million distribution from TGGT. The proceeds from this distribution were used to reduce outstanding debt under the EXCO Resources Credit Agreement.

21. Consolidating financial statements

Effective April 30, 2010, the EXCO Operating credit agreement was consolidated into the EXCO Resources Credit Agreement, with certain non-guarantor subsidiaries, including EXCO Operating, which owns all of our East Texas/North Louisiana assets, becoming restricted subsidiaries and guarantor subsidiaries under our 2011 Notes. The accompanying condensed consolidating financial statements are presented as if the previous non-guarantor subsidiaries were guarantor subsidiaries for each of the periods presented.

As of December 31, 2010, all of EXCO's subsidiaries are guarantors under the EXCO Resources Credit Agreement and the indenture governing the 2018 Notes with the exception of those equity investments that are jointly held with BG Group and one Subsidiary that is wholly owned by EXCO Operating Company. All of our non-guarantor subsidiaries are considered unrestricted subsidiaries under the 2018 Notes, with the exception of our equity investment in OPCO. As of December 31, 2010:

- Our equity method investment in OPCO was $0.3 million, consisting of $0.9 million of net assets transferred to the joint venture on June 1, 2010, a $0.3 million capital contribution and $0.9 of equity method losses.
- Our interests in jointly held entities with BG Group, with the exception of OPCO, represented $378.7 million of equity method investments, or 10.9% of our total assets and contributed $16.9 million of equity method income.
- Our non-guarantor, unrestricted subsidiaries that are wholly owned represented approximately 2.6% of our total revenues, 0.5% of our total assets and $6.7 million of liabilities, including trade payables, but excluding intercompany liabilities.

Set forth below are condensed consolidating financial statements of EXCO, the guarantor subsidiaries and the non-guarantor subsidiaries. The 2018 Notes, which were issued by EXCO Resources, Inc., are jointly and severally guaranteed by some of our subsidiaries (referred to as Guarantor Subsidiaries). Each of the Guarantor Subsidiaries are wholly-owned subsidiaries of Resources (defined below), and the guarantees are unconditional as it relates to the assets of the Guarantor Subsidiaries. For purposes of this footnote, EXCO Resources, Inc. is referred to as Resources to distinguish it from the Guarantor Subsidiaries.

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 Subsidiaries and the Non-Guarantor Subsidiaries is 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, 2010

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 76,763	$ (32,534)	$ —	$ —	$ 44,229
Restricted cash	—	161,717	—	—	161,717
Other current assets	83,913	230,590	11	—	314,514
Total current assets	160,676	359,773	11	—	520,460
Equity Investment	—	—	379,001	—	379,001
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties and development costs not being amortized	37,818	561,591	—	—	599,409
Proved developed and undeveloped oil and natural gas properties	385,357	1,985,605	—	—	2,370,962
Accumulated depletion	(295,453)	(1,016,763)	—	—	(1,312,216)
Oil and natural gas properties, net	127,722	1,530,433	—	—	1,658,155
Gas gathering, office and field equipment, net	28,837	131,276	16,193	—	176,306
Investments in and advances to affiliates	964,806	92,973	—	(1,057,779)	—
Deferred financing costs, net	30,704	—	—	—	30,704
Derivative financial instruments	13,665	10,057	—	—	23,722
Goodwill	38,100	180,156	—	—	218,256
Other assets	3	470,813	—	—	470,816
Total assets	$ 1,364,513	$ 2,775,481	$395,205	$(1,057,779)	$ 3,477,420
Liabilities and shareholders' equity					
Current liabilities	$ 50,654	$ 228,332	$ 6,712	$ —	285,698
Long-term debt, net of current maturities	1,588,269	—	—	—	1,588,269
Deferred income taxes	—	—	—	—	—
Other liabilities	10,234	52,667	—	—	62,901
Payable to parent	(1,825,196)	1,821,530	3,666	—	—
Total shareholders' equity	1,540,552	672,952	384,827	(1,057,779)	1,540,552
Total liabilities and shareholders' equity	$ 1,364,513	$ 2,775,481	$395,205	$(1,057,779)	$ 3,477,420

EXCO Resources, Inc.

Consolidating balance sheet

December 31, 2009

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 47,412	$ 20,995	$ —	$ —	$ 68,407
Restricted cash	—	58,909	—	—	58,909
Other current assets	69,449	204,880	443	—	274,772
Total current assets	116,861	284,784	443	—	402,088
Equity investment in TGGT Holdings, LLC	—	—	216,987	—	216,987
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties	54,570	391,883	46,429	—	492,882
Proved developed and undeveloped oil and natural gas properties	328,135	1,541,682	5,932	—	1,875,749
Accumulated depletion	(274,275)	(858,329)	—	—	(1,132,604)
Oil and natural gas properties, net	108,430	1,075,236	52,361	—	1,236,027
Gas gathering, office and field equipment, net	8,175	181,261	—	—	189,436
Investments in and advances to affiliates	198,661	—	—	(198,661)	—
Deferred financing costs, net	3,166	4,436	—	—	7,602
Derivative financial instruments	31,312	3,365	—	—	34,677
Goodwill	38,100	231,556	—	—	269,656
Other assets	3	2,418	—	—	2,421
Total assets	$ 504,708	$1,783,056	$269,791	$(198,661)	$ 2,358,894
Liabilities and shareholders' equity					
Current liabilities	$ 39,917	$ 172,795	$ 202	$ —	$ 212,914
Long-term debt	530,199	666,078	—	—	1,196,277
Deferred income taxes	—	—	—	—	—
Other liabilities	5,998	84,117	—	—	90,115
Payable to parent	(930,994)	930,994	—	—	—
Total shareholders' equity	859,588	(70,928)	269,589	(198,661)	859,588
Total liabilities and shareholders' equity	$ 504,708	$1,783,056	$269,791	$(198,661)	$ 2,358,894

EXCO Resources, Inc.

Consolidating statement of operations

For the year ended December 31, 2010

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 71,584	$ 430,097	$13,545	$ —	$ 515,226
Total revenues	71,584	430,097	13,545	—	515,226
Costs and expenses:					
Oil and natural gas production	15,396	91,423	1,365	—	108,184
Gathering and transportation	—	53,577	1,300	—	54,877
Depreciation, depletion and amortization	26,479	165,041	5,443	—	196,963
Accretion of discount on asset retirement obligations	346	3,408	4	—	3,758
General and administrative	29,571	75,543	—	—	105,114
Gain on divestitures and other operating items	17,286	(526,585)	(573)	—	(509,872)
Total costs and expenses	89,078	(137,593)	7,539	—	(40,976)
Operating income (loss)	(17,494)	567,690	6,006	—	556,202
Other income (expense):					
Interest expense	(38,780)	(6,753)	—	—	(45,533)
Gain on derivative financial instruments	54,631	91,885	—	—	146,516
Equity income	—	—	16,022	—	16,022
Other income (expense)	10,423	(10,096)	—	—	327
Equity in earnings of subsidiaries	664,754	—	—	(664,754)	—
Total other income (expense)	691,028	75,036	16,022	(664,754)	117,332
Income (loss) before income taxes	673,534	642,726	22,028	(664,754)	673,534
Income tax expense	1,608	—	—	—	1,608
Net income (loss)	$671,926	$ 642,726	$22,028	$(664,754)	$ 671,926

EXCO Resources, Inc.

Consolidating statement of operations

For the year ended December 31, 2009

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 142,963	$ 407,542	$ —	$ —	$ 550,505
Midstream	—	35,330	—	—	35,330
Total revenues	142,963	442,872	—	—	585,835
Costs and expenses:					
Oil and natural gas production	44,158	133,471	—	—	177,629
Midstream operating expenses	—	35,580	—	—	35,580
Gathering and transportation	86	18,874	—	—	18,960
Depreciation, depletion and amortization	45,555	175,883	—	—	221,438
Write-down of oil and natural gas properties	279,632	1,013,947	—	—	1,293,579
Accretion of discount on asset retirement obligations	1,628	5,504	—	—	7,132
General and administrative	26,319	72,858	—	—	99,177
Gain on divestitures and other operating items	(332,327)	(344,107)	—	—	(676,434)
Total costs and expenses	65,051	1,112,010	—	—	1,177,061
Operating income (loss)	77,912	(669,138)	—	—	(591,226)
Other income (expense):					
Interest expense	(58,927)	(88,234)	—	—	(147,161)
Gain on derivative financial instruments	54,286	177,739	—	—	232,025
Equity loss	—	—	(69)	—	(69)
Other income (expense)	24,845	(24,719)	—	—	126
Equity in earnings of subsidiaries	(604,241)	—	—	604,241	—
Total other income (expense)	(584,037)	64,786	(69)	604,241	84,921
Income (loss) before income taxes	(506,125)	(604,352)	(69)	604,241	(506,305)
Income tax expense	(9,321)	(180)	—	—	(9,501)
Net income (loss)	(496,804)	(604,172)	(69)	604,241	(496,804)

EXCO Resources, Inc.

Consolidating statement of operations

For the year ended December 31, 2008

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 393,026	$ 1,011,800	$ —	$ —	$ 1,404,826
Midstream	—	85,432	—	—	85,432
Total revenues	393,026	1,097,232	—	—	1,490,258
Costs and expenses:					
Oil and natural gas production	74,025	164,046	—	—	238,071
Midstream operating expenses	—	82,797	—	—	82,797
Gathering and transportation	233	13,973	—	—	14,206
Depreciation, depletion and amortization	122,328	337,986	—	—	460,314
Write-down of oil and natural gas properties	485,468	2,330,367	—	—	2,815,835
Accretion of discount on asset retirement obligations	1,853	4,850	—	—	6,703
General and administrative	15,266	72,302	—	—	87,568
Other operating items	(2,176)	(516)	—	—	(2,692)
Total costs and expenses	696,997	3,005,805	—	—	3,702,802
Operating income (loss)	(303,971)	(1,908,573)	—	—	(2,212,544)
Other income (expense):					
Interest expense	(77,563)	(84,075)	—	—	(161,638)
Gain on derivative financial instruments	254,756	129,633	—	—	384,389
Other income	26,829	(25,540)	—	—	1,289
Equity in earnings of subsidiaries	(1,722,584)	—	—	1,722,584	—
Total other income (expense)	(1,518,562)	20,018	—	1,722,584	224,040
Income (loss) before income taxes	(1,822,533)	(1,888,555)	—	1,722,584	(1,988,504)
Income tax benefit	(89,062)	(165,971)	—	—	(255,033)
Net income (loss)	(1,733,471)	(1,722,584)	—	1,722,584	(1,733,471)
Preferred stock dividends	(76,997)	—	—	—	(76,997)
Net income (loss) available to common shareholders	$(1,810,468)	$(1,722,584)	$ —	$1,722,584	$(1,810,468)

EXCO Resources, Inc.

Consolidating statement of cash flow

For the year ended December 31, 2010

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by (used in) operating activities	$ 70,757	$ 275,768	$ (6,604)	$ —	$ 339,921
Investing Activities:					
Additions to oil and natural gas properties, gathering systems and equipment	(68,478)	(728,018)	(245,475)	—	(1,041,971)
Restricted cash	—	(102,808)	—	—	(102,808)
Investment in equity investments	—	(143,740)	—	—	(143,740)
Proceeds from dispositions	8,624	1,036,209	—	—	1,044,833
Deposits on pending acquisitions	—	(464,151)	—	—	(464,151)
Advances to Appalachia JV	—	(5,017)	—	—	(5,017)
Advances/investments with affiliates	(305,326)	53,247	252,079	—	—
Net cash provided by (used in) investing activities	(365,180)	(354,278)	6,604	—	(712,854)
Financing Activities:					
Borrowings under credit agreements	2,022,437	49,962	—	—	2,072,399
Repayments under credit agreements	(1,945,982)	(24,981)	—	—	(1,970,963)
Proceeds from issuance of 2018 Notes	738,975	—	—	—	738,975
Repayment of 2011 Notes	(444,720)	—	—	—	(444,720)
Proceeds from issuance of common stock, net	23,024	—	—	—	23,024
Payment of common stock dividends	(29,760)	—	—	—	(29,760)
Payment for common shares repurchased	(7,479)	—	—	—	(7,479)
Settlement of derivative financial instruments with a financing element	(907)	—	—	—	(907)
Deferred financing costs and other	(31,814)	—	—	—	(31,814)
Net cash provided by (used in) financing activities	323,774	24,981	—	—	348,755
Net increase (decrease) in cash	29,351	(53,529)	—	—	(24,178)
Cash at beginning of period	47,412	20,995	—	—	68,407
Cash at end of period	$ 76,763	$ (32,534)	$ —	$ —	$ 44,229

EXCO Resources, Inc.

Consolidating statement of cash flow

For the year ended December 31, 2009

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by operating activities	$ 226,012	$ 207,593	$ —	$ —	$ 433,605
Investing Activities:					
Additions to oil and natural gas properties, gathering systems and equipment	(44,434)	(635,660)	(52,602)	—	(732,696)
Restricted cash	—	(58,909)	—	—	(58,909)
Investment in equity investments	—	(47,500)	—	—	(47,500)
Deposit on pending property divestitures	—	—	—	—	—
Proceeds from dispositions	910,891	1,163,489	—	—	2,074,380
Advances/investments with affiliates	(137,305)	84,703	52,602	—	—
Net cash provided by (used in) investing activities	729,152	506,123	—	—	1,235,275
Financing Activities:					
Borrowings under credit agreements	14,979	232,820	—	—	247,799
Repayments under credit agreements	(982,444)	(1,085,227)	—	—	(2,067,671)
Proceeds from issuance of common stock, net	10,361	—	—	—	10,361
Payment of common stock dividends	(10,582)	—	—	—	(10,582)
Settlement of derivative financial instruments with a financing element	56,701	126,251	—	—	182,952
Deferred financing costs and other	(5,385)	(15,086)	—	—	(20,471)
Net cash used in financing activities	(916,370)	(741,242)	—	—	(1,657,612)
Net increase (decrease) in cash	38,794	(27,526)	—	—	11,268
Cash at the beginning of the period	8,618	48,521	—	—	57,139
Cash at end of period	$ 47,412	$ 20,995	$ —	$ —	$ 68,407

EXCO Resources, Inc.

Consolidating statement of cash flow

For the year ended December 31, 2008

(in thousands)	Resources	Guarantor subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by operating activities	$ 286,804	$ 688,162	$ —	$ —	$ 974,966
Investing Activities:					
Property and Midstream acquistions and additions to oil and natural gas properties, gathering systems and equipment	(604,235)	(1,119,887)	—	—	(1,724,122)
Proceeds from dispositions of property and equipment	1,315	14,228	—	—	15,543
Advances/investments with affiliates	(67,897)	67,897	—	—	—
Net cash used in investing activities	(670,817)	(1,037,762)	—	—	(1,708,579)
Financing Activities:					
Borrowings under credit agreements	784,951	915,185	—	—	1,700,136
Repayments under credit agreements	(296,500)	(479,700)	—	—	(776,200)
Settlement of derivative financial instruments with a financing element	(50,135)	(33,468)	—	—	(83,603)
Proceeds from issuance of common stock, net	14,777	—	—	—	14,777
Dividends on preferred stock	(82,831)	—	—	—	(82,831)
Deferred financing costs and other	(700)	(36,337)	—	—	(37,037)
Net cash provided by financing activities	369,562	365,680	—	—	735,242
Net increase (decrease) in cash	(14,451)	16,080	—	—	1,629
Cash at the beginning of the period	23,069	32,441	—	—	55,510
Cash at end of period	$ 8,618	$ 48,521	$ —	$ —	$ 57,139

22. Quarterly financial data (unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2010 and 2009:

(in thousands)	Quarter 1st	2nd	3rd	4th
2010				
Total revenues	$ 130,994	$118,344	$130,990	$134,898
Operating income (loss)(a)	26,904	577,187	9,481	(57,370)
Net income (loss) available to common shareholders(a)	$ 115,568	$564,313	$ 64,896	$ (72,851)
Basic earnings (loss) per share:				
Net income (loss)	$ 0.54	$ 2.66	$ 0.31	$ (0.34)
Weighted average shares	212,086	212,497	212,480	212,791
Diluted earnings (loss) per share:				
Net income (loss)	$ 0.54	$ 2.62	$ 0.30	$ (0.34)
Weighted average shares	215,666	215,498	214,922	212,791
2009				
Total revenues	$ 189,221	$159,194	$130,868	$106,552
Operating income (loss)	(1,283,830)	6,958	464,022	221,624
Net loss available to common shareholders	$(1,099,611)	$ (71,992)	$433,330	$241,469
Basic earnings (loss) per share:				
Net loss	$ (5.21)	$ (0.34)	$ 2.05	$ 1.14
Weighted average shares	210,995	211,089	211,266	211,707
Diluted earnings (loss) per share:				
Net loss	$ (5.21)	$ (0.34)	$ 2.03	$ 1.13
Weighted average shares	210,995	211,089	213,235	214,553

(a) During the fourth quarter of 2010, we incurred losses, including $45.0 million related to estimated post-closing adjustments for our Appalachia JV, $4.8 million fees incurred in connection with our acquisition proposal, and inventory value reductions and certain legal costs.

23. Supplemental information relating to oil and natural gas producing activities (unaudited)

Amounts for the years ended December 31, 2010 and 2009 reflect amendment to oil and gas disclosure requirements set forth in the SEC Release No. 33-8995. FASB also issued Topic 932, which aligned its oil and natural gas reserve estimation and disclosures with the SEC's release.

Presented below are costs incurred in oil and natural gas property acquisition, exploration and development activities:

(in thousands, except per unit amounts)	Amount
2010:	
Proved property acquisition costs	$ 34,042
Unproved property acquisition costs(1)	493,797
Total property acquisition costs	527,839
Development	232,978
Exploration costs(2)	113,617
Lease acquisitions and other(3)	37,518
Capitalized asset retirement costs	1,936
Depreciation, depletion and amortization per Boe	$ 10.55
Depreciation, depletion and amortization per Mcfe	$ 1.75
2009:	
Proved property acquisition costs	$ 6,473
Unproved property acquisition costs(4)	227,161
Total property acquisition costs	233,634
Development	262,786
Exploration costs(5)	37,051
Lease acquisitions and other(6)	106,040
Capitalized asset retirement costs	879
Depreciation, depletion and amortization per Boe	$ 10.37
Depreciation, depletion and amortization per Mcfe	$ 1.75
2008:	
Proved property acquisition costs(7)	$604,723
Unproved property acquisition costs(8)	87,170
Total property acquisition costs	691,893
Development(9)	581,747
Exploration costs	111,426
Lease acquisitions and other(10)	187,134
Capitalized asset retirement costs	19,182
Depreciation, depletion and amortization per Boe	$ 19.10
Depreciation, depletion and amortization per Mcfe	$ 3.18

(1) Reflects acreage acquisitions of Shelby Area of Texas and in DeSoto Parish, Louisiana, all prospective in the Haynesville/Bossier shale play. In addition, we made acreage acquisitions in Appalachia.

(2) Exploration costs in 2010 included approximately $49.8 million incurred in the Marcellus shale play in Appalachia, approximately $40.3 million in non-shale activities in the Kelley's area of East Texas/North Louisiana and $18.5 million in the Haynesville shale play in the Shelby Trough.

(3) Lease acquisition costs in 2010 are net of acreage reimbursements from BG Group totaling $58.3 million.

(4) Reflects fourth quarter acquisitions, consisting primarily of undeveloped acreage in the Haynesville shale play in DeSoto Parish, Louisiana and Caddo Parish, Louisiana.

(5) Exploration costs incurred in 2009 included approximately $27.5 million incurred in the Haynesville shale play in Caddo Parish, Louisiana and Gregg County, Texas, approximately $5.5 million in Appalachia and approximately $1.7 million in Permian.

(6) Lease acquisitions in 2009 include approximately $98.7 million and $6.6 million in the Haynesville/Bossier and Marcellus shale plays, respectively.

(7) Includes $334.3 million and $199.2 million allocated to proved oil and natural gas properties in connection with the Appalachian Acquisition and the Danville Acquisition, respectively.

(8) Includes $44.8 million and $42.4 million allocated to unproved oil and natural gas properties in connection with the Appalachian Acquisition and the Danville Acquisition, respectively.

(9) Exploration costs incurred in 2008 included approximately $52.2 million in Appalachia (Marcellus shale resource play) and approximately $51.2 million in the Haynesville shale resource play in East Texas/North Louisiana. Exploration costs in 2007 were not material.

(10) Lease acquisitions in 2008 include approximately $84.0 million and $55.8 million to lease in the Marcellus and Haynesville shale resource plays, 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 undrilled acreage or from existing wells on which we must make a relatively major expenditure for recompletion or secondary recovery operations. All of our reserves are located onshore in the continental United States of America.

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

(in thousands)	Oil (Bbls)	Natural Gas (Mcf)	Mcfe(1)
December 31, 2007	20,930	1,739,550	1,865,130
Purchase of reserves in place	635	175,679	179,489
New discoveries and extensions(2)	5,040	259,801	290,041
Revisions of previous estimates(3)			
Due to changes in price	(2,407)	(93,015)	(107,457)
Due to other factors	(1,060)	(130,605)	(136,965)
Production	(2,236)	(131,159)	(144,575)
Sales of reserves in place	(101)	(5,113)	(5,719)
December 31, 2008	20,801	1,815,138	1,939,944
Purchase of reserves in place	—	8,065	8,065
New discoveries and extensions(4)	202	240,844	242,056
Revisions of previous estimates(5)			
Due to changes in price	(1,482)	(249,948)	(258,840)
Due to other factors	124	(54,613)	(53,869)
Production	(1,571)	(118,735)	(128,161)
Sales of reserves in place(6)	(12,556)	(715,023)	(790,359)
December 31, 2009	5,518	925,728	958,836
Purchase of reserves in place	—	30,047	30,047
New discoveries and extensions(7)	1,631	635,841	645,627
Revisions of previous estimates(8)			
Due to changes in price	751	48,630	53,136
Due to other factors	549	63,089	66,383
Production	(688)	(107,878)	(112,006)
Sales of reserves in place(9)	(403)	(140,504)	(142,922)
December 31, 2010(10)	7,358	1,454,953	1,499,101

Estimated Quantities of Proved Reserves

(in thousands)	Oil (Bbls)	Natural Gas (Mcf)	Mcfe(1)
Proved developed:			
December 31, 2010	4,633	793,777	821,575
December 31, 2009	3,505	622,160	643,190
December 31, 2008	14,815	1,354,729	1,443,619
Proved undeveloped:			
December 31, 2010	2,725	661,176	677,526
December 31, 2009	2,013	303,568	315,646
December 31, 2008	5,986	460,409	496,325

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

(2) New discoveries and extensions between December 31, 2007 and December 31, 2008 include 167,381 Mmcfe in East Texas/North Louisiana, 67,161 Mmcfe in Appalachia, 34,833 Mmcfe in Permian and 20,666 Mmcfe in other areas.

(3) Total revisions between December 31, 2007 and December 31, 2008 include negative revisions of 107,457 Mmcfe due to price changes and negative revisions of 136,965 Mmcfe due to changes other than price, particularly in our Appalachia and Permian regions.

(4) New discoveries and extensions between December 31, 2008 and December 31, 2009 include 238,475 Mmcfe in East Texas/North Louisiana (primarily in the Haynesville shale play), 2,303 Mmcfe in Appalachia and 1,279 Mmcfe in Permian.

(5) Total revisions of 312,709 Mmcfe reflect negative revisions attributable to price of 258,840 Mmcfe and 65,008 Mmcfe of downward performance revisions, which occurred primarily in our Appalachia region. The other than price downward revisions were offset by positive performance revisions of 11,139 Mmcfe, which occurred primarily in our East Texas/North Louisiana region.

(6) Sales of reserves in place in 2009 reflect 346,283 Mmcfe in East Texas/North Louisiana (including the BG Upstream Transaction), 292,158 Mmcfe in the Mid-Continent area, 121,578 Mmcfe in Appalachia and 30,340 Mmcfe in Permian.

(7) New discoveries and extensions in 2010 include 614,508 Mmcfe in East Texas/North Louisiana, primarily in the Haynesville shale play; 14,699 in Appalachia, of which 10,285 Mmcfe was in the Marcellus shale play; and 16,420 in Permian.

(8) Total net positive revisions of 119,519 Mmcfe reflect upward revisions attributable to price of 53,136 Mmcfe and positive performance revisions of 75,205 Mmcfe and 13,711 Mmcfe in East Texas/North Louisiana and Permian, respectively. These were offset by downward performance revisions of 22,533 Mmcfe in Appalachia related to shallow reserves.

(9) Sales of reserve in place in 2010 are primarily attributable to the Appalachia JV transaction with BG Group which resulted in the sale of 133,123 Mmcfe.

(10) The above reserves do not include our equity interest in OPCO, which represents 0.04% (575 Mmcfe) of our Consolidated Proved Reserves at December 31, 2010 and a standardized Measure of $405 thousand, or 0.03%, of our Consolidated Standard Measure.

Standardized measure of discounted future net cash flows

We have summarized the Standardized Measure related to our proved oil, natural gas, and NGL reserves. We have based the following summary on a valuation of Proved Reserves using discounted cash flows based on prices as prescribed by the SEC, 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.

(in thousands)	Amount
Year ended December 31, 2010:	
Future cash inflows	$ 6,909,755
Future production costs	2,513,808
Future development costs	1,630,946
Future income taxes	305,115
Future net cash flows	2,459,886
Discount of future net cash flows at 10% per annum	1,236,448
Standardized measure of discounted future net cash flows	$ 1,223,438
Year ended December 31, 2009:	
Future cash inflows	$ 3,509,227
Future production costs	1,337,898
Future development costs	695,174
Future income taxes (1)	—
Future net cash flows	1,476,155
Discount of future net cash flows at 10% per annum	728,452
Standardized measure of discounted future net cash flows	$ 747,703
Year ended December 31, 2008:	
Future cash inflows	$11,045,544
Future production costs	3,650,402
Future development costs	1,732,321
Future income taxes	649,807
Future net cash flows	5,013,014
Discount of future net cash flows at 10% per annum	2,776,720
Standardized measure of discounted future net cash flows	$ 2,236,294

(1) Due to a 32.2% reduction in price for natural gas in 2009 from 2008, estimated future net cash flows, combined with available net operating loss carry-forwards resulted in no estimated future taxable income as of December 31, 2009.

During recent years, prices paid for oil and natural gas have fluctuated significantly. The reference prices at December 31, 2010, 2009 and 2008 used in the above table, were $79.43, $61.18 and $44.60 per Bbl of oil, respectively, and $4.38, $3.87 and $5.71 per Mmbtu of natural gas, respectively, in each case adjusted for historical differentials. The prices for 2008 were based on the spot price as of December 31, 2008 for oil and natural gas. The price for oil and natural gas used at December 31, 2010 and 2009 reflects the new SEC rules effective December 31, 2009 requiring the use of simple average of the first day of the month price for the previous twelve month period.

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

(in thousands)	Amount
Year ended December 31, 2010:	
Sales and transfers of oil and natural gas produced	$ (353,206)
Net changes in prices and production costs	231,551
Extensions and discoveries, net of future development and production costs	512,470
Development costs during the period	44,537
Changes in estimated future development costs	(50,151)
Revisions of previous quantity estimates	207,657
Sales of reserves in place	(82,445)
Purchase of reserves in place	51,942
Accretion of discount before income taxes	74,770
Changes in timing and other	(28,307)
Net change in income taxes	(133,083)
Net change	$ 475,735
Year ended December 31, 2009:	
Sales and transfers of oil and natural gas produced	$ (356,746)
Net changes in prices and production costs	(915,030)
Extensions and discoveries, net of future development and production costs	275,622
Development costs during the period	80,218
Changes in estimated future development costs	373,336
Revisions of previous quantity estimates	(329,573)
Sales of reserves in place	(1,028,622)
Purchase of reserves in place	472
Accretion of discount before income taxes	240,507
Changes in timing and other	(66,011)
Net change in income taxes	237,236
Net change	$(1,488,591)
Year ended December 31, 2008:	
Sales and transfers of oil and natural gas produced, net of production costs	$(1,156,723)
Net changes in prices and production costs	(857,254)
Extensions and discoveries, net of future development and production costs	243,912
Development costs during the period	287,975
Changes in estimated future development costs	(191,993)
Revisions of previous quantity estimates	(393,359)
Sales of reserves in place	(8,490)
Purchase of reserves in place	203,707
Accretion of discount before income taxes	388,395
Changes in timing and other	11,460
Net change in income taxes	589,777
Net change	$ (882,593)

Costs not subject to amortization

The following table summarizes the categories of costs comprising the amount of unproved properties not subject to amortization by the year in which such costs were incurred. There are no individually significant properties or significant development projects included in costs not being amortized. The majority of the evaluation activities are expected to be completed within one to seven years.

(in thousands)	Total	2010	2009	2008	2007 and prior
Property acquisition costs	$561,360	$290,331	$203,471	$11,935	$55,623
Exploration and development	20,632	20,632	—	—	—
Capitalized interest	17,417	16,970	447	—	—
Total	$599,409	$327,933	$203,918	$11,935	$55,623

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure controls and procedures. Pursuant to Rule 13a-15(b) under the Exchange Act, management has evaluated, under the supervision and with the participation of our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act), as of the end of the period covered by this report. Based on this evaluation, our principal executive officer and principal financial officer have concluded that EXCO's disclosure controls and procedures were effective as of December 31, 2010 to ensure that information that is required to be disclosed by EXCO in the reports it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms and (ii) accumulated and communicated to EXCO's management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's report on internal control over financial reporting. EXCO's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) or 15d-15(f) of the Exchange Act). Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of an internal control system in future periods can change with conditions. Management's annual report of internal control over financial reporting and the audit report on our internal control over financial reporting of our independent registered public accounting firm, KPMG LLP, are included in Item 8 of this annual report on Form 10-K and are incorporated by reference herein.

Changes in internal control over financial reporting. EXCO's management assessed the effectiveness of EXCO's internal control over financial reporting as there were no changes in EXCO's internal control over financial reporting that occurred during the fiscal quarter ended December 31, 2010 that have materially affected, or are reasonably likely to materially affect, EXCO's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this Item 11 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

The information required in response to this Item 12 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required in response to this Item 13 is incorporated herein by reference to our definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A of the Securities Exchange Act of 1934 not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

ITEM 14. PRINCIPAL 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 Annual Report on Form 10-K.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) See Part II—Item 8. Financial Statements and Supplementary Data in this Annual Report on Form 10-K.

(a)(2) None.

(a)(3) See “Index to Exhibits” for a description of our exhibits.

(b) See “Index to Exhibits” for a description of our exhibits.

(c) None.

SIGNATURE PAGE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 24, 2011

EXCO RESOURCES, INC.
(Registrant)

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated.

Date: February 24, 2011

/s/ DOUGLAS H. MILLER
Douglas H. Miller
Director, Chairman and Chief Executive Officer

/s/ STEPHEN F. SMITH
Stephen F. Smith
Director, Vice Chairman, President and
Chief Financial Officer

/s/ MARK E. WILSON
Mark E. Wilson
Vice President, Chief Accounting Officer and Controller

/s/ JEFFREY D. BENJAMIN
Jeffrey D. Benjamin
Director

/s/ VINCENT J. CEBULA
Vincent J. Cebula
Director

/s/ EARL E. ELLIS
Earl E. Ellis
Director

/s/ B. JAMES FORD
B. James Ford
Director

/s/ MARK F. MULHERN
Mark F. Mulhern
Director

/s/ BOONE PICKENS
Boone Pickens
Director

/s/ JEFFREY S. SEROTA

Jeffrey S. Serota
Director

/s/ ROBERT L. STILLWELL

Robert L. Stillwell
Director

INDEX TO EXHIBITS

Exhibit Number	Description of Exhibits
2.1	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Operating Company, LP, as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.2	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Resources, Inc., as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.3	Purchase and Sale Agreement, dated June 29, 2009, by and among EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.4	Contribution Agreement, dated August 5, 2009, by and among Vaughan Holding Company, LLC, EXCO Operating Company, LP and BG US Gathering Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11, 2009 and incorporated by reference herein.
2.5	First Amendment, dated July 13, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
2.6	Second Amendment, dated August 5, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11 , 2009 and incorporated by reference herein.
2.7	Purchase and Sale Agreement, dated September 29, 2009, by and between EXCO—North Coast Energy, Inc., Inc., as seller, and EnerVest Energy Institutional Fund XI-A, L.P., EnerVest Energy Institutional Fund XI-WI, L.P., and EV Properties, L.P., as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
2.8	Purchase and Sale Agreement, dated September 30, 2009, by and between EXCO Resources, Inc., as seller, and Sheridan Holding Company I, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
2.9	Membership Interest Transfer Agreement, dated as of May 9, 2010, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
2.10	First Amendment to Membership Interest Transfer Agreement, dated as of June 1, 2010, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed herewith.
2.11	Second Amendment to Membership Interest Transfer Agreement, dated as of June 30, 2010, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed herewith.
2.12	Amendment to Membership Interest Transfer Agreement, dated as of November 24, 2010, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed herewith.
2.13	Fourth Amendment to Membership Interest Transfer Agreement, dated as of January 6, 2011, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed herewith.
2.14	Fifth Amendment to Membership Interest Transfer Agreement, dated as of January 13, 2011, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed herewith.

Exhibit Number	Description of Exhibits
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	Articles of Amendment to the 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 August 30, 2007 and filed on September 5, 2007 and incorporated by reference herein.
3.3	Second Amended and Restated Bylaws of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 4, 2009 and filed on March 6, 2009 and incorporated by reference herein.
3.4	Statement of Designation of Series A-l 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.5	Statement of Designation of Series A-2 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.6	Statement of Designation of Series B 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.7	Statement of Designation of Series C 7.0% Cumulative Convertible Perpetual Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.8	Statement of Designation of Series A-l Hybrid Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.9	Statement of Designation of Series A-2 Hybrid Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
3.10	Statement of Designation of Series A Junior Participating Preferred Stock of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K dated January 12, 2011 and filed on January 13, 2011 and incorporated by reference herein.
4.1	Indenture, dated September 15, 2010, by and between EXCO Resources, Inc. and Wilmington Trust Company, as trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated September 10, 2010 and filed on September 15, 2010 and incorporated by reference herein.
4.2	First Supplemental Indenture, dated September 15, 2010, by and among EXCO Resources, Inc., certain of its subsidiaries and Wilmington Trust Company, as trustee, including the form of 7.500% Senior Notes due 2018, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated September 10, 2010 and filed on September 15, 2010 and incorporated by reference herein.
4.3	Specimen Stock Certificate for EXCO's common stock, filed as an Exhibit to EXCO's Amendment No. 2 to the Form S-l (File No. 333-129935) filed on January 27, 2006 and incorporated by reference herein.
4.4	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-l (File No. 333-129935) filed on January 6, 2006 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
4.5	Rights Agreement, dated as of January 12, 2011, by and between EXCO Resources, Inc. and Continental Stock Transfer & Trust Company, as Rights Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K dated January 12, 2011 and filed on January 13, 2011 and incorporated by reference herein.
10.1	Underwriting Agreement, dated September 10, 2010, by and among EXCO Resources, Inc., certain of its subsidiaries, and J.P. Morgan Securities LLC, on behalf of itself and the other underwriters listed on Schedule 1 thereto, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated September 10, 2010 and filed on September 15, 2010 and incorporated by reference herein.
10.2	Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.3	Form of Incentive Stock Option Agreement for the EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.4	Form of Nonqualified Stock Option Agreement for the EXCO Resources, Inc. 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.5	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.*
10.6	Third Amended and Restated EXCO Resources, Inc. Severance Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.7	Amended and Restated 2007 Director Plan of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.
10.8	Amendment Number One to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc., filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2009 filed February 24, 2010 and incorporated herein by reference.
10.9	Letter Agreement, dated March 28, 2007, with OCM Principal Opportunities Fund IV, L.P. and OCM EXCO Holdings, LLC, filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
10.10	Letter Agreement, dated March 28, 2007, with Ares Corporate Opportunities Fund, ACOF EXCO, L.P., ACOF EXCO 892 Investors, L.P., Ares Corporate Opportunities Fund II, L.P., Ares EXCO, L.P. and Ares EXCO 892 Investors, L.P, filed as an Exhibit to EXCO's Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
10.11	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Operating Company, LP, as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
10.12	Purchase and Sale Agreement, dated June 28, 2009, by and between EXCO Resources, Inc., as seller, and Encore Operating, LP, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
10.13	Purchase and Sale Agreement, dated June 29, 2009, by and among EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
10.14	Amendment Number One to the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, filed as an exhibit to EXCO's Current Report on Form 8-K, dated June 4, 2009 and filed on June 10, 2009 and incorporated by reference herein.
10.15	Joint Development Agreement, dated August 14, 2009, by and among BG US Production Company, LLC, EXCO Operating Company, LP and EXCO Production Company, LP, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 11, 2009 and filed on August 17, 2009 and incorporated by reference herein.
10.16	Amendment to Joint Development Agreement, dated February 1, 2011, by and among BG US Production Company, LLC and EXCO Operating Company, LP, filed herewith.
10.17	Contribution Agreement, dated August 5, 2009, by and among Vaughan Holding Company, LLC, EXCO Operating Company, LP and BG US Gathering Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11, 2009 and incorporated by reference herein.
10.18	Amended and Restated Limited Liability Company Agreement of TGGT Holdings, LLC, dated August 14, 2009, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 11, 2009 and filed on August 17, 2009 and incorporated by reference herein.
10.19	First Amendment to Amended and Restated Limited Liability Company Agreement of TGGT Holdings, LLC, dated January 31, 2011, filed herewith.
10.20	First Amendment, dated July 13, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q, filed on August 6, 2009 and incorporated by reference herein.
10.21	Second Amendment, dated August 5, 2009, to Purchase and Sale Agreement by and between EXCO Operating Company, LP and EXCO Production Company, LP, as sellers, and BG US Production Company, LLC, as buyer, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 5, 2009 and filed on August 11, 2009 and incorporated by reference herein.
10.22	Purchase and Sale Agreement, dated September 29, 2009, by and between EXCO - North Coast Energy, Inc., Inc., as seller, and EnerVest Energy Institutional Fund XI-A, L.P., EnerVest Energy Institutional Fund XI-WI, L.P., and EV Properties, L.P., as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
10.23	Purchase and Sale Agreement, dated September 30, 2009, by and between EXCO Resources, Inc., as seller, and Sheridan Holding Company I, LLC, as buyer, filed as an exhibit to EXCO's Quarterly Report on Form 10-Q, filed on November 4, 2009 and incorporated by reference herein.
10.24	Joint Development Agreement, dated as of June 1, 2010, by and among EXCO Production Company (PA), LLC, EXCO Production Company (WV), LLC, BG Production Company, (PA), LLC, BG Production Company, (WV), LLC and EXCO Resources (PA), LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.25	Amendment to Joint Development Agreement, dated February 4, 2011, by and among EXCO Production Company (PA), LLC, EXCO Production Company (WV), LLC, BG Production Company, (PA), LLC, BG Production Company, (WV), LLC and EXCO Resources (PA), LLC, filed herewith.

Exhibit Number	Description of Exhibits
10.26	Second Amended and Restated Limited Liability Company Agreement of EXCO Resources (PA), LLC, dated June 1, 2010, by and among EXCO Holding (PA), Inc., BG US Production Company, LLC and EXCO Resources (PA), LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.27	Second Amended and Restated Limited Liability Company Agreement of Appalachia Midstream, LLC, dated June 1, 2010, by and among EXCO Holding (PA), Inc., BG US Production Company, LLC and Appalachia Midstream, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.28	Letter Agreement, dated June 1, 2010 and effective as of May 9, 2010, by and between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.29	Membership Interest Transfer Agreement, dated as of May 9, 2010, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.30	First Amendment to Membership Interest Transfer Agreement, dated as of June 1, 2010, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed herewith as Exhibit 2.10.
10.31	Second Amendment to Membership Interest Transfer Agreement, dated as of June 30, 2010, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed herewith as Exhibit 2.11.
10.32	Amendment to Membership Interest Transfer Agreement, dated as of November 24, 2010, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed herewith as Exhibit 2.12.
10.33	Fourth Amendment to Membership Interest Transfer Agreement, dated as of January 6, 2011, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed herewith as Exhibit 2.13.
10.34	Fifth Amendment to Membership Interest Transfer Agreement, dated as of January 13, 2011, between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed herewith as Exhibit 2.14.
10.35	Guaranty, dated May 9, 2010, by BG Energy Holdings Limited in favor of EXCO Holding (PA), Inc., EXCO Production Company (PA), LLC and EXCO Production Company (WV), LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.36	Guaranty, dated May 9, 2010, by EXCO Resources, Inc. in favor of BG US Production Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.37	Guaranty, dated June 1, 2010, by BG North America, LLC in favor of (i) EXCO Production Company (PA), LLC, EXCO Production Company (WV), LLC and EXCO Resources (PA), LLC; and (ii) EXCO Resources (PA), LLC and EXCO Holding (PA), Inc, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.38	Guaranty, dated June 1, 2010, by EXCO Resources, Inc., in favor of: (i) BG Production Company (PA), LLC, BG Production Company (WV), LLC and EXCO Resources (PA), LLC; and (ii) EXCO Resources (PA), LLC and BG US Production Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.

Exhibit Number	Description of Exhibits
10.39	Credit Agreement, dated as of April 30, 2010, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Securities Inc., as Sole Book runner and Lead Arranger, Wells Fargo Securities, LLC, as Co-Lead Arranger, Bank of America, N.A. and BNP Paribas, as Co-Lead Arrangers and Co-Syndication Agents, Royal Bank of Canada, as Co-Lead Arranger and Co-Documentation Agent, Wells Fargo Bank, National Association, as Co-Documentation Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated July 16, 2010 and filed on July 22, 2010 and incorporated by reference herein.
10.40	First Amendment to Credit Agreement, dated as of July 16, 2010, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and Bank of America, N.A. and BNP Paribas, as Co-Lead Arrangers and Co-Syndication Agents, Royal Bank of Canada, as Co-Lead Arranger and Co-Documentation Agent, Wells Fargo Bank, National Association, as Co-Documentation Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated July 16, 2010 and filed on July 22, 2010 and incorporated by reference herein.
10.41	Second Amendment to Credit Agreement, dated as of September 15, 2010, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and Bank of America, N.A. and BNP Paribas, as Co-Lead Arrangers and Co-Syndication Agents, Royal Bank of Canada, as Co-Lead Arranger and Co-Documentation Agent, and Wells Fargo Bank, National Association, as Co-Documentation Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated September 10, 2010 and filed on September 15, 2010 and incorporated by reference herein.
10.42	Form of Director Indemnification Agreement, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 10, 2010 and filed on November 12, 2010 and incorporated by reference herein.
10.43	Asset Purchase Agreement, dated December 15, 2010, among EXCO Holding (PA), Inc., Chief Oil & Gas LLC, Chief Exploration & Development LLC and Radler 2000 Limited Partnership, filed herewith.
10.44	Credit Agreement, dated January 31 , 2011, by and among TGGT Holdings, LLC, its subsidiaries, as borrowers (or guarantor as to one TGGT subsidiary), JPMorgan Chase Bank, N.A., as administrative agent, J.P. Morgan Securities Inc., as sole bookrunner and co-lead arranger, BNP Paribas, Citibank, N.A., The Royal Bank of Scotland PLC and Wells Fargo Securities, LLC, as co-lead arrangers, and the lenders named therein, filed herewith.
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-l (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-l (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 Lee Keeling and Associates, Inc., filed herewith.

Exhibit Number	Description of Exhibits
23.3	Consent of Haas Petroleum Engineering Services, 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.
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of Chief Executive Officer and Chief Financial Officer of EXCO Resources, Inc., filed herewith.
99.1	2010 Report of Haas Petroleum Engineering Services, Inc., filed herewith.
99.2	2010 Reports of Lee Keeling and Associates, Inc., filed herewith.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Definition Linkbase Document
101.LAB**	XBRL Taxonomy Label Linkbase Document
101.PRE**	XBRL Taxonomy Presentation Linkbase Document

* These exhibits are management contracts.

** Furnished with this report. In accordance with Rule 406T of Regulation S-T, the information in these exhibits shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to liability under that section, and shall not be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933, as amended, except as expressly set forth by specific reference in such filing.

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

FORM 10-K/A
Amendment No. 1

(Mark One)

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

For the Fiscal Year Ended December 31, 2010

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 001-32743

EXCO RESOURCES, INC.
(Exact name of Registrant as specified in its charter)

Texas	**74-1492779**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
12377 Merit Drive, Suite 1700, LB 82 Dallas, Texas	**75251**
(Address of principal executive offices)	(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
Rights to Purchase Series A Junior Participating Preferred Stock	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 whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant is required to submit and post such files). Yes ☒ No ☐

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

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

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

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

As of April 15, 2011, the registrant had 213,780,898 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 the registrant's common stock held by non-affiliates was $2,158,830,000.

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

EXCO RESOURCES, INC.

2010 ANNUAL REPORT ON FORM 10-K/A

TABLE OF CONTENTS

PART III

PART IV

EXPLANATORY NOTE

EXCO Resources, Inc. is filing this Amendment No. 1 on Form 10-K/A to its Annual Report on Form 10-K for the fiscal year ended December 31, 2010, filed on February 24, 2011 (the "Form 10-K"), to provide the additional information required by Part III of Form 10-K. This Amendment No. 1 on Form 10-K/A does not change the previously reported financial statements or any of the other disclosures contained in Part I or Part II of the Form 10-K. References to "EXCO," "us," "we," "Company" and "our" in this report refer to EXCO Resources, Inc., together with its subsidiaries.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Directors

The current size of the Board of Directors of the Company is ten. Our directors serve until the next annual meeting of shareholders or until their respective successors have been duly elected and qualified. Pursuant to certain letter agreements that the Company entered into with funds managed by Oaktree Capital Management, LP (collectively, the “Oaktree Funds”) and Ares Management LLC (together with its affiliates, “Ares”) at the closing in March 2007 of a transaction in which we sold shares of preferred stock to certain investors (which preferred stock was converted into common stock during 2008), Oaktree and Ares, respectively, each have the right to nominate one director for election at any annual meeting of shareholders so long as Oaktree and Ares, respectively, each beneficially own at least 10,000,000 shares of Common Stock. As of the record date for last year’s annual meeting, Oaktree and Ares each owned in excess of 10,000,000 shares of Common Stock. As a result, Messrs. Ford and Serota were nominated by Oaktree and Ares, respectively, as well as by our Board of Directors, for election at last year’s annual meeting.

On October 29, 2010, our Chairman and Chief Executive Officer, Douglas H. Miller, presented a letter to our Board of Directors indicating an interest in acquiring all of the outstanding shares of our stock not already owned by Mr. Miller for a cash purchase price of $20.50 per share. The proposal does not represent a definitive offer and there is no assurance that a definitive offer will be made or accepted, that any agreement will be executed or that any transaction will be consummated.

Our Board of Directors established a special committee on November 4, 2010 comprised of two of our independent directors to, among other things, evaluate and determine the Company’s response to the October 29, 2010 proposal. The special committee retained Kirkland & Ellis LLP and Jones Day as its counsel and Barclays Capital, Inc. and Evercore Partners as its financial advisors to assist it in, among other things, evaluating and determining the Company’s response to the proposal. See “Note 19. Acquisition Proposal” of the notes to our consolidated financial statements for further information regarding the proposal and for information regarding certain lawsuits against the Company or members of the Board of Directors in connection with the proposal.

The following table sets forth the name, age and positions of each director currently serving on our Board of Directors:

Name	Age	Position
Douglas H. Miller	63	Chairman and Chief Executive Officer
Stephen F. Smith	69	Vice Chairman, President and Chief Financial Officer
Jeffrey D. Benjamin(1)(2)(3)	49	Director
Vincent J. Cebula(2)(3)(4)	47	Director
Earl E. Ellis(2)	69	Director
B. James Ford(2)(3)	42	Director
Mark Mulhern(1)(2)(4)	51	Director
T. Boone Pickens	82	Director
Jeffrey S. Serota(1)(2)(3)	45	Director
Robert L. Stillwell(2)(3)	74	Director

(1) Member of the audit committee.
(2) Member of the compensation committee.
(3) Member of the nominating and corporate governance committee.
(4) Member of the special committee.

The biographies of our directors are as follows:

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.

Mr. Miller has extensive experience and knowledge of the Company, the oil and gas industry and capital markets as well as significant strategic and executive leadership experience. Since he is responsible for, and familiar with, our day-to-day operations and implementation of our overall strategy, his insights into our performance and into the industry are critical to board discussions and to our success. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—Transactions with Related Persons—Corporate use of personal aircraft" for a description of certain related person transactions involving Mr. Miller.

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. Mr. Smith began serving as our Chief Financial Officer in June 2009. 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.

Mr. Smith has extensive experience and knowledge of the Company and the oil and gas industry as well as significant accounting, finance and executive leadership experience. Since he is responsible for, and familiar with, our day-to-day operations and financial condition, his insights into our performance and into the industry are critical to board discussions and to our success. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—Transactions with Related Persons—Subcontractor relationship with Jeff Smith" for a description of a related person transaction involving Mr. Smith's son.

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. Since June 2008, Mr. Benjamin has been a Senior Advisor to Cyrus Capital Partners, LP. From September 2002 until June 2008, Mr. Benjamin was a Senior Advisor to Apollo Management, LP. With his history at Apollo Management and Cyrus Capital Partners, Mr. Benjamin has extensive financial, capital markets and strategic experience. Mr. Benjamin is currently a director of Caesars Entertainment Corporation, Chemtura Corporation and Spectrum Group International, Inc. During the past five years, Mr. Benjamin also served on the board of directors of Chiquita Brands International, Inc., Dade Behring Holdings, Inc., Goodman Global, Inc. and Virgin Media Inc.

In connection with his service as a director of eight public companies other than EXCO over the past nine years, Mr. Benjamin served on five compensation committees (including two as chairman), five audit committees and five nominating and corporate governance committees (including two as chairman), all of which provide him with important insights into corporate governance, financial reporting and oversight, executive compensation and board functions. In addition, Mr. Benjamin has deep knowledge of the Company and its business, having served on our and our affiliates' boards since October 2005 and prior to that from 1998 through 2003. Mr. Benjamin holds a Master of Science (MBA) in Management from the Sloan School of Management at MIT, with a concentration in Finance, and has 25 years of investment banking and investment management experience.

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 Inc. from July 2003 until October 2005. Mr. Cebula is a Managing Director of Jefferies Capital Partners, a private equity investment firm. Prior to joining Jefferies in November 2007, Mr. Cebula was a Managing Director of Oaktree Capital Management, L.P., a global investment firm, and its predecessor where he was a founding member of Oaktree's Principal Opportunities Funds since

1994. During the past five years, Mr. Cebula served as a director of publicly traded Cherokee International Corporation. During the past sixteen years, Mr. Cebula has been a director of three publicly traded companies and six private companies, and has had responsibility for the investment and oversight of over $1.5 billion of capital deployed in the equity and debt securities of over twenty companies in many industries including oil and gas, which was the largest portion of these investment assets.

Mr. Cebula's background and experience provide him with extensive investment, capital markets and strategic experience, as well as important insights into corporate governance, executive compensation and board functions. In addition, Mr. Cebula has deep knowledge of the Company and its business, having served on our and our affiliates' boards since 2003.

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 Whole Harvest Foods, formerly Carolina Soy Products, an edible oil 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, or the NYSE. He had been associated with Benjamin Jacobson & Sons, LLC from 1977 to 2001 and was a member of the NYSE for over thirty years.

Mr. Ellis's background and experience provide him with extensive investment, capital markets and executive leadership experience, familiarity with our industry and important insights into corporate governance, financial reporting and oversight, executive compensation and board functions. In addition, Mr. Ellis has deep knowledge of the Company and its business, having served on our and our affiliates' boards since October 2005 and prior to that from 1998 through 2003. Mr. Ellis is a graduate of Baylor University, with a degree in economics.

B. James Ford became one of our directors on December 1, 2007. Mr. Ford is a Managing Director of Oaktree where he has worked since 1996. Mr. Ford is a co-portfolio manager of Oaktree's Principal Opportunities Funds, which invest in controlling and minority positions in private and public companies. Mr. Ford serves on the Board of Directors of Crimson Exploration, Inc. as well as a number of private companies and not-for-profit entities. He is also an active member of the Children's Bureau Board of Directors and serves as a trustee for the Stanford Graduate School of Business Trust. Prior to becoming portfolio manager, Mr. Ford led the group's media and energy investing. Mr. Ford joined Oaktree in 1996 following graduation from the Stanford Graduate School of Business. Previously, Mr. Ford served as a consultant at McKinsey & Co., an analyst at PaineWebber Incorporated, and as an asset manager/acquisitions analyst at National Partnership Investments Corp., a real estate investment firm.

Mr. Ford's background and experience provide him with extensive investment, capital markets and strategic experience, as well as important insights into corporate governance and board functions. In addition to his graduate degree, Mr. Ford received a B.A. degree in Economics from the University of California at Los Angeles.

Mark Mulhern became one of our directors on February 1, 2010. Mr. Mulhern is chief financial officer of Progress Energy, Inc. and oversees its financial services group. Mr. Mulhern joined Progress Energy in 1996 as vice president and controller. Before joining Progress Energy, Mr. Mulhern was the chief financial officer at Hydra Co Enterprises, the independent power subsidiary of Niagara Mohawk. He also spent eight years at PricewaterhouseCoopers LLP in Syracuse, New York, serving a wide variety of manufacturing and service businesses. Mr. Mulhern serves on the Edison Electric Institute Financial Executive Advisory Committee and is on the board of directors of Habitat for Humanity of North Carolina. He is a 1982 graduate of St. Bonaventure University. Mr. Mulhern is a certified public accountant, a certified management accountant and a certified internal auditor.

Mr. Mulhern's background and experience provide him with extensive knowledge of the energy industry as well as significant finance and executive leadership experience and important insights into financial reporting and oversight, executive compensation and board functions. Mr. Mulhern has also completed the nuclear executive program at the Massachusetts Institute of Technology.

T. 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 Fuels Corp. 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 Fuels Corp. 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 Petroleum Co. from its inception until his departure in 1996.

Mr. Pickens' background and experience provide him with extensive knowledge of the oil and gas industry as well as significant investment and strategic leadership experience and important insights into corporate governance and board functions. In addition, Mr. Pickens has deep knowledge of the Company and its business, having served on our and our affiliates' boards from 1998 through 2003 and since 2005.

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. He has served as a Senior Partner of Ares Management LLC, an alternative asset investment firm, since September 1997. Prior to joining Ares, Mr. Serota worked at Bear Stearns from March 1996 to September 1997, where he specialized in providing investment banking services to financial sponsor clients of the firm. He currently serves on the board of directors of SandRidge Energy, Inc., WCA Waste Corporation and LyondellBasell Industries N.V. and previously served on the board of directors of Douglas Dynamics, Inc. from 2004 until October 2010. Mr. Serota has over 20 years of experience managing investments in, and serving on the boards of directors of, companies operating in various industries, including in the oil and natural gas exploration and production industries.

Mr. Serota's background and experience provide him with extensive investment, capital markets and strategic experience, as well as important insights into corporate governance, financial reporting and oversight, executive compensation and board functions. Mr. Serota received a Bachelor of Science degree in Economics from the University of Pennsylvania's Wharton School of Business and received a Master of Business Administration degree from UCLA's Anderson School of Management.

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.

Mr. Stillwell's background and experience provide him with extensive knowledge of the oil and gas industry as well as significant legal experience and important insights into corporate governance, executive compensation and board functions.

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

Audit Committee

Our Board of Directors has an audit committee, which 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), Mulhern and

Serota, each of whom is independent within the meaning of applicable Securities and Exchange Commission (the "SEC") and NYSE rules. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—Director Independence." On February 22, 2010, Mr. Ellis rotated off of the audit committee and Mr. Mulhern joined the audit committee. The Board of Directors has designated each of Messrs. Benjamin and Mulhern as an audit committee financial expert, as currently defined under the SEC rules implementing the Sarbanes-Oxley Act of 2002. 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.

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 website, www.excoresources.com, or by contacting us at the address appearing on the first page of this Annual Report on Form 10-K 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 website at www.excoresources.com.

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 "—Directors."

Name	Age	Position
Harold L. Hickey	55	Vice President and Chief Operating Officer
William L. Boeing	56	Vice President, General Counsel and Secretary
Mark E. Wilson	51	Vice President, Chief Accounting Officer and Controller

The biographies of our executive officers other than Messrs. Douglas H. Miller and Stephen F. Smith are as follows:

Harold L. Hickey became our Vice President and Chief Operating Officer in October 2005. From January 2004 until October 2005, 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 one of our outside law firms, 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 and Divisional Managers of Our Company

Michael R. Chambers Sr., age 55, became our Vice President of Operations in February 2007 and also currently serves as the Vice President and General Manager of our East Texas/North Louisiana Division. 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.

W. Justin Clarke, age 35, became our Assistant General Counsel and Chief Compliance Officer in January 2007. From September 2001 until January 2007, Mr. Clarke served as an associate at one of our outside law firms, Haynes and Boone, LLP, in Dallas, Texas.

Steve Estes, age 56, became our Vice President of Marketing in June 2010. Prior to then, Mr. Estes served as Director of Marketing for us since July 2007. Mr. Estes held several positions with Union Pacific Resources and Anadarko Petroleum before joining us, most recently Regional Manager of Gas Marketing from 2002 until 2007. Mr. Estes has 30 years of experience in the oil and gas industry with over 20 of those years directly involved in marketing in all regions of the country.

Joe D. Ford, age 63, became our Vice President of Human Resources in November 2007. Prior to joining EXCO Resources, Mr. Ford was the Director of Human Resources for CARBO Ceramics Inc. from June 2002 to November 2007. CARBO Ceramics Inc. supplies ceramic proppant for fracturing natural gas and oil wells and also provides well fracture diagnostic services. Prior to working for CARBO Ceramics Inc., Mr. Ford spent his career in various human resource management capacities including a subsidiary of General Dynamics as Manager of Human Resources and Comdial Corporation as Vice President of Human Resources.

Russell D. Griffin, age 47, joined EXCO in January 2008 and became our Vice President of Environmental, Health and Safety in June 2010. Mr. Griffin was previously our Director of Environmental, Health and Safety and Vice President of Health Safety Security and Environment for TGGT Holdings. Prior to joining EXCO, Mr. Griffin was the Senior Regulatory Representative for Hunt Oil Company, an independent international oil and natural gas exploration and production company, from August 2005 until January 2008. Mr. Griffin joined Hunt Oil Company in August of 1984 and held numerous positions in their Gulf Coast exploration and production operations until August 2005.

Richard L. Hodges, age 59, became our Vice President of Land 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 its properties in September 2000.

John D. Jacobi, age 57, became our Vice President of Business Development and Marketing 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.

Harold Jameson, age 43, became a Vice President in March 2011 and also serves as the General Manager of our East Texas/North Louisiana Joint Venture area. His primary focus is on the development of our Haynesville/Bossier Shale assets. Prior to the Haynesville Shale project, Mr. Jameson served as General Manager of our Vernon Field. Prior to joining EXCO in April 2007, he was employed at Anadarko Petroleum Corporation from 1991 to 2007 where he gained valuable experience in a variety of operating areas including U.S. onshore, offshore and international businesses in both development and exploration roles. Since 2001, Mr. Jameson has been responsible for Asset Management, Production Engineering, Reservoir Engineering and Field Development in the Central Texas, East Texas and North Louisiana operating areas. Mr. Jameson has a B.S. degree in Petroleum Engineering from Texas Tech University and is a member of the Society of Petroleum Engineers.

Tommy Knowles, age 60, joined EXCO's Appalachian subsidiary, North Coast Energy, Inc., in 2004 as its Vice President of Exploration & Production, becoming President in October 2005. In August 2007, Mr. Knowles became Vice President and General Manager of our Permian/Rockies Division. Prior to joining North Coast he was the Sr. Vice President of Exploration & Production with Belden and Blake, having been employed there since 1996.

Stephen E. Puckett, age 52, 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.

J. Douglas Ramsey, Ph.D., age 50, became our Vice President—Finance and Special Assistant to the Chairman on June 30, 2009 and became our Treasurer in October 2005. From December 1997 until June 30, 2009, Dr. Ramsey served as our Chief Financial Officer. 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 various universities including Southern Methodist University in their undergraduate and professional MBA programs.

Paul B. Rudnicki, age 33, became our Vice President of Financial Planning and Analysis in August 2006. From July 2003 until August 2006, Mr. Rudnicki served as Financial Planning Manager. Mr. Rudnicki was a Financial Analyst and Assistant to the CFO from June 2000 to July 2003.

Marcia Reeves Simpson, age 54, joined EXCO in March 2008 as our Vice President of Engineering. Ms. Simpson was employed by J-W Operating Company—Cohort Energy as its Acquisition & Divestiture and Reservoir Engineering Manager from September 2004 until March 2008. From January 2001 until September 2004, Ms. Simpson was a Vice President for Energy Virtual Partners, a start-up exploration and production company. From September 1987 until January 2000, she worked for Mobil Oil Corporation in various leadership positions including U.S. Technology Leader. From June 1978 to September 1987, she worked in several engineering positions for Gulf Oil Corporation/Chevron Corporation. She is a registered professional engineer in Louisiana and she has served in various leadership roles with the Gas Research Institute, the Society of Petroleum Engineers and the Society of Women Engineers over her 30 year career.

Andrew C. Springer, age 49, became our Vice President of Tax in November 2008. From May 2006 until November 2008, Mr. Springer served as our Director of Tax. Mr. Springer began his career in public accounting in 1987 at Arthur Andersen LLP and was named partner in 2001 specializing in mergers and acquisitions. He joined KPMG as a partner in 2002 and served in that role until he left in 2004 to become the Corporate Tax Officer for Tuesday Morning Corporation.

Robert L. Thomas, age 51, became our Chief Information Officer in May 2008. Prior to joining EXCO Resources, Mr. Thomas was the Director of Strategy and Architecture in Global Information Services at ConocoPhillips. Prior to working for ConocoPhillips, Mr. Thomas served Burlington Resources in the US, Canada and UK from 1994 to 2006 in various IT management capacities. Prior to Burlington Resources, Mr. Thomas worked for Oryx Energy Company. He began his career in the seismic data processing center at Sun Oil Company in 1981, and is an active member of the Society of Exploration Geophysicists.

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 SEC. Our officers, directors and 10% shareholders are required by SEC regulations 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 that two directors, Jeffrey D. Benjamin and Robert L. Stillwell, each reported 4 transactions with respect to fiscal 2010 and 2 transactions with respect to fiscal 2009 on a late Form 4. Each of the transactions reported in the late Form 4 filings were attributable to additional shares reserved by the Company for the benefit of such directors on a deferred basis following our 2009 and 2010 quarterly cash dividend payments pursuant to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc., or the Director Plan.

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 seeks to ensure 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 Annual Report on Form 10-K, the individuals who served as our chief executive officer and chief financial officer during fiscal 2010, 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.

When establishing total compensation for our 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.

From the time our current management team obtained control of EXCO in December 1997 through the end of 2008, our compensation philosophy was to provide all our 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 to entry level, have aligned interests. Through the end of 2008, all newly hired employees were awarded stock options on the first business day of the month following such employee's hire date and after that only when stock option bonuses were approved by our compensation committee, which generally occurred annually in December. Consistent with our compensation philosophy, these stock option bonuses were granted to all employees, including Named Executive Officers, at the same ratable percentage of each employee's annual base salary.

Due to our significant growth in employee headcount, particularly in 2007 and 2008, we determined that it was no longer feasible to award stock option bonuses in December at the same ratable percentage for all employees based on each employee's annual base salary, nor was it feasible to continue awarding stock options to all newly hired employees. It became necessary for us to reexamine our compensation philosophy with respect to our option grant practices in light of current and projected equity award “burn rates” and the number of shares available under the Amended and Restated EXCO Resources, Inc. 2005 Long-Term Incentive Plan, or Incentive Plan. At the same time, we were mindful of the need to maintain an incentive structure that would continue to foster our growth and overall success, encourage employees to maximize shareholder value and help us retain valuable personnel. With these realities and goals in mind, effective in December 2008, we modified our compensation philosophy to provide all our employees with cash incentives and only selected employees with stock-based incentives. As a result, we limited the December 2008 and 2009 stock option bonus awards to approximately 150 selected employees within our organization, including Named Executive Officers. Consistent with our compensation philosophy, the stock option bonuses in 2008 and 2009 were granted at the same ratable percentage of each employee’s annual base salary for all selected employees, including Named Executive Officers. Our remaining employees, excluding the employees that received stock options, received additional cash bonuses pursuant to a cash bonus plan. These additional cash bonuses were paid at the same ratable percentage of each applicable employee’s annual base salary, are subject to vesting restrictions that are similar to those under our stock option agreements to foster employee retention and include a change of control multiplier for any unvested amounts to provide an upside incentive similar to stock options. In addition, effective January 1, 2009, awards of stock options to new hires are only made to new employees on a purely discretionary basis, if approved by our compensation committee or pursuant to its delegated authority, and not to all new employees.

Certain employees, including one of our Named Executive Officers, received additional stock option bonuses in December 2009 on a purely discretionary basis for their contributions during 2009 executing our Haynesville shale development program, completing our East Texas/North Louisiana joint ventures with BG Group plc (“BG Group”) and divesting various non-core oil and natural gas properties.

In 2010, in light of the limited number of shares available under the Incentive Plan, we reexamined our compensation philosophy with respect to our option grant practices and considered alternatives to our traditional option grant practices that would not compromise or risk retention of our skilled labor force. We continued to believe that our incentive structure should encourage employees to maximize shareholder value and help us retain valuable personnel through the use of stock options and our cash bonus plan. In addition, competition for highly skilled, technical employees in the oil and natural gas industry remains intense, particularly for individuals with experience analyzing and exploiting shale resources. As a result of this reexamination, we determined that the objectives of the December 2010 option grants would be (a) to place a heightened emphasis on rewarding and retaining certain highly skilled personnel, including our Named Executive Officers, and (b) to ensure that a sufficient number of shares would be available under the Incentive Plan for option grants through 2011 without any increase in our option pool. We determined that a tiered approach using a Black Scholes grant date valuation (as opposed to our prior practice of granting option bonuses at the same ratable percentage of each selected employee’s annual base salary) would best accomplish our objectives. Under this tiered approach, officers received stock options with a Black-Scholes valuation as of the date of grant equal to 100% of their base salary and other managers and selected employees received stock options with a Black-Scholes valuation as of the date of grant of either 25% or 50% of their base salary based on their level of responsibility and position within the organization. This tiered approach allowed us to reduce the aggregate number of stock options that we would have otherwise granted using our historical practices but expand the number of selected employees that received stock options from approximately 150 in 2009 to approximately 225 in 2010. Our remaining employees, excluding the employees that received stock options, received additional cash bonuses pursuant to a cash bonus plan.

Role of Executive Officers in Compensation Decisions

Our Board of Directors has 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. 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 and has the final authority to establish the compensation packages for our executive officers.

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. The compensation committee engaged an outside consulting firm, Meridian Compensation Partners, LLC ("Meridian"), in November 2009 and August 2010 to conduct an annual review of our total compensation program for our Named Executive Officers as well as for other key executives. Each outside 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. Our peer group in 2010 consisted of the following companies: Cabot Oil & Gas Corporation; Cimarex Energy Co.; Comstock Resources Inc.; Continental Resources Inc., Denbury Resources Inc.; Forest Oil Corporation; Mariner Energy, Inc.; Newfield Exploration Company; Penn Virginia Corporation; Petrohawk Energy Corporation; Pioneer Natural Resources Inc.; Plains Exploration & Production Company; Quicksilver Resources Inc.; Range Resources Corporation; St. Mary Land & Exploration Company; Ultra Petroleum Corporation; W&T Offshore, Inc.; and Whiting Petroleum Corporation. From 2009 to 2010, the only changes to our peer group were the removal of CNX Gas Corporation, Encore Acquisition Company and EQT Corporation.

We compete with many larger companies for top executive-level talent. Although our compensation committee does not identify specific target ranges for the compensation of each executive officer, the compensation committee has historically set cash compensation (defined as annual salary plus expected cash bonus) for our executive officers between the twenty-fifth and 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 for our executive officers is allocated to stock options as a result of our compensation philosophy described above. We believe stock options incentivize our executive officers and other employees to achieve our long-term goal of maximizing shareholder value because income from stock option compensation is realized by our personnel only as a result of the successful performance of our company over time. 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 the outside consultant to determine the appropriate level and mix of compensation.

In November 2010, the compensation committee determined that increases in total direct compensation in the form of additional year-end cash bonuses were appropriate for 2010 based on:

- market data from Meridian demonstrating that cash bonus and total direct compensation levels for most of our executive officers were at or below the twenty-fifth percentile of our peer group and cash bonus levels were below the twenty-fifth percentile of our peer group. Total direct compensation is the sum of an individual's annual salary, cash bonus and the value of the individual's equity awards granted during that year;

- the contributions in 2010 by our executive officers and other management personnel in connection with our Haynesville shale development program, our Appalachia joint venture with BG Group and our significant reduction in Company indebtedness; and
- the compensation committee's belief that it was important to make a strong statement to our executive officers and other management personnel and reward, motivate and retain those individuals while keeping compensation well within the compensation range of our peer group.

These additional awards resulted in 2010 total direct compensation for our executive officers falling within our historical range of between the twenty-fifth and the median percentile of compensation paid to similarly situated executives of the companies comprising the peer group.

Executive Compensation Components

For the fiscal years ended December 31, 2010, 2009 and 2008, 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 that our compensation committee deems relevant. Although our compensation committee does not identify specific target ranges for the base salary of each executive officer, the compensation committee has historically set base salary opportunities for a given position 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 consultant;
- internal review of the executive's compensation, both individually and relative to other officers;
- individual performance of the executive;
- performance of the executive's department or functional unit;
- our operational performance, with respect to our production, reserves, finding and operating costs, drilling results, risk management activities and asset acquisitions;
- our financial performance, with respect to our cash flow, net income, cost of capital, general and administrative costs and Common Stock price performance;
- our overall competitive position and outlook relative to our industry;
- level of responsibility; and
- leadership ability, demonstrated commitment to the organization, motivational skills, attitude and work ethic.

Executive salary levels are typically considered annually by our compensation committee. 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 decided not to make any changes for fiscal 2008 or 2009. The compensation committee approved increases in the annual base salaries for each Named Executive Officer during 2007 and believed that those base salary levels remained appropriate for 2008 and 2009 based on an analysis of our peer group and other market data that our compensation committee deemed relevant. In particular, the compensation committee's decision to retain the current base salary level for all Named Executive Officers in 2009 reflected a tone at the top philosophy of our organization's commitment to cash retention at a time when we were experiencing a global economic and industry downturn.

In November 2009, the compensation committee reviewed the annual base salaries for all our officers, including Named Executive Officers, and determined that effective January 1, 2010 raises averaging approximately 23% of such officers' base salaries were appropriate. The compensation committee's decision was based primarily on the contributions of our officers and other management personnel in 2009 in connection with our Haynesville shale development program, our joint ventures with BG Group, our divestitures of various non-core oil and natural gas properties and our significant reduction in Company indebtedness. The compensation committee believed that the accomplishment of these strategic objectives enhanced the long-term value and future prospects of the Company. The compensation committee also took into account that our Named Executive Officers had not received salary increases since April 2007. Effective January 1, 2010, our Named Executive Officers are paid the following annual base salaries:

- Douglas H. Miller—$1,000,000
- Stephen F. Smith—$750,000
- Harold L. Hickey—$450,000
- William L. Boeing—$500,000
- Mark E. Wilson—$350,000

In November 2010, the compensation committee reviewed the annual base salaries for our Named Executive Officers and decided not to make any changes for fiscal 2011. The compensation committee approved increases in the annual base salaries for each Named Executive Officer for fiscal 2010 and believed that those base salary levels remained appropriate for 2011 based on an analysis of our peer group and other market data that our compensation committee deemed relevant.

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 as determined by our Board of Directors. Until December 2009, all employees, from the most senior executives of our organization to entry level, received the same percentage level cash bonuses, pro-rated for any partial period of service, as those received by our Named Executive Officers. Exceptions were made from time to time to provide additional cash bonuses to certain employees who made extraordinary contributions to our success. In 2008 and 2007, 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 were not Named Executive Officers. In 2009 and 2010, we paid a cash bonus to each employee and each Named Executive Officer in an amount equal to 20% of their respective annual base salary. In addition, the compensation committee was presented with market data from Meridian in November 2009 and 2010 demonstrating that cash bonus levels for most of our executive officers was below the twenty-fifth percentile of our peer group. Based on this market data and the contributions in 2009 and 2010 by our executive officers and other management personnel in connection with our Haynesville shale development program, our joint ventures with BG Group, our divestitures of various non-core oil and natural gas properties and our significant reduction in Company indebtedness, the compensation committee determined that additional year-end cash bonuses were appropriate for 2009 and 2010. As a result, we paid additional cash bonuses averaging approximately 22% and 21% of base salary amounts in 2009 and 2010, respectively, to our executive officers and other management personnel who played significant roles in the accomplishment of those strategic objectives.

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 and not any particular financial, operational or individual performance criteria or target. Each of the Named Executive Officers received the following cash bonus payments in December 2010 for fiscal 2010 performance, in December 2009 for fiscal 2009 performance and in December 2008 for fiscal 2008 performance.

Name	2010 Cash Bonus	2009 Cash Bonus	2008 Cash Bonus
Douglas H. Miller	$400,000	$320,000	$160,000
Stephen F. Smith	$300,000	$240,000	$120,000
Harold L. Hickey	$190,000	$170,000	$ 70,000
William L. Boeing	$200,000	$160,000	$ 80,000
Mark E. Wilson	$140,000	$135,000	$ 55,000

Long-Term Incentive Compensation

Incentive Plan. In many cases, incentives granted under the Incentive Plan comprise the largest portion of our Named Executive Officers' total compensation package. This plan was originally adopted and approved by the Board of Directors of our predecessor entity in September 2005 and ultimately assumed by us. An amendment to this plan was approved by our shareholders in August 2007 increasing the number of shares of Common Stock authorized for issuance under the plan from 10,000,000 shares to 20,000,000 shares. Another amendment to this plan was approved by our shareholders in June 2009 increasing the number of shares of Common Stock authorized for issuance under the plan from 20,000,000 shares to 23,000,000 shares and requiring that each share granted that is subject to a full-value award will count as 1.17 shares against the total number of shares we have reserved for issuance under the 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 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 under this plan 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 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 enter 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. All 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.

Prior to January 1, 2009, all new employees were awarded stock options on the first business day of the month following such employee's hire date and after that only when stock option bonuses were approved by our compensation committee, which generally occurred annually in December. Effective January 1, 2009, awards of stock options to new hires are made on a purely discretionary basis, if approved by our compensation committee or pursuant to its delegated authority, and not to all new employees. In December 2009 and 2008, we granted stock option bonuses to selected employees, including all of the Named Executive Officers, such that each applicable employee received an option to purchase that number of shares equal to their annual base salary in 2009 and 2008 divided by $10. These grants were consistent with our prior compensation philosophy and historical grant rates for these individuals. Our formula at that time for determining stock option grant sizes took a percentage of base salary (historically 10%) and converted that portion of base salary into a number of stock options where $1 of the portion of base salary equals an option to purchase 1 share of stock. Based on this formula, we granted stock options to the Named Executive Officers in December 2009 as set forth in the table below.

Name	2009 Base Salary	2009 Grant Percentage	2009 Stock Options	Grant Date Fair Value
Douglas H. Miller	$800,000	10%	80,000	$790,104
Stephen F. Smith	$600,000	10%	60,000	$592,578
Harold L. Hickey	$350,000	10%	35,000	$345,671
William L. Boeing	$400,000	10%	40,000	$395,052
Mark E. Wilson.	$275,000	10%	27,500	$271,598

In addition, Mr. Wilson received an additional grant of 10,000 stock options in December 2009 on a purely discretionary basis for his contributions during 2009 completing our East Texas/North Louisiana joint ventures with BG Group and divesting various non-core oil and natural gas properties.

As described under "—Compensation Philosophy and Objectives" and in accordance with our modified compensation philosophy, we granted stock option bonuses in December 2010 to selected employees, including all of the Named Executive Officers, using a Black Scholes grant date valuation ranging from 25% to 100% of such employee's annual base salary in effect during that year, pro rata for any partial year of service. Based on this formula, we granted stock options to the Named Executive Officers in December 2010 as set forth in the table below.

Name	2010 Base Salary	Grant Date Fair Value	2010 Stock Options
Douglas H. Miller	$1,000,000	$1,000,619	97,400
Stephen F. Smith	$ 750,000	$ 749,951	73,000
Harold L. Hickey	$ 450,000	$ 449,971	43,800
William L. Boeing	$ 500,000	$ 500,310	48,700
Mark E. Wilson.	$ 350,000	$ 350,320	34,100

While the grant date fair values of the 2010 stock option grants for each Named Executive Officer increased as compared to 2009, the award levels continue to be significantly below the 50th percentile of our peer group. The compensation committee evaluated using time-based restricted stock grants for a portion of the 2010 awards, but determined that the use of stock options created a better alignment between management and shareholder interests.

Our remaining employees who did not receive stock option bonuses received additional cash bonuses pursuant to our cash bonus plan equal to 10% of their annual base salary in December 2010, 2009 and 2008 (excluding bonuses and overtime), with 25% of such bonuses paid immediately and the remainder to be paid in three annual installments so long as they remain an employee.

The following table shows the number of EXCO employees as of December 31, 2010, 2009, 2008, 2007 and 2006, the number of stock options granted to new hires and the number of stock options granted as a year-end bonus during each of the five years ended December 31, 2010.

	2010	2009	2008	2007	2006
Number of EXCO Employees	927	802	892	689	471
Option Awards to New Hires	443,700	424,750	1,790,800	1,948,500	1,444,200
Annual December Option Bonus Awards	1,744,200	2,543,800	2,288,200	3,000,200	2,171,500

The exercise prices, the number of shares subject to each grant, and other information about the stock options granted to our Named Executive Officers during fiscal year 2010 are shown in the "2010 Fiscal Year Grants of Plan-Based Awards" table contained in "Compensation of Executive Officers." 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.

Stock Ownership Guidelines. We do not have formal stock ownership guidelines. However, our executive officers are encouraged to maintain or establish a significant level of direct stock ownership.

Retirement and Other Benefit Plans

401(k) Plan. All of our employees are eligible to participate in the EXCO Resources, Inc. 401(k) Plan. We match 100% of employee contributions to the 401(k) plan with vesting of Company matching contributions based on years of service with us. In addition, our employees may select our Common Stock as an investment option under the 401(k) plan, up to a maximum of 50% of their contribution.

Severance Plan. The Fourth 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 1.25 times an employee's annual 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 twelve months following a change of control, as defined in the Severance Plan. For more information about the Severance Plan, see "—Compensation of Executive Officers—Potential Payments Upon Termination or Change-in-Control."

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 provided two of our Named Executive Officers in 2010 and one of our Named Executive Officers in 2009 and 2008 with perquisites and other personal benefits that the compensation committee believed were reasonable and consistent with our overall compensation program. Mr. Ramsey spent approximately 20% of his time on Mr. Douglas H. Miller's personal business ventures during 2010. In addition, Mr. Miller's administrative assistants spent between approximately 5% and 20% of their time on Mr. Miller's personal matters during 2010 and one of his administrative assistants spent approximately 5% of her time on Mr. Miller's personal matters in 2009 and 2008. Mr. Smith's administrative assistant spent approximately 10% of her time on Mr. Smith's personal matters during 2010. On limited occasions, executives authorized to use chartered aircraft for business travel may, if space allows, bring family members or guests along on the trip provided they have the prior approval of certain members of our senior management. 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, if any, of the personal benefits described above for the Named Executive Officers for the fiscal years ended December 31, 2010, 2009 and 2008 are included in the Summary Compensation Table under the heading "All Other Compensation."

Compensation for our Chief Executive Officer

As our chairman, chief executive officer and founder, Mr. Miller is the key visionary for our organization. He has helped us achieve substantial growth in annual revenues, production and reserves over the past 13 years. As a significant shareholder, Mr. Miller has a major portion of his personal wealth tied directly to the performance of our stock price, providing direct alignment with shareholder interests. Like many of our industry peers, EXCO faced significant challenges during the last half of 2008 and through 2009 in connection with the global financial and credit crisis and the associated decline in oil and natural gas prices. In addition, EXCO carried a substantial amount of indebtedness, some of which had near-term maturities, at a time when funding sources were limited. Despite these challenges, Mr. Miller was instrumental in securing additional funding sources to refinance our near-term indebtedness. During 2009 and 2010, his strategic vision set in motion our joint ventures with BG Group in East Texas and North Louisiana and Appalachia and our divestiture program that included various non-core oil and natural gas properties, all of which allowed EXCO to significantly reduce its indebtedness and generate available cash at a time when many of our competitors struggled to generate capital. He also helped transform EXCO from an acquisition-oriented company into a significant shale participant in 2009 and 2010. The compensation committee believes that Mr. Miller has positioned us for substantial growth in reserve potential, production and cash flow as a significant participant in two of the dominant shale plays in the United States, namely the Haynesville/Bossier shale in East Texas and North Louisiana and the Marcellus shale in Appalachia.

When compared to compensation levels of chief executive officers for our peer companies, Meridian's survey concluded that Mr. Miller's total direct compensation in 2010 ranked below the twenty-fifth percentile of his peers.

Based on Meridian's survey and the extraordinary contributions in 2010 by Mr. Miller in connection with our Haynesville shale development program, our joint ventures with BG Group and our significant reduction in Company indebtedness, the compensation committee determined that Mr. Miller should receive an additional cash bonus in 2010. Mr. Miller's additional cash bonus was the same on a percentage basis as our other executive officers and management personnel who played significant roles in the accomplishment of our strategic objectives during 2010. As a result, Mr. Miller received the historical 20% of base pay cash bonus plus an additional 20% of base pay cash bonus for a total cash bonus equal to $400,000. In addition, the compensation committee determined not to change Mr. Miller's base salary level for 2011 based on an analysis of our peer group and other market data that our compensation committee deemed relevant.

Internal Pay Equity

While comparisons to compensation levels at companies in our peer group are helpful in assessing the competitiveness of our compensation program, we believe that our executive compensation program also should generally be internally equitable taking into account various levels of authority and responsibility of our employees in order to achieve our compensation objectives. When setting executive compensation each year, we informally analyze the relationship between our chief executive officer's total compensation and the total compensation of our president and our Named Executive Officers. For this purpose, total compensation includes base salary, bonus payments and the value of equity awards calculated in the manner described in the Summary Compensation Table below. In addition, we consider the internal pay equity between the Named Executive Officers and our other officers and divisional managers. The following table illustrates the internal pay equity ratios among our chief executive officer, our president, our Named Executive Officers and our other officers and divisional managers as of December 31, 2010, 2009 and 2008.

	2010	2009	2008
CEO/President	1.3x	1.3x	1.3x
CEO/Other Named Executive Officers	1.9x	1.9x	2.0x
CEO/Other Officers and Divisional Managers	3.3x	3.0x	3.1x
Named Executive Officers/Other Officers and Divisional Managers	2.0x	1.8x	1.8x

Compensation Business Risk Review

Although portions of our salary and bonus compensation structure are performance-based, we compensate our executive officers and other employees with a salary and bonus structure that is focused on overall company performance and is not based on the achievement of any targets or milestones by any individual department or function. In addition, our executive officers and other employees have a significant ownership stake in the Company resulting from direct investments and our long-term incentive compensation program. Historically, the only long-term incentive compensation that we have granted to our executive officers or other employees is in the form of stock options because we believe stock options incentivize our executive officers and other employees to achieve our long-term goal of maximizing shareholder value. Income from stock option compensation is realized only as a result of the successful performance of our Company over time. Finally, the other elements of our compensation are comprised of typical benefit plans, such as a 401(k) Plan and health, life and disability insurance. Accordingly, our compensation committee believes that our compensation policies and practices do not create unreasonable or inappropriate risks that are reasonably likely to have a material adverse effect on the Company.

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 generally that we may not deduct compensation of more than $1,000,000 that is paid to certain individuals. Other than with respect to Mr. Miller, 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. We believe that we are operating in compliance with the final regulations that became effective January 1, 2009.

Accounting for Stock-Based Compensation

Our predecessor adopted the provisions of Financial Accounting Standards Board, or FASB, Accounting Standards Codification, or ASC, Topic 718—Compensation—Stock Compensation, or ASC 718, upon its formation in August 2005. Upon the closing of a series of mergers in connection with our initial public offering in February 2006, we adopted ASC 718.

Compensation Committee Report

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 Annual Report on Form 10-K.

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

COMPENSATION COMMITTEE
Robert L. Stillwell, Chairman
Jeffrey D. Benjamin
Vincent J. Cebula
Earl E. Ellis
B. James Ford*
Mark Mulhern**
Jeffrey S. Serota

* Mr. Ford was appointed to the compensation committee on March 13, 2008 and therefore did not participate in setting executive compensation for fiscal 2008.

** Mr. Mulhern was appointed to the compensation committee on February 22, 2010 and therefore did not participate in setting executive compensation for fiscal 2008 or 2009.

Compensation of Executive Officers

The total compensation paid to our chief executive officer, Mr. Douglas H. Miller, our president and chief financial officer, Mr. Stephen F. Smith, 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, 2010, 2009 and 2008 is set forth in the following Summary Compensation Table:

2010, 2009 AND 2008 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 . . .	2010	1,000,000	400,000	—	1,000,619	—	—	22,000	2,422,619
Chairman and	2009	800,000	320,000	—	790,104	—	—	22,000	1,932,104
Chief Executive Officer	2008	800,000	160,000	—	382,464	—	—	20,500	1,362,964
Stephen F. Smith	2010	750,000	300,000	—	749,951	—	—	22,000	1,821,951
Vice Chairman,	2009	600,000	240,000	—	592,578	—	—	22,000	1,454,578
President and Chief Financial Officer	2008	600,000	120,000	—	286,848	—	—	20,500	1,027,348
Harold L. Hickey . . .	2010	450,000	190,000	—	449,971	—	—	22,000	1,111,971
Vice President and	2009	350,000	170,000	—	345,671	—	—	22,000	887,671
Chief Operating Officer	2008	350,000	70,000	—	167,328	—	—	20,500	607,828
William L. Boeing . .	2010	500,000	200,000	—	500,310	—	—	22,000	1,222,310
Vice President,	2009	400,000	160,000	—	395,052	—	—	22,000	977,052
General Counsel and Secretary	2008	400,000	80,000	—	191,232	—	—	20,500	691,732
Mark E. Wilson	2010	350,000	140,000	—	350,320	—	—	22,000	862,320
Vice President,	2009	275,000	135,000	—	370,361	—	—	22,000	802,361
Chief Accounting Officer and Controller	2008	268,750	55,000	—	131,472	—	—	15,500	470,722

(1) This column represents the aggregate grant date fair value of stock options granted to each Named Executive Officer in 2010, 2009 and 2008 in accordance with ASC 718, with the exception that the amount shown assumes no forfeitures. Assumptions used in the calculation of these amounts are included in "Note 2. Summary of significant accounting policies—Stock options" and "Note 12. Stock options" to our audited financial statements for the fiscal year ended December 31, 2010 included in our Annual Report on Form 10-K filed with the SEC on February 24, 2011.

(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. 401(k) Plan as follows: Mr. Miller—$22,000; Mr. Smith—$22,000; Mr. Hickey—$22,000; Mr. Boeing—$22,000; and Mr. Wilson—$22,000 for 2010; Mr. Miller—$22,000; Mr. Smith—$22,000; Mr. Hickey—$22,000; Mr. Boeing—$22,000; and Mr. Wilson—$22,000 for 2009; Mr. Miller—$20,500; Mr. Smith—$20,500; Mr. Hickey—$20,500; Mr. Boeing—$20,500; and Mr. Wilson—$15,500 for 2008. We maintain a suite at the American Airlines Center in Dallas, Texas and a suite 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 of an estimated 20% of Mr. Ramsey's time on Mr. Miller's personal business ventures,

Mr. Miller's use of an estimated 5% to 20% of administrative assistants' time for personal matters or Mr. Smith's use of an estimated 10% of his administrative assistant's time for personal matters. The aggregate incremental cost to the Company for the use of Mr. Ramsey's and the assistants' time is valued at $0.00 because the Company did not incur any additional expenses for such employees as a result of such use.

(3) Mr. Miller owns two aircraft through DHM Aviation, LLC. During 2010, 2009 and 2008, 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 in line with the market rate for the charter of similar aircraft. On limited occasions, executives authorized to use a chartered aircraft for business travel may, if space allows, bring family members or guests along on the trip provided they have the prior approval of certain members of our senior management. 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.

See "—Compensation Discussion and Analysis—Executive Compensation Components—Base Salary" for a discussion of the 2011 base salaries of our Named Executive Officers.

Equity Incentive Awards

The following table sets forth information regarding the plan-based awards under the Incentive Plan granted to each Named Executive Officer during the fiscal year ended December 31, 2010:

2010 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
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)	(#)	(#)	($ / Share)	($)(1)
Douglas H. Miller	12/7/2010	—	—	—	—	—	—	—	97,400(2)	$18.50	$1,000,619
Stephen F. Smith	12/7/2010	—	—	—	—	—	—	—	73,000(2)	$18.50	$ 749,951
Harold L. Hickey	12/7/2010	—	—	—	—	—	—	—	43,800(2)	$18.50	$ 449,971
William L. Boeing	12/7/2010	—	—	—	—	—	—	—	48,700(2)	$18.50	$ 500,310
Mark E. Wilson	12/7/2010	—	—	—	—	—	—	—	34,100(2)	$18.50	$ 350,320

(1) Represents the grant date fair value of the awards computed in accordance with ASC 718, with the exception that the amount shown assumes no forfeitures. Assumptions used in the calculation of these amounts are included in "Note 2. Summary of significant accounting policies—Stock options" and "Note 12. Stock options" to our audited financial statements for the fiscal year ended December 31, 2010 included in our Form 10-K filed with the SEC on February 24, 2011.

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

The following table sets forth information regarding the outstanding equity awards held by our Named Executive Officers as of December 31, 2010:

2010 FISCAL YEAR OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

		Option Awards(1)					Stock Awards			
Name	**Grant Date**	**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 . .	10/5/2005	1,705,000	—	—	$ 7.50	10/4/2015	—	—	—	—
	12/1/2006	60,000	—	—	$14.62	11/30/2016	—	—	—	—
	12/4/2007	80,000	—	—	$13.72	12/3/2017	—	—	—	—
	12/11/2008	60,000	20,000	—	$ 7.88	12/10/2018	—	—	—	—
	12/1/2009	40,000	40,000	—	$17.60	11/30/2019	—	—	—	—
	12/7/2010	24,350	73,050	—	$18.50	12/6/2020	—	—	—	—
Stephen F. Smith . . .	10/5/2005	383,300	—	—	$ 7.50	10/4/2015	—	—	—	—
	12/1/2006	40,000	—	—	$14.62	11/30/2016	—	—	—	—
	12/4/2007	60,000	—	—	$13.72	12/3/2017	—	—	—	—
	12/11/2008	45,000	15,000	—	$ 7.88	12/10/2018	—	—	—	—
	12/1/2009	30,000	30,000	—	$17.60	11/30/2019	—	—	—	—
	12/7/2010	18,250	54,750	—	$18.50	12/6/2020	—	—	—	—
Harold L. Hickey . . .	10/5/2005	166,700	—	—	$ 7.50	10/4/2015	—	—	—	—
	12/1/2006	30,000	—	—	$14.62	11/30/2016	—	—	—	—
	12/4/2007	35,000	—	—	$13.72	12/3/2017	—	—	—	—
	12/11/2008	26,250	8,750	—	$ 7.88	12/10/2018	—	—	—	—
	12/1/2009	17,500	17,500	—	$17.60	11/30/2019	—	—	—	—
	12/7/2010	10,950	32,850	—	$18.50	12/6/2020	—	—	—	—
William L. Boeing . .	4/5/2006	500,000	—	—	$12.36	4/4/2016	—	—	—	—
	12/1/2006	26,200	—	—	$14.62	11/30/2016	—	—	—	—
	12/4/2007	40,000	—	—	$13.72	12/3/2017	—	—	—	—
	12/11/2008	30,000	10,000	—	$ 7.88	12/10/2018	—	—	—	—
	12/1/2009	20,000	20,000	—	$17.60	11/30/2019	—	—	—	—
	12/7/2010	12,175	36,525	—	$18.50	12/6/2020	—	—	—	—
Mark E. Wilson	10/5/2005	30,000	—	—	$ 7.50	10/4/2015	—	—	—	—
	12/1/2006	25,000	—	—	$14.62	11/30/2016	—	—	—	—
	12/4/2007	25,000	—	—	$13.72	12/3/2017	—	—	—	—
	12/11/2008	20,625	6,875	—	$ 7.88	12/10/2018	—	—	—	—
	12/1/2009	18,750	18,750	—	$17.60	11/30/2019	—	—	—	—
	12/7/2010	8,525	25,575	—	$18.50	12/6/2020	—	—	—	—

(1) Pursuant to the terms of the stock option agreements that we entered into with our option holders, these options are vested as to 25% of the shares subject to the option on the date of grant and vest an additional 25% on each of the next three anniversaries of the date of grant provided that the holder of the option remains employed with us on that date. These options 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.

Option Exercises And Stock Vested During 2010

None of our Named Executive Officers exercised any stock options or held any unvested stock during 2010. As a result, we have not included a table showing option exercises or stock vested during 2010.

Pension Benefits

We do not provide any pension benefits for our Named Executive Officers.

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 of Control

Third Amended and Restated EXCO Resources, Inc. Severance Plan

Set forth below is a description of our Third Amended and Restated EXCO Resources, Inc. Severance Plan, which we refer to as the "Prior Severance Plan" and was in effect as of December 31, 2010. The Prior Severance Plan was amended and restated on March 16, 2011, and a description of the material changes effected by such amendment and restatement is set forth below under the caption "—Fourth Amended and Restated EXCO Resources, Inc. Severance Plan."

The Prior Severance Plan provided for the payment of severance in the event the employee's employment was terminated or there was an adverse change in the employee's job or compensation, as more specifically described in the Prior Severance Plan, within six months following a change of control of EXCO. The Prior Severance Plan was, and the Severance 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 were eligible to participate in and receive benefits under the Prior Severance Plan and currently are eligible to participate in and receive benefits under the Severance Plan.

A change of control is defined under the Prior Severance Plan and the Severance Plan 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 or other nominees that are appointed or otherwise approved by the Board of Directors then still in office, 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 was equal to one year of an employee's base salary to be paid in cash in a lump sum within ten days following receipt by us of an executed release form.

The following tables show, as of December 31, 2010, 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 $19.42 (as reported on the NYSE as of December 31, 2010). 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)	$ —	$1,000,000	$ —	$ —	$ —
Long-term Equity Incentives— Unvested Stock Options(3)	370,806	370,806	370,806	370,806	370,806
Total	$370,806	$1,370,806	$370,806	$370,806	$370,806

Stephen F. Smith
Vice Chairman, President and Chief Financial 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)	$ —	$ 750,000	$ —	$ —	$ —
Long-term Equity Incentives— Unvested Stock Options(3)	278,070	278,070	278,070	278,070	278,070
Total	$278,070	$1,028,070	$278,070	$278,070	$278,070

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)	$ —	$450,000	$ —	$ —	$ —
Long-term Equity Incentives— Unvested Stock Options(3)	163,047	163,047	163,047	163,047	163,047
Total	$163,047	$613,047	$163,047	$163,047	$163,047

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)	$ —	$500,000	$ —	$ —	$ —
Long-term Equity Incentives— Unvested Stock Options(3)	185,403	185,403	185,403	185,403	185,403
Total	$185,403	$685,403	$185,403	$185,403	$185,403

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

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— Unvested Stock Options(3)	136,992	136,992	136,992	136,992	136,992
Total	$136,992	$486,992	$136,992	$136,992	$136,992

(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) Represents a payment equal to 100% of the officer's annual base salary. Such amount is calculated under our Third Amended and Restated EXCO Resources, Inc. Severance Plan, which was adopted on November 14, 2007 and in effect on December 31, 2010. For a description of severance payments that may be due pursuant to the Fourth Amended and Restated EXCO Resources, Inc. Severance Plan, see "—Fourth Amended and Restated EXCO Resources, Inc. Severance Plan."

(3) Excludes stock options that are currently exercisable. 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.

Fourth Amended and Restated EXCO Resources, Inc. Severance Plan

On March 16, 2011, the Compensation Committee of the Board of Directors adopted the Fourth Amended and Restated EXCO Resources, Inc. Severance Plan, which amended, restated and replaced the Prior Severance Plan. Among other things, the Fourth Amended and Restated EXCO Resources, Inc. Severance Plan amended the Prior Severance Plan to: (i) increase the amount of severance pay for eligible employees from one times their base pay to 1.25 times their base pay, (ii) extend the protection period following a change of control for eligible employees from six months to twelve months, and (iii) limit the circumstances in which an eligible employee can terminate for "good reason" to a material reduction in base pay or a forced relocation. In addition, as amended, the Severance Plan now provides that eligible employees will receive their severance payments in cash in a lump sum 60 days following termination of employment, provided that we have timely received an executed release form, instead of 10 days after receipt of an executed release form.

Pursuant to the Fourth Amended and Restated EXCO Resources, Inc. Severance Plan, as of April 15, 2011, our Named Executive Officers would be entitled to the following amounts of severance pay if they were terminated other than for cause or misconduct within twelve months after a change of control:

Name	Termination Not for Cause or Misconduct Within Twelve Months After a Change of Control
Douglas H. Miller	$1,250,000
Stephen F. Smith	937,500
Harold L. Hickey	562,500
William L. Boeing	625,000
Mark E. Wilson	437,500

Director Compensation

The following table provides compensation information for the one year period ended December 31, 2010 for each non-employee member of our Board of Directors:

2010 FISCAL YEAR DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)	Option Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Jeffrey D. Benjamin	$100,000	—	$ 49,935	—	—	—	$149,935
Vincent J. Cebula(3)	$230,000	—	$ 49,935	—	—	—	$279,935
Earl E. Ellis	$ 45,000	—	$ 49,935	—	—	—	$ 94,935
B. James Ford	$ 50,000	—	$ 49,935	—	—	—	$ 99,935
Mark Mulhern(3)(4)	$225,000	—	$730,160	—	—	—	$955,160
T. Boone Pickens	$ 40,000	—	$ 49,935	—	—	—	$ 89,935
Jeffrey S. Serota	$ 55,000	—	$ 49,935	—	—	—	$104,935
Robert L. Stillwell	$ 55,000	—	$ 49,935	—	—	—	$104,935

(1) Includes the amount of cash fees forgone at the election of Messrs. Benjamin, Ellis and Mulhern and either paid during 2010 or deferred until a later date in shares of our Common Stock pursuant to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc. See "—Director Plan."

(2) This column represents the aggregate grant date fair value of stock options granted to each non-employee director in 2010 in accordance with ASC 718, with the exception that the amount shown assumes no forfeitures. Assumptions used in the calculation of these amounts are included in "Note 2. Summary of significant accounting policies—Stock options" and "Note 12. Stock options" to our audited financial statements for the fiscal year ended December 31, 2010 included in the Form 10-K filed with the SEC on February 24, 2011. Pursuant to the policies of Oaktree, Mr. Ford has assigned all economic and pecuniary interest and voting rights with respect to his director fees, including stock option awards, to the Oaktree Funds. Pursuant to the policies of Ares, Mr. Serota has assigned all economic and pecuniary interests and voting rights with respect to his director fees, including stock option awards, to Ares.

(3) Includes $175,000 paid in cash in connection with service on the special committee of the Board of Directors.

(4) Mr. Mulhern was granted an option to purchase 65,000 shares of our Common Stock on February 1, 2010 in connection with his appointment to the Board of Directors.

Cash Compensation. Our non-employee directors were paid an annual retainer of $40,000 in 2010. The chair of our compensation committee and nominating and corporate governance committee were paid an additional $10,000 in 2010 and the chair of the audit committee was paid an additional $50,000. Each non-chair member of our compensation committee, nominating and corporate governance committee and audit committee was paid an additional $5,000 in 2010. The members of the special committee were paid a flat fee of $175,000 in 2010. 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.

In May 2009, the compensation committee engaged Hewitt Consulting, now known as Meridian to conduct a competitive market analysis of our outside director compensation program. Meridian's survey included market data from the same peer group of publicly-traded oil and natural gas companies described under the heading "Compensation Discussion and Analysis—Setting Executive Compensation." Meridian's survey concluded that the total compensation paid to each outside director was below the twenty-fifth percentile of our peer group, particularly as a result of the $25,000 annual retainer falling significantly below the twenty-fifth percentile of our peer group. The fees paid to our outside directors have not been changed since before our initial public offering in February 2006. Based on Meridian's survey and the overall performance of the Company in 2009, effective January 1, 2010, the Board of Directors raised the annual retainer from $25,000 to $40,000. The other fees paid for chairman and committee service were not changed. In November 2010, the Board of Directors determined not to make any changes to director compensation for fiscal 2011.

Option Grant. On November 5, 2010, each of our non-employee directors received an automatic annual grant under the Director Plan (as described below) of an option to purchase 5,000 shares. The exercise price per share of each option was set at the closing price of our Common Stock on the NYSE on November 5, 2010. The option has a term of ten years, with 25% of the shares subject to the option (1,250 shares) vesting immediately and the balance vesting in equal proportions on the next three anniversary dates. The unvested shares subject to the option will be forfeited if a director ceases to serve on the Board of Directors for any reason. In addition, no shares granted under the Director Plan will vest, and the shares that would otherwise have vested will be forfeited, in any fiscal year in which a director attends less than 75% of the Board of Directors meetings held for that fiscal year. However, this option will be subject to acceleration upon a change of control as defined under the Incentive Plan.

Director Plan. The Director 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 received his fees for service during 2010 in cash. Messrs. Cebula, Ford, Serota and Stillwell received cash for their service during 2010. Messrs. Benjamin and Ellis elected to receive their fees for service during 2010 entirely in our Common Stock. Mr. Mulhern elected to receive his director fees 50% in cash and 50% in our Common Stock during 2010. None of our directors elected to change the manner in which they will receive director fees in 2011. All director fees are paid on a quarterly basis. 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 our Common Stock on the NYSE on that date.

The Director 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). 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. Only Mr. Benjamin elected to defer the payment of his 2010 and 2011 director fees under the Director Plan.

The Director Plan was amended in November 2009 to (i) eliminate automatic stock option grants to new directors and (ii) provide for an automatic annual stock option grant to each of our directors to purchase 5,000 shares of our Common Stock beginning December 1, 2009 and each year thereafter on the third business day following the release of our third quarter earnings. The exercise price will be set at the closing price of our Common Stock on the NYSE on the date of grant. The option will have a term of ten years, with 25% of the shares subject to the option vesting immediately and the balance vesting in equal proportions on the next three anniversary dates. No shares granted under the Director Plan will vest, and the shares that would otherwise have vested will be forfeited, in any fiscal year in which a 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 will be forfeited. However, this option will be subject to acceleration upon a change of control as defined under the Incentive Plan. All shares issuable under the Director Plan, including pursuant to any option granted thereunder, will be deemed issued under the terms of the Incentive Plan.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended December 31, 2010, the compensation committee was comprised of Messrs. Stillwell (chair), Benjamin, Cebula, Ellis, Ford, Mulhern and Serota.

During the fiscal year ended December 31, 2010, 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. 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, 2010 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	16,478,926	$ 13.68	2,068,375
Equity compensation plans not approved by security holders	Not applicable	Not applicable	Not applicable
Total	16,478,926	$ 13.68	2,068,375

Security Ownership Of Certain Beneficial Owners And Management

The following tables set forth as of April 15, 2011 the number and percentage of shares of our Common Stock beneficially owned by (i) each person known by us to beneficially own more than 5% of the outstanding shares of our Common Stock and (ii) 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 of Common Stock beneficially owned by a person and the beneficial ownership percentage 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 15, 2011 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 213,780,898 shares of Common Stock outstanding as of April 15, 2011. 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.

Principal Shareholders

	Common Stock Beneficial Ownership	
Beneficial owner	**Shares**	**% of Class**
Holders of more than 5%		
T. Boone Pickens, Jr.(1) 8117 Preston Road Suite 260W Dallas, TX 75225	10,677,850	5.0%
Oaktree Capital Group Holdings GP, LLC(2) 333 S. Grand Avenue, 28th Floor Los Angeles, CA 90071	34,850,196	16.3%
FMR LLC(3) 82 Devonshire Street Boston, MA 02109	11,269,897	5.3%
Ares Management LLC(4) 1999 Avenue of the Stars Suite 1900 Los Angeles, CA 90067	12,951,537	6.1%
WL Ross & Co. LLC(5) 1166 Avenue of the Americas New York, New York 10036	21,000,000	9.8%

(1) Includes 58,750 shares of our Common Stock subject to stock options that are exercisable within 60 days of April 15, 2011. Includes 10,619,100 shares of Common Stock held in an account with a bank and pledged as collateral security for the repayment of debit balances, if any, in such account.

(2) Includes shares of our Common Stock held by OCM Principal Opportunities Fund III, L.P. ("Fund III"), OCM Principal Opportunities Fund IIIA, L.P. ("Fund IIIA"), OCM Principal Opportunities Fund IV Delaware, L.P. ("Fund IV Delaware") and OCM EXCO Holdings, LLC ("OCM EXCO", and together with Fund III, Fund IIIA and Fund IV Delaware, the "Funds"). Oaktree Capital Group Holdings GP, LLC ("Oaktree Group") ultimately controls Fund III, Fund IIIA, Fund IV and OCM EXCO.

Oaktree Fund GP I, L.P. ("GP I") is the general partner of OCM Principal Opportunities Fund III GP, L.P. ("Fund III GP"), the general partner of Fund III and Fund IIIA. By virtue of their relationship to Fund III and Fund IIIA, (a) Fund III GP and (b) GP I may be deemed to have beneficial ownership of the shares owned by Fund III and Fund IIIA. Stephen Kaplan and Ronald Beck are a Principal and a managing director, respectively, of Oaktree Capital Management, L.P. ("Oaktree"), the investment manager of

Fund III and Fund IIIA, and are the portfolio managers for Fund III and Fund IIIA. Mr. Kaplan, Mr. Beck, Fund III GP and GP I disclaim beneficial ownership of the securities held by Fund III and Fund IIIA, except to the extent of any pecuniary interest therein.

OCM Principal Opportunities Fund IV, L.P. ("Fund IV") is the sole shareholder of OCM Principal Opportunities Fund IV Delaware GP Inc. ("Fund IV Delaware GP"), the general partner of Fund IV Delaware, and has the sole power to appoint and remove directors of Fund IV Delaware GP. OCM Principal Opportunities Fund IV GP Ltd. ("Fund IV GP Ltd.") is the general partner of OCM Principal Opportunities Fund IV GP, L.P. ("Fund IV GP"), which is the general partner of Fund IV. GP I is the sole shareholder of Fund IV GP Ltd. and has the sole power to appoint and remove directors of Fund IV GP Ltd. By virtue of their relationship to Fund IV Delaware, (a) GP I, (b) Fund IV GP, (c) Fund IV GP Ltd., (d) Fund IV Delaware GP and (e) Fund IV may be deemed to have beneficial ownership of the shares owned by Fund IV Delaware. Mr. Kaplan and Mr. Beck are the portfolio managers for Fund IV. Mr. Kaplan, Mr. Beck, GP I, Fund IV GP, Fund IV GP Ltd., Fund IV Delaware GP and Fund IV disclaim beneficial ownership of the securities held by Fund IV Delaware, except to the extent of any pecuniary interest therein.

Oaktree Capital I, L.P. ("Capital I") is the general partner of GP I. OCM Holdings I, LLC ("Holdings I") is the general partner of Capital I. Oaktree Holdings, LLC ("Holdings LLC") is the managing member of Holdings I. By virtue of their relationship to Fund III, Fund IIIA and Fund IV Delaware, (a) Holdings LLC, (b) Holdings I and (c) Capital I, may be deemed to have beneficial ownership of the shares owned by Fund III, Fund IIIA and Fund IV Delaware. Holding LLC, Holdings I and Capital I disclaim beneficial ownership of the securities held by Fund III, Fund IIIA and Fund IV Delaware, except to the extent of any pecuniary interest therein.

Oaktree Holdings, Inc. ("Holdings Inc.") is the general partner of Oaktree, who is the manager of OCM EXCO. By virtue of their relationship to OCM EXCO, (a) Oaktree and (b) Holdings Inc. may be deemed to have beneficial ownership of the shares owned by OCM EXCO. Bruce Karsh is the President of Oaktree and is the portfolio manager for the funds that own OCM EXCO. Mr. Karsh, Oaktree and Holdings, Inc. disclaim beneficial ownership of the securities held by OCM EXCO, except to the extent of any pecuniary interest therein.

Oaktree Capital Group, LLC ("OCG") is the managing member of Holdings LLC and the sole shareholder of Holdings Inc. Oaktree Capital Group Holdings, L.P. ("OCGH") is the holder of a substantial majority of the voting units of OCG and has the ability to appoint and remove directors of OCG. Oaktree Capital Group Holdings GP, LLC ("OCGH GP") is the general partner of OCGH. OCGH GP is a limited liability company managed by an executive committee, the members of which are Howard S. Marks, Bruce A. Karsh, Sheldon M. Stone, Larry W. Keele, Stephen A. Kaplan, John B. Frank, David Kirchheimer and Kevin L. Clayton (collectively, the "Principals"). By virtue of their relationship to the Funds, (a) OCGH GP, (b) OCGH, (c) OCG and (d) each of the Principals may be deemed to have beneficial ownership of the shares owned by the Funds. OCGH GP, OCGH, OCG and each of the Principals hereby disclaims beneficial ownership of the securities of the Fund, except to the extent of any pecuniary interest therein.

In addition, the Funds also beneficially own (i) 50,000 shares which represent the vested portion of a stock option to purchase 50,000 shares of our Common Stock issued to B. James Ford, a Managing Director of Oaktree, as an initial grant upon becoming one of our directors, (ii) 7,500 shares which represent the vested portion of a stock option to purchase 15,000 shares of our Common Stock issued to Mr. Ford on December 1, 2009 and (iii) 1,250 shares which represent the vested portion of a stock option to purchase 5,000 shares of our Common Stock issued to Mr. Ford on November 5, 2010. These stock options are held directly by Mr. Ford for the benefit of the Funds. Pursuant to the policies of Oaktree, Mr. Ford must hold these stock options on behalf of and for the sole benefit of the Funds. Mr. Ford disclaims beneficial ownership of these securities, except to the extent of any indirect pecuniary interest therein. Also includes 12,500 shares subject to a stock option held by Vincent J. Cebula, one of our directors and formerly a Managing Director of Oaktree. In connection with Mr. Cebula's departure from Oaktree, Mr. Cebula agreed to remit to the Oaktree Funds any realized after-tax benefit earned by Mr. Cebula with respect to 12,500 of his then vested stock option awards.

(3) Based solely on the information contained in the Schedule 13G/A filed with the SEC on February 14, 2011.

(4) Includes (i) 6,005,951 shares of our Common Stock held by Ares Corporate Opportunities Fund, L.P. ("ACOF"), (ii) 45,262 shares of our Common Stock held by ACOF EXCO, L.P. ("ACOF EXCO"), (iii) 262,630 shares of our Common Stock held by ACOF EXCO 892 Investors, L.P. ("ACOF 892"), (iv) 3,883,157 shares of our Common Stock held by Ares Corporate Opportunities Fund II, L.P. ("ACOF II"), (v) 1,050,525 shares of our Common Stock held by Ares EXCO, L.P. ("Ares EXCO") and (vi) 1,645,262 shares of our Common Stock held by Ares EXCO 892 Investors, L.P. ("Ares 892").

The general partner of each of ACOF, ACOF EXCO and ACOF 892 is ACOF Management, L.P. ("ACOF Management") and the general partner of ACOF Management is ACOF Operating Manager, L.P. ("ACOF Operating Manager"). The general partner of each of ACOF II, Ares EXCO and Ares 892 is ACOF Management II, L.P. ("ACOF Management II") and the general partner of ACOF Management II is ACOF Operating Manager II, L.P. ("ACOF Operating Manager II"). Each of ACOF Operating Manager and ACOF Operating Manager II are indirectly owned by Ares Management LLC ("Ares") which, in turn, is indirectly controlled by Ares Partners Management Company LLC, which in turn is managed by an executive committee. Each of the members of the executive committee and the foregoing entities and the partners, members and managers thereof (other than ACOF, ACOF EXCO, ACOF 892, ACOF II, Ares EXCO and Ares 892, in each case with respect to the shares owned of record by such entity) expressly disclaims beneficial ownership of these shares of our Common Stock, except to the extent of any pecuniary interest therein.

Also includes (i) 50,000 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 upon becoming one of our directors in March 2007, (ii) 7,500 shares which represent the vested portion of a stock option to purchase 15,000 shares of our Common Stock issued to Mr. Serota on December 1, 2009 and (iii) 1,250 shares which represent the vested portion of a stock option to purchase 5,000 shares of our Common Stock issued to Mr. Serota on November 5, 2010. These stock options are held by Mr. Serota for the benefit of Ares. Pursuant to the policies of Ares, Mr. Serota holds these stock options as a nominee for the sole benefit of Ares and has assigned all economic, pecuniary and voting rights to Ares. Mr. Serota expressly disclaims beneficial ownership of these securities, except to the extent of any indirect pecuniary interest therein.

(5) Based solely on the information contained in the Schedule 13D/A filed with the SEC on February 4, 2011.

Executive Officers and Directors

Beneficial owner	Shares(1)	Options exercisable within 60 days	Percentage of shares outstanding
Named Executive Officers			
Douglas H. Miller(2)	6,537,434	1,969,350	3.0%
Stephen F. Smith(3)	1,082,685	576,550	*
William L. Boeing	637,475	628,375	*
Harold L. Hickey(4)	550,787	286,400	*
Mark E. Wilson(5)	163,183	127,900	*
Directors			
Jeffrey D. Benjamin(6)	544,424	58,750	*
Vincent J. Cebula(7)	58,750	58,750	*
Earl E. Ellis(8)	631,863	58,750	*
B. James Ford(9)	58,750	58,750	*
Mark Mulhern(10)	40,407	33,750	*
T. Boone Pickens, Jr.(11)	10,667,850	58,750	5.0%
Jeffrey S. Serota(12)	58,750	58,750	*
Robert L. Stillwell(13)	140,376	58,750	*
All executive officers and directors as a group (13 persons)	21,172,734	4,033,575	9.7%

(1) Includes the options exercisable within 60 days of April 15, 2011 shown in the options column.

(2) Includes 406,225 shares of our Common Stock held in various trusts for the benefit of immediate family members and 15,111 shares held in a 401(k) account.

(3) Includes 75,000 shares of our Common Stock held in various trusts for the benefit of immediate family members. Includes 422,521 shares of Common Stock held in a margin account with a brokerage firm and pledged as collateral security for the repayment of debit balances, if any, in such account and 8,614 shares held in a 401(k) account.

(4) Includes 9,922 shares of our Common Stock held in a 401(k) account.

(5) Includes 1,333 shares of our Common Stock held in a 401(k) account.

(6) Includes the right to acquire 23,671 shares of our Common Stock pursuant to the Director Plan granted to Mr. Benjamin as deferred compensation in lieu of cash for his service on our Board of Directors and committees. 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 Director Plan and (2) a “Change in Control” under the Director Plan. See “Item 11. Executive Compensation—Director Compensation” for a discussion of the Director Plan.

(7) These shares represent the vested portion of (i) a stock option to purchase 50,000 shares of our Common Stock issued to Mr. Cebula as an initial grant upon becoming one of our directors in March 2007, (ii) a stock option to purchase 15,000 shares of our Common Stock issued to Mr. Cebula on December 1, 2009 and (iii) a stock option to purchase 5,000 shares of our Common Stock issued to Mr. Cebula on November 5, 2010. Includes 12,500 shares subject to a stock option held by Vincent J. Cebula, one of our directors and formerly a Managing Director of Oaktree. In connection with Mr. Cebula’s departure from Oaktree, Mr. Cebula agreed to remit to the Oaktree Funds any realized after-tax benefit earned by Mr. Cebula with respect to 12,500 of his then vested stock option awards.

(8) Includes 11,110 shares of our Common Stock issued pursuant to the Director Plan to Mr. Ellis in lieu of cash as compensation for his service on our Board of Directors and committees. See “Item 11. Executive Compensation—Director Compensation” for a discussion of the Director Plan.

(9) These shares represent the vested portion of (i) a stock option to purchase 50,000 shares of our Common Stock issued to Mr. Ford, a Managing Director of Oaktree, as an initial grant upon becoming one of our directors in December 2007, (ii) a stock option to purchase 15,000 shares of our Common Stock issued to Mr. Ford on December 1, 2009 and (iii) a stock option to purchase 5,000 shares of our Common Stock issued to Mr. Ford on November 5, 2010. These stock options are held directly by Mr. Ford for the benefit of the Oaktree Funds. Pursuant to the policies of Oaktree, Mr. Ford must hold these stock options on behalf of and for the sole benefit of the Oaktree Funds and has assigned all economic, pecuniary and voting rights to the Oaktree Funds. Mr. Ford disclaims beneficial ownership of these securities, except to the extent of any indirect pecuniary interest therein. The shares reported for Mr. Ford do not include shares of our Common Stock held directly by certain of the Oaktree Funds. Mr. Ford disclaims beneficial ownership of these securities, except to the extent of any indirect pecuniary interest therein.

(10) In connection with Mr. Mulhern’s appointment to our Board of Directors on February 1, 2010, Mr. Mulhern was granted an option to purchase 65,000 shares of our Common Stock, of which 32,500 have vested. Mr. Mulhern was granted an option to purchase 5,000 shares of our Common Stock on November 5, 2010, of which 1,250 have vested. Also includes 1,657 shares of our Common Stock issued pursuant to the Director Plan to Mr. Mulhern in lieu of cash as compensation for his service on our Board of Directors and committees.

(11) Includes 58,750 shares of our Common Stock subject to stock options that are exercisable within 60 days of the April 15, 2011. Includes 10,619,100 shares of Common Stock held in an account with a bank and pledged as collateral security for the repayment of debit balances, if any, in such account.

(12) 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, all of which have vested. Mr. Serota was granted an option to purchase 15,000 shares of our Common Stock on December 1, 2009, of which 7,500 have vested. Mr. Serota was granted an option to purchase 5,000 shares of our Common Stock on November 5, 2010, of which 1,250 have vested. All of 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 referred to in note 4 to the beneficial ownership table for "Holders of more than 5%" above, with respect to which Mr. Serota disclaims beneficial ownership, except to the extent of any indirect pecuniary interest therein.

(13) Includes the right to acquire 4,926 shares of our Common Stock pursuant to the Director Plan granted to Mr. Stillwell as deferred compensation in lieu of cash for his service on our Board of Directors and committees. 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 Director Plan and (2) a "Change in Control" under the Director Plan. See "Item 11. Executive Compensation—Director Compensation" for a discussion of the Director Plan.

* Less than 1%.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Transactions with Related Persons

Corporate use of personal aircraft

We periodically charter, for company business, two 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 these 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 we believe is cost effective for us and our shareholders. As a result, EXCO's 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 certain members of our senior management. On limited occasions, executives authorized to use a chartered aircraft for business travel may, if space allows, bring family members or guests along on the trip provided they have the prior approval of certain members of our senior management. 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 that the aircraft are 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 to ascertain hourly flight rates for aircraft of comparable size and equipment in relation to DHM Aviation, LLC's aircrafts. This survey also ascertains other charges (including fuel surcharges) invoiced by such charter operators. Based on the results of such survey, senior management recommends to the audit committee appropriate revisions, if any, to the charter rates and fuel surcharges. The audit committee then establishes hourly rates and fuel surcharges EXCO will pay for the upcoming calendar year for the use of the aircraft. The present hourly rate paid by EXCO for use of these aircraft is in line with the market rate for similar aircraft. In addition, EXCO pays for customary out-of-pocket catering expenses, landing fees and excise taxes invoiced for a flight and any out-of-pocket expenses incurred by the pilots.

In August 2009, the audit committee approved a rate of $5,400 per flight hour plus a $400 per flight hour surcharge for the larger aircraft and a rate of $3,700 per flight hour plus a $400 per flight hour surcharge for the smaller aircraft. In November 2010, the rate for the larger aircraft was reduced to $5,300 per flight hour plus a $300 per flight hour fuel surcharge.

From January 1, 2010 through April 15, 2011, expenses incurred by EXCO payable directly to DHM Aviation, LLC or indirectly through an invoicing agent for use of these aircraft aggregated $1.1 million.

In August 2010, the Company purchased a jet aircraft for corporate purposes. Since that time, the Company primarily uses its own aircraft for business travel and charters Mr. Miller's aircraft less frequently when deemed necessary by our senior management.

Subcontractor relationship with Jeff Smith

Jeff Smith, the son of Stephen F. Smith, our President, Chief Financial Officer and one of our directors, owns a 50% interest in S&S Directional Drilling, LLC ("S&S"). One of EXCO's vendors, Select Energy Services, LLC ("Select"), or its affiliates subcontracts with S&S to provide equipment for use in connection with services provided by Select or its affiliates to EXCO. From January 1, 2010 through April 15, 2011, S&S was paid approximately $7.7 million by Select and/or its affiliates for the use of equipment in connection with services provided to EXCO.

Consulting relationship with Penny Wilson

Penny Wilson, the spouse of Mark E. Wilson, our Vice President, Chief Accounting Officer and Controller, was retained by us as a consultant during 2010 and 2011 primarily to support certain marketing and operational functions. From January 1, 2010 through April 15, 2011, fees paid to Ms. Wilson totaled approximately $171,000.

Audit Committee Review

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 that are required to be disclosed under Item 404 of Regulation S-K.

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 the 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 Company (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 our 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 are 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 J. Cebula, Earl E. Ellis, B. James Ford, Mark Mulhern, Jeffrey S. Serota, Robert L. Stillwell and T. Boone Pickens. 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.

On October 29, 2010, our Chairman and Chief Executive Officer, Douglas H. Miller, presented a letter to our Board of Directors indicating an interest in acquiring all of the outstanding shares of our stock not already owned by Mr. Miller for a cash purchase price of $20.50 per share. The proposal does not represent a definitive offer and there is no assurance that a definitive offer will be made or accepted, that any agreement will be executed or that any transaction will be consummated. See "Note 19. Acquisition Proposal" of the notes to our consolidated financial statements for further information regarding the proposal and for information regarding certain lawsuits against the Company or members of the Board of Directors in connection with the proposal.

In October 2006, the Company completed the acquisition of Winchester Energy Company, Ltd. from Progress Fuels Corporation, a subsidiary of Mr. Mulhern's employer, Progress Energy, Inc., or the Winchester Acquisition. Mr. Mulhern was the president of Progress Fuels Corporation at the time of the Winchester Acquisition. The Winchester Acquisition was the largest acquisition in the Company's history at that time and was the foundation for the Company's position in the Haynesville shale. No disputes or other claims between the Company and Progress Fuels Corporation have occurred in connection with the Winchester Acquisition. This relationship does not disqualify Mr. Mulhern from being deemed an independent director for NYSE purposes under the objective criteria. The Board of Directors has determined that this relationship does not interfere with his ability to exercise independent judgment on behalf of the Company.

Item 14. Principal Accounting Fees and Services

Audit Fees

Aggregate fees for professional services provided to us by our principal accountant, KPMG LLP, for the years ended December 31, 2010 and 2009 were as follows:

	2010	2009
	(in thousands)	
Audit Fees(a)	$2,165	$2,533
Audit-Related Fees(b)	204	150
Tax Fees(c)	75	70
All Other Fees(d)	15	69
Total	$2,459	$2,822

(a) Fees for audit services include fees associated with the annual audit, the reviews of EXCO's quarterly reports on Form 10-Q and Sarbanes-Oxley compliance test work.
(b) Audit-related fees principally include costs incurred related to accounting consultations related to generally accepted accounting principles and the application of generally accepted accounting principles to proposed transactions.
(c) Tax fees include tax compliance and tax planning.
(d) All other fees principally include costs incurred related to our enterprise risk assessment.

In considering the nature of the services provided by KPMG, 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 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, Financial Statement Schedules.

(a)(1) See Part II—Item 8. Financial Statements and Supplementary Data of our Form 10-K filed on February 24, 2011.

(a)(2) None.

(a)(3) See "Index to Exhibits" for a description of our exhibits.

(b) See "Index to Exhibits" for a description of our exhibits.

(c) None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

EXCO RESOURCES, INC.

Date: April 19, 2011

By: /s/ DOUGLAS H. MILLER

Douglas H. Miller
Chairman and Chief Executive Officer

Index to 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.
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of Chief Executive Officer and Chief Financial Officer of EXCO Resources, Inc., filed herewith.

DIRECTORS

Douglas H. Miller
Chairman of the Board and Chief Executive Officer
EXCO Resources, Inc.

Stephen F. Smith
Vice Chairman of the Board, President and Chief Financial Officer
EXCO Resources, Inc.

Jeffrey D. Benjamin [1,2,3]
Senior Advisor
Cyrus Capital Partners, LP

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

B. James Ford [2,3]
Managing Director
Oaktree Capital Management, L.P.

Mark F. Mulhern [1,2]
Chief Financial Officer
Progress Energy, Inc.

Boone Pickens
Chairman and Chief Executive Officer
BP Capital LP

Jeffrey S. Serota [1,2,3]
Senior Partner
Ares Management, LLC

Robert L. Stillwell [2,3]
General Counsel
BP Capital LP

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

OFFICERS

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

Stephen F. Smith
Vice Chairman of the Board, President and Chief Financial Officer

Harold L. Hickey
Vice President and Chief Operating Officer

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

William L. Boeing
Vice President, General Counsel and Secretary

Michael R. Chambers, Sr.
Vice President of Operations and General Manager-East Texas/North Louisiana

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

Steve Estes
Vice President of Marketing

Joe D. Ford
Vice President of Human Resources

Russell D. Griffin
Vice President of Environmental, Health and Safety

Richard L. Hodges
Vice President of Land and Assistant Secretary

John D. Jacobi
Vice President of Business Development

Harold H. Jameson
Vice President and General Manager - East Texas/North Louisiana JV

Tommy Knowles
Vice President and General Manager - Permian Division and Supply Chain

Stephen E. Puckett
Vice President of Reservoir Engineering

J. Douglas Ramsey, Ph.D.
Vice President - Finance, Special Assistant to the Chairman and Treasurer

Paul B. Rudnicki
Vice President of Financial Planning and Analysis

Marcia R. Simpson
Vice President of Engineering

Andrew C. Springer
Vice President of Tax

Robert L. Thomas
Chief Information Officer

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
2323 Victory Avenue, Suite 700
Dallas, TX 75219

Annual Meeting
The 2011 Annual Meeting of Shareholders will be held on Thursday, October 6, 2011 at 10:00 am Dallas time, at the Westin Park Central, Salon D, 12720 Merit Drive, Dallas, Texas 75251.

Stock Transfer Agent
Continental Stock Transfer & Trust Company
Communications concerning transfer or exchange requirements, lost certificates, shareholdings or changes of address should be directed to:
17 Battery Place, 8th Floor
New York, New York 10004
212-509-4000

Number of Common Shareholders
11,423
(As of July 20, 2011)

EXCO Resources, Inc.
12377 Merit Drive, Suite 1700, Dallas, TX 75251
www.excoresources.com