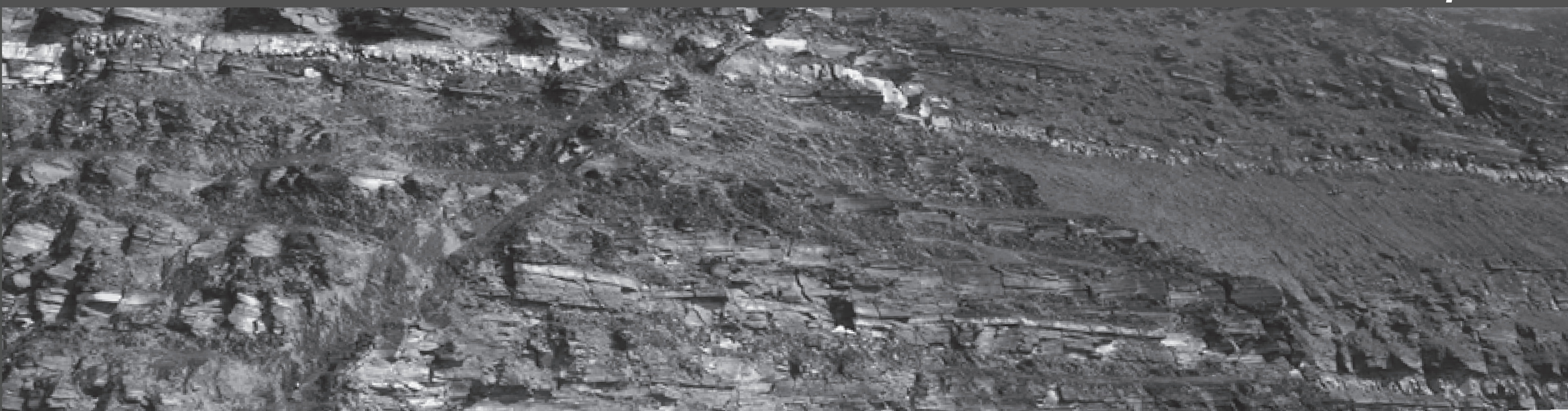
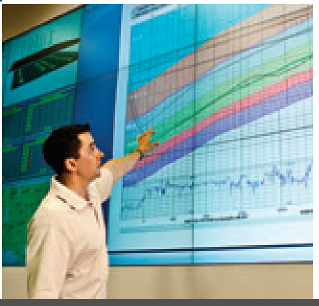
EXCO Resources, Inc.

2012 Annual Report





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Mission Statement

EXCO Resources, Inc. is a natural gas and oil company engaged in the acquisition, 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.

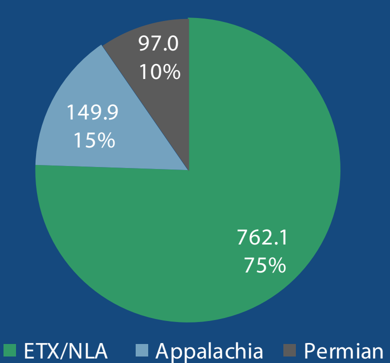
2012 Highlights

- Managed EXCO through a challenging natural gas price environment in 2012
- Reduced cash general and administrative costs by 24%, direct operating costs by 11% and capital expenditures by 48% compared to 2011
- Continued successful asset development across all areas

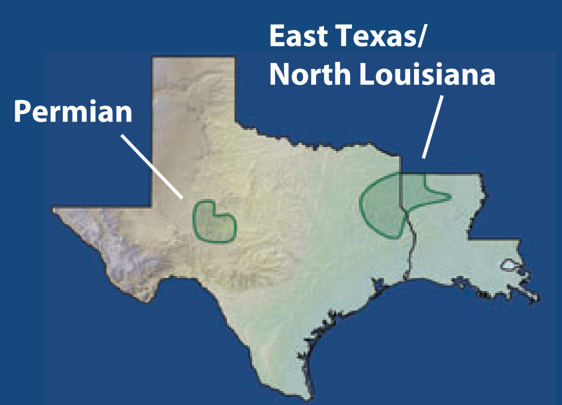
Core Areas of Operation

- Haynesville Shale – ETX/NLA
  - ~58,000 net acres
  - 454 Bcfe of proved reserves
- Marcellus Shale – Appalachia
  - ~128,000 net acres
  - 99 Bcfeof proved reserves

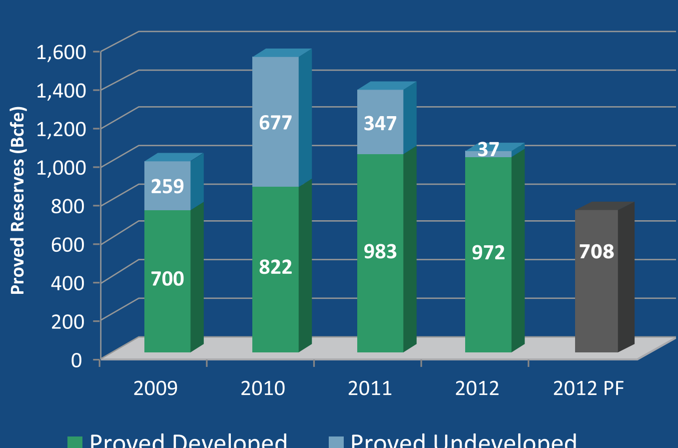
Proved Reserves Breakdown (Bcfe)*



*Proved Reserves reflect year-end SEC pricing

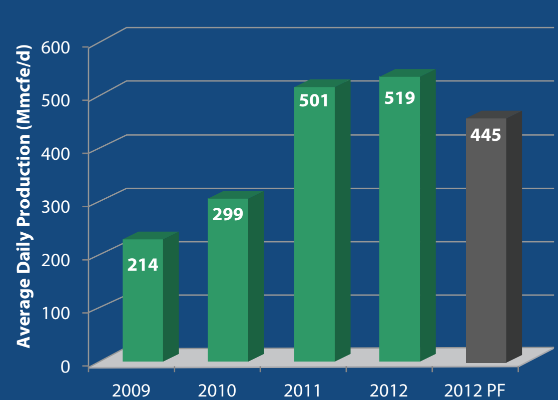


Proved Reserves*



*Proved Reserves reflect year-end SEC pricing. Pro forma proved reserves for 2012 are presented as if the EXCO/HGI Partnership occurred on January 1, 2012.

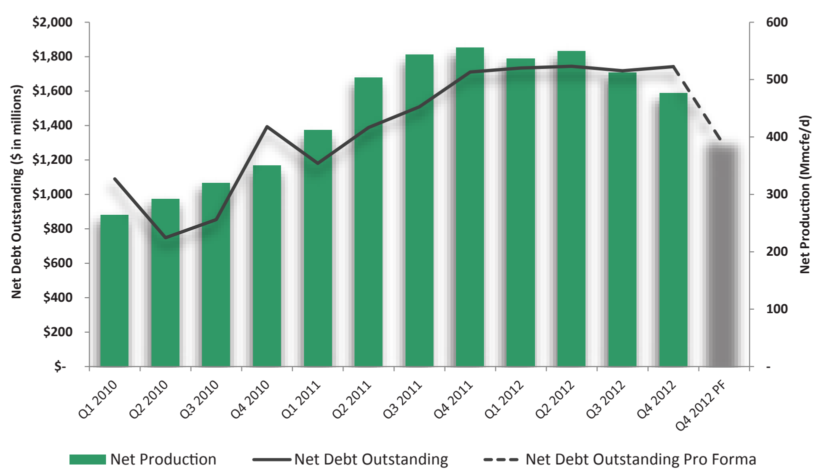
Average Daily Production*



*Historical production volumes adjusted as if 2009 and 2010 divestitures and joint ventures occurred on January 1, 2009. Pro forma production for 2012 is presented as if the EXCO/HGI Partnership occurred on January 1, 2012.

Dear Fellow Shareholders,

As we entered 2012, we anticipated a challenging year. EXCO and other companies with significant natural gas reserves were confronted with an extended period of depressed domestic natural gas prices arising from accelerated shale resource development and unusually warm winter weather, which created excess supplies of natural gas in the United States. In response, we undertook numerous actions to position ourselves to meet the challenges that low prices presented. Specifically, we reduced our operated drilling rig count from 24 rigs at the beginning of the year to five by the end of 2012 and reduced employee headcount by 16 percent and contractor headcount by 62 percent. Capital expenditures were reduced by approximately 48 percent from our original budget and operating and general and administrative costs, on a per Mcfe basis, were reduced 11 percent and 24 percent, respectively. Financially, these actions resulted in EXCO maintaining cash expenditures within cash flow. In fact, consolidated debt was reduced by $40 million during the year.



Operationally, 2012 was successful in spite of the low natural gas prices. Our production volumes increased by three percent from 2011, principally from our Haynesville and Marcellus shale operations. In our core DeSoto Parish, Louisiana area, our average drilling and completion costs were reduced from an average of $9.5 million per well in the fourth quarter of 2011 to approximately $8.0 million per well in 2012. Estimated ultimate recoverable reserves in many of our Haynesville shale properties were subject to upward reserve revisions.

Since we commenced operations in the Haynesville shale play, we have gained substantial technical knowledge of the Haynesville reservoirs. Initially, we were conservative with our reserve booking policy as the play was in its early development stages and technical data was limited. We are pleased with the overall quality of the reservoir and the results our operations team has achieved reducing drilling and completion costs. In our Marcellus shale region, we also experienced lower average well costs and we have been encouraged by the performance of recently completed wells.

In February 2013, we contributed conventional non-shale oil and natural gas properties from our East Texas, North Louisiana and Permian Basin regions to a newly-formed, private partnership. We received $573 million for our contribution, which was applied to reduce our debt, and retained a 25.5 percent interest in the partnership. We believe this transaction was an important step toward enhancing our shareholder value as it provides us with liquidity to execute our growth strategy as well as a vehicle to make acquisitions of conventional assets. In March 2013, the partnership closed its first acquisition by acquiring incremental working interests in properties already operated by the partnership.

Current market cycle presents compelling acquisition economics

While recent increases in natural gas prices are encouraging, we continue to manage our assets as if natural gas prices will remain depressed throughout 2013. Accordingly, our strategy within our existing operating areas during 2013 is expected to be similar to 2012 by focusing on cost controls and preserving liquidity. Our capital budget for 2013 is $273 million, approximately 45% less than 2012 capital expenditures. As a result of reduced drilling expenditures in the budget and the impact from the February 2013 private partnership transaction, we expect 2013 production volumes and operating cash flows to decline from 2012. To mitigate these declines, we have developed a growth strategy that is structured around the following themes:

- Shifting our emphasis from drilling to a focus on producing property acquisitions with undeveloped upside; and
- Leveraging partnerships to accelerate growth.

Realized hedging gains were $202.1 million

The current market cycle presents compelling acquisition economics. Our acquisition targets include properties within our existing core operating areas as well as new regions. While the acquisition focus will continue to emphasize natural gas properties, liquids-rich assets are also being considered.

Utilization of partnership structures is being pursued to create opportunities to fund larger acquisitions and accelerate development of the locations associated with those acquisitions. These structures can also create opportunities to accelerate drilling of our existing undeveloped shale locations. We believe that sharing of costs through partnership structures creates flexibility to allocate our capital resources to multiple projects with attractive returns and allows us to emphasize acquisitions of proved developed producing properties.

We have historically used derivative financial instruments to mitigate price volatility and facilitate predictable cash flow. The use of derivatives remains a fundamental strategy in our company. As of March 31, 2013, approximately 60% of our expected 2013 natural gas production is covered by derivative financial instruments at an average price of $4.17 per Mcf.

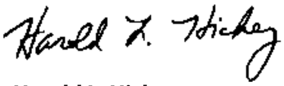
Our 2012 accomplishments and our plans for the future would not be possible without the dedication and innovation of our employees. While we reduced headcount due to economic conditions, we successfully retained a highly competent group of employees to manage us through the downturn and guide us into the future.

In closing, as announced in March 2013, Steve Smith, our former President and Chief Financial Officer, has decided to retire from EXCO effective June 1, 2013. We are grateful to Steve for his leadership and fortunate that he will remain available to EXCO as a consultant on future business matters. Hal Hickey has assumed the role of President in addition to his role as Chief Operating Officer and Mark Mulhern, the former chairman of EXCO's audit committee, joined the senior management team as our Executive Vice President and Chief Financial Officer.

We thank you for your support and look forward to executing our growth strategy during 2013 and beyond.

Sincerely,

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



Harold L. Hickey
President
and Chief Operating Officer

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 Form 10-K for the year ended December 31, 2012 , 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.

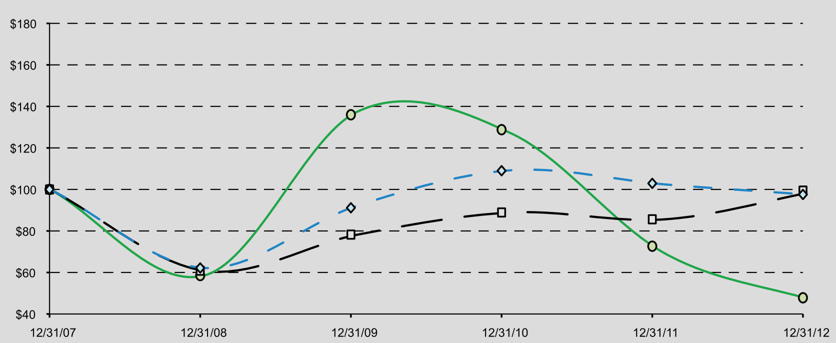
SEC and NYSE Certifications

The Form 10-K, included herein, which was filed by the company with the SEC for the fiscal year ending December 31, 2012, includes, 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 2012 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 December 31, 2007 would be worth on December 31, 2012) 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 of our common stock or the referenced indexes.



	Period Ending					
	12/31/07	12/31/08	12/31/09	12/31/10	12/31/11	12/31/12
EXCO Resources, Inc.	$ 100.00	$ 58.53	$137.57	$ 126.91	$ 69.07	$ 45.75
NYSE Composite Index	$ 100.00	$ 60.86	$ 78.24	$ 88.91	$ 85.62	$ 99.45
Crude Petroleum and Natural Gas Index	$ 100.00	$ 62.17	$ 92.27	$ 109.25	$ 102.41	$ 97.16

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

FORM 10-K

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

For the Fiscal Year Ended December 31, 2012

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

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 (§229.405 of this chapter) 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 Form10-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 February 19, 2013, the registrant had 217,571,115 outstanding shares of common stock, par value $0.001 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 approximately $1,025,810,000.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement on Schedule 14A to be furnished to shareholders in connection with its 2013 Annual Meeting of Shareholders are incorporated by reference in Part III, Items 10-14 of this Annual Report on Form 10-K.

EXCO RESOURCES, INC.

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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 29.

We are an independent oil and natural gas company engaged in the acquisition, exploration, exploitation, development and production of onshore U.S. oil and natural gas properties with a focus on shale resource plays. Our principal operations are conducted in certain key U.S. 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.

As of December 31, 2012, our Proved Reserves were approximately 1.0 Tcfe, of which 92.7% were natural gas and 96.3% were Proved Developed Reserves. As of December 31, 2012, the PV-10 and Standardized Measure of our Proved Reserves was approximately $696.1 million. For the year ended December 31, 2012, we produced 189.9 Bcfe of oil and natural gas resulting in a Reserve Life of approximately 5.3 years (See "Summary of geographic areas of operations" for a reconciliation of PV-10 to the Standardized Measure and discussion regarding our Reserve Life).

Recent developments

On February 14, 2013, we formed a partnership with Harbinger Group Inc., or HGI. Pursuant to the agreements governing the transaction, we contributed our conventional non-shale assets in East Texas and North Louisiana and our shallow Canyon Sand and other assets in the Permian Basin of West Texas to the partnership, or the EXCO/HGI Partnership, in exchange for approximately $573.3 million of cash, after customary preliminary purchase price adjustments, and a 25.5% economic interest in the partnership. HGI owns the remaining 74.5% economic interest in the partnership. HGI contributed cash to us in the amount of approximately $348.3 million. The remaining proceeds we received were in the form of a cash distribution from the partnership of $225.0 million from a draw on the EXCO/HGI Partnership's credit agreement discussed below. The primary strategy of the EXCO/HGI Partnership will be to acquire conventional producing oil and natural gas properties to enhance asset value and cash flow.

In connection with its formation, the EXCO/HGI Partnership entered into a credit agreement, or the EXCO/HGI Partnership Credit Agreement, with an initial borrowing base of $400.0 million, of which $230.0 million was drawn at closing. Borrowings under the EXCO/HGI Partnership Credit Agreement are secured by the properties contributed to the EXCO/HGI Partnership and we do not guarantee the EXCO/HGI Partnership's debt.

Proceeds from the formation of the EXCO/HGI Partnership were used to reduce outstanding borrowings under our credit agreement, or the EXCO Resources Credit Agreement. As a result of this transaction, our borrowing base under the EXCO Resources Credit Agreement was reduced to $900.0 million.

Immediately following closing, the EXCO/HGI Partnership assumed an agreement to purchase all of the shallow Cotton Valley assets within our joint venture with an affiliate of BG Group plc, or BG Group, for $132.5 million, subject to customary closing adjustments. A deposit of $25.0 million was paid to BG Group when the agreement was executed. The transaction is expected to close in the first quarter of 2013 and funded with borrowings from the EXCO/HGI Partnership Credit Agreement. In connection with the acquisition of the properties from BG Group, the EXCO/HGI Partnership has requested an increase to the borrowing base under the EXCO/HGI Partnership Credit Agreement.

Our business strategy

Our primary strategy is to acquire, explore, exploit and develop oil and natural gas properties and leverage our expertise in shale resources into our existing operating areas and new regions. Our financing strategies to accomplish these objectives include the use of partnership structures, borrowings under the EXCO Resources Credit Agreement and capital markets when conditions are favorable. We also use derivative financial instruments to manage volatility in commodity prices.

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

  Our emphasis over the past four years has primarily been focused on shale resource plays consisting of undeveloped acreage. Acreage acquisitions differ from acquisitions of producing properties because the undeveloped acreage does not result in immediate production and cash flows or provide an incremental borrowing base increase under the EXCO Resources Credit Agreement. While we expect to continue evaluating acreage opportunities in our shale areas, our business development and technical staff are currently focusing on acquisitions of producing properties as a result of the current depressed natural gas price environment.

- ***Manage our liquidity in a low natural gas price environment***

  The price of natural gas has a history of volatility and over the past few years has experienced significant declines. Most of our revenues are derived from the sale of natural gas and our liquidity has been significantly impacted by low natural gas prices, especially in 2012. Our board of directors approved a capital expenditure budget of $273.0 million for 2013. We expect the capital expenditure program will be funded primarily by our operating cash flow. In addition, we are evaluating potential transactions which would further enhance our liquidity, including a sale of our interest in TGGT Holdings, LLC, or TGGT, additional divestitures of non-core assets, properties with higher operating costs, properties that are not strategic and other opportunistic divestitures, reductions in drilling and continuous evaluation of cost reduction initiatives in operating and general and administrative costs.

- ***Exploit 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 58,400 net acres in the Haynesville/Bossier shales and in Appalachia we currently hold approximately 128,100 net acres in the Marcellus shale.

  Since we commenced our horizontal drilling program in the Haynesville shale in 2008, we have spud 391 operated horizontal wells through December 31, 2012. We also own working interests in 178 Haynesville horizontal wells operated by others. We continue to work closely with our midstream operations to coordinate the timing of drilling and completing our wells, which allows us to bring production from new wells to market promptly after completion.

  We are parties to a joint venture with BG Group covering an undivided 50% interest in a substantial portion of our shale 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 with our subsidiary, EXCO Operating Company, LP, or EXCO Operating, serving as operator. TGGT is a 50/50 joint venture between us and BG Group which holds most of our East Texas/North Louisiana midstream assets.

  We have used a similar process in the Marcellus region that was used in the Haynesville shale, with principal activities focused on technical evaluations of our acreage holdings, appraisal wells and a disciplined development drilling program in Lycoming County, Pennsylvania. In 2013, our plans are to continue development initiatives in Northeast Pennsylvania and conduct a limited drilling program in Central Pennsylvania. A substantial portion of our shale resource play acreage is held-by-production which gives us flexibility to delay drilling if prices remain low without the threat of losing valuable leases.

  We are parties to a joint venture with BG Group covering our Marcellus shale acreage and shallow producing assets in the Appalachia region, or the Appalachia JV. EXCO and BG Group each own an undivided 50% interest in the Appalachia JV and a 49.75% working interest in the joint venture's properties. The remaining

0.5% working interest is owned by a jointly owned operating entity, or OPCO, which manages the Appalachia JV operations. Pursuant to another joint venture with BG Group, we each own a 50% interest in a midstream company, or the Appalachia Midstream JV, which will develop infrastructure and provide take-away capacity in the Marcellus shale.

- ***Creation of additional private partnerships or other financing mechanisms to facilitate producing property acquisitions***

  We have used and may in the future use joint ventures or partnership structures to facilitate producing property acquisitions by sharing the cost of such acquisitions with third parties.

  On February 14, 2013, we formed the EXCO/HGI Partnership which owns our conventional shallow Cotton Valley assets in East Texas and North Louisiana and our Canyon Sand assets in the Permian Basin of West Texas. The EXCO/HGI Partnership subsequently agreed to purchase BG Group's interest in the shallow Cotton Valley assets located in East Texas/North Louisiana. Following this acquisition, BG Group will no longer own shallow interests in the East Texas/North Louisiana JV.

  The EXCO/HGI Partnership created liquidity for us to execute our business strategy. In addition, we retained a significant interest in the upside potential of these assets if natural gas prices increase or if we are successful growing the EXCO/HGI Partnership.

  In the fourth quarter of 2012, we acquired prospective acreage in the Permian Basin with deep rights which have horizontal drilling potential. We are negotiating with a joint venture partner to develop this acreage.

- ***Maintain financial flexibility***

  We employ the use of debt and equity, joint ventures, operating cash flow 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 and protects our returns on investments and capital structure. The EXCO Resources Credit Agreement has a $900.0 million borrowing base with unused borrowing capacity of $358.3 million as of February 19, 2013 (see “Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations-Our liquidity, capital resources and capital commitments-Overview”). We also have $750.0 million aggregate principal amount of 7.5% senior notes outstanding that mature on September 15, 2018, or the 2018 Notes.

  Currently, we have derivative financial instruments covering approximately 60.0% of our projected natural gas production for 2013. We plan to add to the derivative portfolio as opportunities arise.

- ***Manage our asset portfolio and associated costs***

  We periodically review our properties to identify cost savings opportunities and divestiture candidates and 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 expect to continue to grow by leveraging our management and technical team's experience, developing our shale resource plays, exploiting our multi-year inventory of development drilling locations and seeking acquisition opportunities both inside and outside of our existing operating areas. We employ the use of debt and equity, joint ventures, operating cash flows and 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.

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 Basin. Our properties are generally characterized by:

  - multi-year inventory of development drilling and exploitation projects;
  - high drilling success rates;
  - significant unproved reserves and resources;
  - exploration opportunities; and
  - long reserve lives.

- ***Skilled technical personnel with supplemental support and expertise from BG Group***

  We have accumulated a significant number of skilled, multi-disciplined technical and operational personnel who have successfully implemented a significant horizontal drilling program. In addition, our access to BG Group's personnel in our shale joint ventures complements the execution of our strategies.

- ***Operational control***

  We operate a significant portion of our properties, coupled with substantial 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, 2012, we operated 7,616 of our 8,179 gross wells, or wells representing approximately 96.0% 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 30 years of industry experience in acquiring, exploring, exploiting and developing oil and natural gas properties.

Significant 2012 activities

During 2012, the natural gas markets experienced significant declines in natural gas prices, largely due to accelerated shale resource development and unusually warm winter weather, which created excess supplies of natural gas in the United States. In response to the low natural gas price environment, our 2012 activities were dedicated to initiating cost controls, reducing and prioritizing our drilling programs and seeking joint venture partners for our conventional assets. We significantly reduced our operational spending program in 2012. We entered 2012 with 24 operated drilling rigs and exited 2012 with five operated drilling rigs. Please see “Our development and exploitation project areas - East Texas and North Louisiana - Haynesville shale operational effectiveness” and “Our development and exploitation project areas - Appalachia - Marcellus shale operational effectiveness” for additional information concerning the cost controls implemented in the Haynesville and Marcellus shale areas.

Plans for 2013

We expect natural gas prices to remain depressed in 2013. Accordingly, our strategy in 2013 is expected to be similar to 2012 and we plan to focus on cost controls and preserve liquidity. As a result, we expect production volumes and operating cash flows, particularly from our shale areas, to decline. Presently, our approved capital budget for 2013 is $273.0 million, or approximately 45% less than the actual capital expenditures for 2012. Our current acquisition strategy is to focus on producing properties with upside development opportunities. While we expect to continue to evaluate acreage acquisition opportunities in our shale areas, we believe the current low price natural gas environment provides greater opportunities from producing property acquisitions rather than undeveloped acreage acquisitions.

Cash and debt summary

A summary of our cash, outstanding long-term debt as of December 31, 2012 and February 19, 2013 and a brief description of the EXCO Resources Credit Agreement and the 2018 Notes is presented below.

(in thousands)	December 31, 2012	February 19, 2013
Cash (1)	$ 115,729	$ 86,413
Drawings under the EXCO Resources Credit Agreement	1,107,500	534,235
2018 Notes (2)	750,000	750,000
Total debt	1,857,500	1,284,235
Net debt	$ 1,741,771	$ 1,197,822
Borrowing base (3)	$ 1,300,000	$ 900,000
Unused borrowing base (4)	$ 185,393	$ 358,258
Unused borrowing base plus cash (1) (4)	$ 301,122	$ 444,671

(1) Includes restricted cash of $70.1 million at December 31, 2012 and $71.4 million at February 19, 2013.
(2) Excludes unamortized bond discount of $8.5 million at December 31, 2012 and $8.4 million at February 19, 2013.
(3) Following formation of the EXCO/HGI Partnership, the borrowing base under the EXCO Resources Credit Agreement was reduced to $900.0 million to reflect the contribution of assets to the partnership.
(4) Net of $7.1 million and $7.5 million in letters of credit as of December 31, 2012 and February 19, 2013, respectively.

EXCO Resources Credit Agreement

The EXCO Resources Credit Agreement, as amended, matures on April 1, 2016 and had a borrowing base of $1.3 billion as of December 31, 2012, subject to semi-annual borrowing base redeterminations. Upon formation of the EXCO/HGI Partnership, the borrowing base was reduced to $900.0 million as a result of our contribution of certain oil and natural gas properties to the EXCO/HGI Partnership. EXCO is not a guarantor of the EXCO/HGI Partnership's debt.

2018 Notes

The 2018 Notes are guaranteed on a senior unsecured basis by our consolidated subsidiaries. All of our non-guarantor subsidiaries are considered unrestricted subsidiaries under the 2018 Notes, with the exception of our equity investment in OPCO.

EXCO/HGI Partnership Credit Agreement

As of February 14, 2013, the EXCO/HGI Partnership Credit Agreement had an initial borrowing base of $400.0 million and matures on February 14, 2018. The borrowing base of the EXCO/HGI Partnership Credit Agreement is subject to semi-annual redeterminations. In connection with the acquisition of shallow properties from BG Group, the EXCO/HGI Partnership has requested an increase to the borrowing base of the EXCO/HGI Partnership Credit Agreement. The EXCO/HGI Partnership Credit Agreement is a separate credit facility that is secured by the EXCO/HGI Partnership's assets. EXCO is not a guarantor of the EXCO/HGI Partnership's debt.

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, 2012:

Areas	Total Proved Reserves (Bcfe) (1) (3)	PV-10 (in millions) (1) (2)	Annual daily net production (Mmcfe)	Reserve Life (years) (4)
East Texas/North Louisiana	762.1	$ 377.8	450	4.6
Appalachia	149.9	91.1	44	9.3
Permian and other	97.4	227.2	25	10.8
Total	1,009.4	$ 696.1	519	5.3

Areas	Estimated drilling locations (5)	Total gross acreage	Total net acreage (6)
East Texas/North Louisiana	3,890	234,987	119,556
Appalachia	4,890	727,462	311,810
Permian and other	240	49,620	46,712
Total	9,020	1,012,069	478,078

(1) The total Proved Reserves, prepared in accordance with the rules and regulations of the Securities and Exchange Commission, or SEC, and PV-10 for non-shale properties, excluding future plugging and abandonment costs, 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 Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm located in Dallas, Texas. For each area set forth in the table, the Proved Reserves were extracted by our internal engineers from the reports prepared by Lee Keeling and NSAI. 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 reference prices using the simple average of the spot prices for the trailing 12 month period using the first day of each month beginning on January 1, 2012 and ending on December 1, 2012, of $2.76 per Mmbtu for natural gas and $94.71 per Bbl for oil, in each case adjusted for geographical and historical differentials. The price per barrel for NGLs was $46.57 per barrel and was computed on the 12 month average of realized prices in 2012. Market prices for oil, natural gas and NGLs are volatile (see “Item 1A. Risk Factors-Risks relating to our business”). We believe that PV-10, while not a financial measure in accordance with generally accepted accounting principles in the United States, 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, as of December 31, 2012 was $696.1 million. The Standardized Measure represents the PV-10 after giving effect to income taxes, and is calculated in accordance with the Financial Accounting Standards Board, or FASB, Accounting Standards Codification, or ASC, 932, *Extractive Activities, Oil and Gas*, or ASC 932. The PV-10 for 2012 was negatively impacted by the lower future revenues and future net cash flows that primarily resulted from a 33.0% decrease in the reference price for natural gas during 2012. These lower future net cash flows combined with our existing net operating loss carryforwards eliminated estimated future income taxes for the year ended December 31, 2012. 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.

(3) Our conventional shallow assets in East Texas/North Louisiana and the Permian area were contributed to the EXCO/HGI Partnership effective February 14, 2013. Using December 31, 2012 Proved Reserves, we contributed 404.8 Bcfe of Proved Reserves to the EXCO/HGI Partnership.

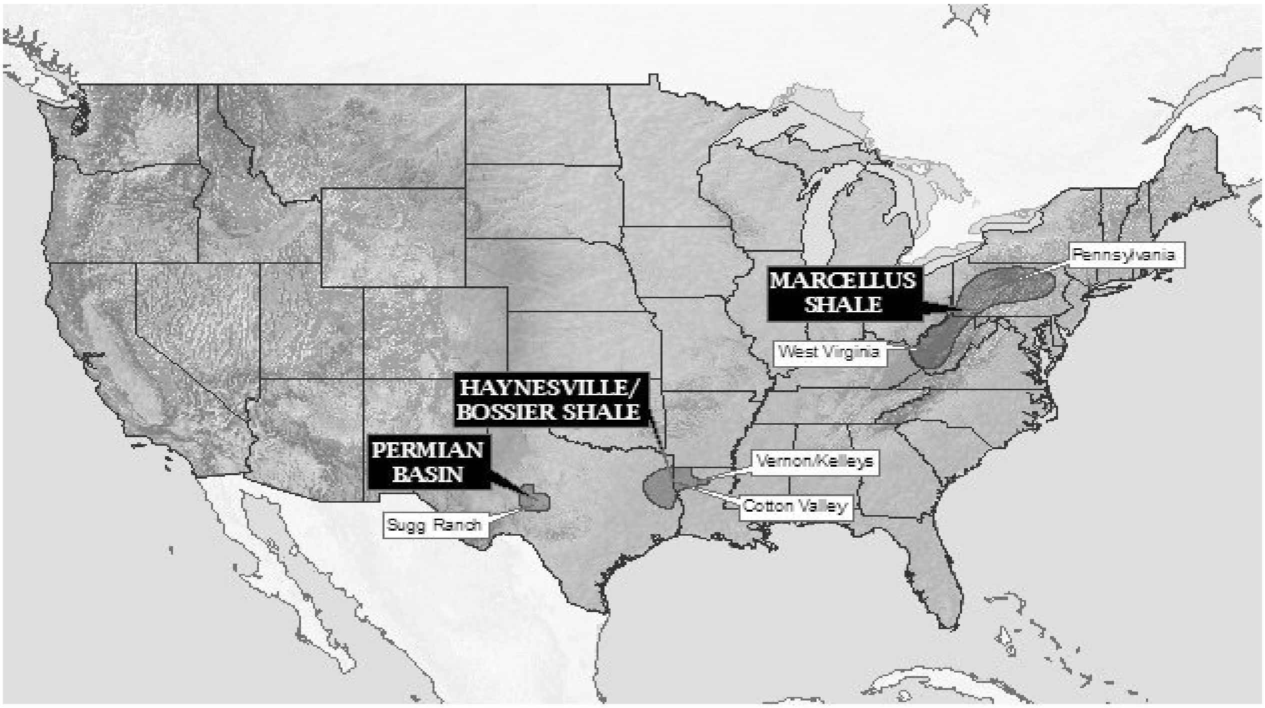
(4) Our computed Reserve Life as of December 31, 2012 was negatively impacted by significant declines in natural gas prices. As a result, our quantities of Proved Reserves declined, while our produced volumes remained high due to the high initial production volumes from horizontal wells, which reduces the mathematical computation.

(5) 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 drilling locations shown in the table, approximately 558 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").

(6) Includes 29,233, 6,904 and 19,275 net acres with leases expiring in 2013, 2014 and 2015, respectively. Approximately 76% of the scheduled expiring acreage is located within our shale resource plays.

Our development and exploitation project areas



East Texas and 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 development targets include the Haynesville and Bossier shales.

Currently, our emphasis is on development of our acreage in the Haynesville shale play where we hold approximately 58,400 net acres. The Haynesville shale is at depths of 12,000 to 14,500 feet and is being developed with horizontal wells that typically have 4,000 to 5,500-foot laterals resulting in 16,000 to 20,000 feet of total measured depth.

Through the EXCO/HGI Partnership, we will continue to produce from tight gas sand reservoirs from the Cotton Valley, Travis Peak, Pettet and Hosston formations at depths of 6,500 to 15,000 feet.

Haynesville shale

The Haynesville shale play is one of the most prolific 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 drilling program in the Haynesville shale play is concentrated in our Holly Field area in DeSoto Parish, Louisiana. In 2011, we averaged 22 operated drilling rigs in the play. In late 2011, we began a significant reduction in our Haynesville shale rig count due to low natural gas prices and averaged seven operated rigs in 2012. We are currently operating three drilling rigs in the Haynesville shale play.

Our current plans for Haynesville shale play for 2013 include utilizing three operated rigs to drill 26 wells. At the end of 2012, we had 19 wells that were drilled, cased and waiting on completion. Our 2013 program will include completion of all wells waiting on completion at the end of 2012. The total projected number of completions in 2013 is 42 wells. Since we commenced Haynesville shale horizontal drilling in 2008 through December 31, 2012, we have spud 391 operated horizontal wells and produced approximately 1.0 Tcf of gross natural gas to sales. As of December 31, 2012, we averaged a gross operated shale gas production rate of approximately 1.1 Bcf per day. Including non-operated volumes, we exited 2012 with net Haynesville shale production of 353.0 Mmcf per day.

Holly area

We continue to develop the Holly Area in DeSoto Parish on 80-acre spacing in a manufacturing mode utilizing multi-well pad development. Our current manufacturing process typically involves using three drilling rigs per 640-acre unit to simultaneously drill all wells in the unit, followed by one to two fracture stimulation fleets to efficiently complete all wells in the unit. We believe this approach to development maximizes value and recovery of reserves. As of December 31, 2012, we had developed 34 units on 80-acre spacing and plan to drill an additional four units during 2013. 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. At December 31, 2012, we had three drilling rigs running in the area and a total of 301 horizontal wells flowing to sales.

Shelby area

In 2010, we acquired a significant acreage position in the Shelby Area in East Texas, our second core area of the Haynesville shale play. Since this area had few producing wells at the time of acquisition, our initial efforts focused on delineating the acreage, establishing our base infrastructure in the area, determining productivity of the Haynesville and Bossier shales, testing different completion designs and evaluating different flowback methodologies.

In late 2011, we began our first spacing test to fully develop the Haynesville and Bossier shales in two units. To evaluate the performance of the various spacing patterns, we drilled a vertical monitor well solely for microseismic data acquisition and pressure monitoring purposes. This well was drilled and cased to a depth of 14,500 feet as a dedicated observation well. We monitored multiple fraction stimulation stages with downhole microseismic survey tools followed by installation of permanent downhole gauges to measure and monitor the reservoir pressure in the Haynesville shale as the unit produces. We believe this is a necessary commitment to understand reservoir performance and maximize the estimated ultimate recovery, or EUR. We used a monitor well with the same design in DeSoto Parish and it provided valuable reservoir information. This original monitor well is still in use today.

The testing and evaluation program is currently in the phase required to properly evaluate the Haynesville/Bossier shale well spacing to assess the proper development strategy. Our plans are to evaluate the performance of this spacing pilot before proceeding with additional unit development.

At December 31, 2012, we had no drilling rigs running in the Shelby area. We have suspended drilling in this area awaiting higher natural gas prices. As of December 31, 2012, we had a total of 70 operated horizontal wells flowing to sales with an average gross production rate of approximately 131.2 Mmcf per day (39.6 Mmcf per day net).

Haynesville shale operational effectiveness

Our operational focus has resulted in significant improvements in drilling and completion efficiencies and reduced well costs. In the fourth quarter of 2011, our wells in DeSoto Parish averaged total drilling and completion capital costs of $9.5 million per well. With our focused cost reduction and efficiency program, we drilled and completed wells for approximately $8.0 million per well during 2012, a 15.8% reduction from the fourth quarter of 2011. In DeSoto Parish we continue to achieve improved drilling time per well. We have set several drilling records in the play including single bit runs from surface to intermediate hole depth and multiple single bit runs from intermediate to production hole total depth, typically 16,500 feet. The number of days required to drill a 16,500 foot Haynesville horizontal well has been reduced 42.0% since early 2009 as a result of our operational efficiencies efforts. We are currently averaging 36 days from spud to rig release in the DeSoto Parish area and we are continuing to see improvements. The rig fleet we have working today has been highgraded and retained from the larger fleet we had working in 2011 and we strive to retain the core working groups, including both company personnel and service contractors who have developed strong teamwork skills. In addition to our success in reducing well costs attributable to drilling, we are also focused on more cost effective and optimized completions. Approximately 40.6% of our well cost is incurred during the completion phase. We have implemented cost effective and efficient design changes as part of our manufacturing program. We are currently utilizing one fracture stimulation fleet and continue to see greater consistency and efficiencies in our fracturing operations. We design our development program to flow gas directly to the sales line once the unit is completed. We have no wells that are delayed for completion due to waiting on pipeline construction. This is possible due to close coordination with our jointly-held midstream company, TGGT, which installs gathering lines in concert with our drilling operations in most of our development areas.

In 2012, we made a significant improvement in operating cost efficiency in our shale operations. Our direct operating costs are currently 31.6% lower than our average cost in the fourth quarter of 2011. This reduction in cost is the direct result of a variety of focused initiatives including a better salt water disposal process, better utilization of company personnel performing maintenance work, a more effective gas cooler utilization process and a more effective chemical program. We have a strong focus on operating expense management and reporting. A failure tracking database system is in place that enables us to be proactive in equipment repairs, and we accordingly expect additional cost improvements in the future.

The production surveillance focus we have on our wells is significantly enhanced by our automation systems and ability to monitor and, in most cases, control gas flow over a large portion of our fields. We have a Dallas based operations control center that is manned 24 hours a day that monitors all of our Haynesville/Bossier shale wells. This robust system combined with the dedicated efforts of our Field staff and Dallas team play key roles in optimizing the daily gas flow from our assets.

East Texas and North Louisiana conventional assets

Our conventional Cotton Valley, Hosston, Travis Peak and Pettet assets were contributed to the EXCO/HGI Partnership effective February 14, 2013. The Vernon Field in Jackson Parish, Louisiana, which is the largest producing field in the EXCO/HGI Partnership, produces from the Cotton Valley and Bossier Sand formations at depths ranging from 12,000 to 15,000 feet. The other Cotton Valley, Hosston, Travis Peak and Pettet formation properties are located in Caddo and DeSoto Parishes, Louisiana primarily in four fields-Holly, Kingston, Caspiana, and Longwood, as well as acreage and production in Harrison, Panola, and Gregg Counties in Texas, primarily across three fields - Carthage, Waskom and Danville. These producing zones range in depth from 7,800 feet to 11,000 feet. Due to the current depressed natural gas prices, the EXCO/HGI Partnership does not have any development plans in these areas beyond maintenance capital projects. The EXCO/HGI Partnership currently has a total of 915 wells flowing to sales with an average gross operated shale gas production rate of approximately 124.1 Mmcfe per day (67.0 Mmcfe per day net) from these assets.

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.

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. We currently operate a total of 5,778 vertical shallow wells flowing to sales with an average gross production rate of approximately 33.0 Mmcf per day (13.5 Mmcf per day net).

Our Pennsylvania area encompasses 17 counties. Drilling, completion and production activities target the Marcellus shale as well as the Upper Devonian, Venanago, Bradford and Elk sandstone groups at depths ranging from 1,800 to more than 8,000 feet. We plan to drill 5 gross operated Marcellus shale appraisal wells in the Pennsylvania area during 2013.

Our West Virginia area includes 27 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.

The emergence of the Marcellus shale play over the last several years resulted in a shift of our focus from the traditional shallow development to exploration and development of the Marcellus shale. We currently hold approximately 311,800 net acres in the Appalachian Basin, with approximately 128,100 of these net acres prospective for the Marcellus shale.

Marcellus shale

Our 2012 development program was a combination of appraisal and development wells in Northeast Pennsylvania, which includes Sullivan and Lycoming Counties and our Central Pennsylvania area which includes mainly Armstrong and Jefferson Counties.

The Northeast Pennsylvania area was acquired from Chief Oil and Gas LLC in early 2011. Our position, which totals approximately 28,000 net acres, established a core area where we quickly moved into manufacturing mode by drilling, then completing multi-wells on a pad. The development wells in Northeast Pennsylvania have initial production rates ranging from 2.5 to 11.8 Mmcf per day from lateral lengths varying from 2,950 to 4,900 feet. We currently have a total of 64 horizontal wells flowing to sales with an average gross production rate of approximately 120 Mmcf per day (27.3 Mmcf per day net). During 2012, we drilled and completed 31 gross (8.2 net) wells.

In our Central Pennsylvania area, we have mainly drilled appraisal wells and conducted spacing tests. A significant amount of data has been collected and is being used to formulate a development plan based on the preliminary performance results in each area. During 2012, we drilled and completed 7 gross (3.3 net) wells. The wells in Central Pennsylvania had initial production rates ranging from 3.0 to 8.8 Mmcf per day from lateral lengths varying from 3,250 to 4,900 feet. We currently have a total of 29 horizontal wells flowing to sales with an average gross production rate of approximately 37.4 Mmcf per day (15.7 Mmcf per day net).

Marcellus shale operational effectiveness

We continue to build our core positions in Central and Northeast Pennsylvania. Concurrently, capital will be focused in these areas, particularly where we realized strong results in 2012, have significant acreage, and have market access that is either existing or currently under construction. We have a significant amount of held-by-production acreage. Of the Marcellus shale acreage that is not held-by-production, approximately 16.0%, or 20,179 net acres of 128,100 total net acres are scheduled to expire in 2013.

We realized strong cost performance in 2012. Drilling costs were down 46% in the second half of 2012 and completion costs were down 11% in the fourth quarter of 2012. We also realized operating cost reductions of 39% to $0.73 per Mcfe in 2012. Cost benefits are being realized from engineering design improvements, operational efficiencies, more developed infrastructure and focused supply chain processes.

We currently have one horizontal drilling rig operating in the basin. The 2013 drilling plan primarily entails appraisal in the Northeast Pennsylvania area. We plan to drill 5 gross (1.5 net) operated appraisal wells.

Permian Basin

Our conventional shallow assets in the Permian Basin were contributed to the EXCO/HGI Partnership effective February 14, 2013. 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. The activities of the EXCO/HGI Partnership will be focused on conventional oil and natural gas properties. Prolific reservoirs with potential for multi-pay horizons will be targeted using 3-D seismic. The properties are characterized by long reserve lives and low operating costs. The EXCO/HGI Partnership will evaluate acquisition opportunities in this region.

Sugg Ranch Field

The Sugg Ranch Field is located primarily in Irion County, Texas. The EXCO/HGI Partnership owns a 96.7% interest in the property. As of December 31, 2012, Proved Reserves were 4,363 Mbbl of oil, 6,613 Mbbl of NGLs and 30,049 Mmcf of natural gas with 422 gross producing wells. Production is primarily from the Canyon Sand from depths of 6,700 to 7,900 feet. At year end, production was approximately 3,600 barrels per day of net oil equivalents which consisted of 1,400 net barrels of oil, 5,700 net Mcf of natural gas and 1,270 net barrels of NGLs per day. The Sugg Ranch properties contain significant amounts of oil and NGLs. The shallow rights in the Sugg Ranch Field were contributed to the EXCO/HGI Partnership. The EXCO/HGI Partnership expects to run one operated rig and drill and complete 36 gross (34.9 net) wells at Sugg Ranch in 2013. EXCO retained the deep rights and is evaluating those deeper zones for horizontal drilling opportunities.

Our hydraulic fracturing activities

Oil and natural gas may be recovered from our properties through the use of sophisticated drilling and hydraulic fracturing techniques. Hydraulic fracturing involves the injection of water, sand, gel and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Our hydraulic fracturing activities are primarily focused in our shale plays in East Texas, North Louisiana, Pennsylvania and West Virginia.

As of December 31, 2012, we had approximately 58,400 net acres in our East Texas/North Louisiana region for the Haynesville and Bossier shale formations and 128,100 net acres in our Appalachia region for the Marcellus shale formation, all of which are subject to hydraulic fracturing operations. As of December 31, 2012, a total of 762.1 Bcfe of our Proved Reserves were located in our East Texas/North Louisiana operating area, of which 454.4 Bcfe of Proved Reserves were associated with our Haynesville and Bossier shale properties. As of December 31, 2012, a total of 149.9 Bcfe of our Proved Reserves were located in our Appalachia operating area, of which 99.4 Bcfe of Proved Reserves were associated with our Marcellus shale properties.

Although the cost of each well will vary, on average approximately 20-25% of the total cost of drilling and completing a well in the Haynesville and Bossier shale formation and approximately 35-40% of the total cost of drilling and completing a well in the Marcellus shale formation is associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completing our wells are treated and are built into our capital expenditure budget.

We review best practices and industry standards and strive to comply with all regulatory requirements in the protection of potable water sources when drilling and completing our wells. Protective practices include, but are not limited to, setting multiple strings of protection pipe across potable water sources and cementing these pipe strings to surface, continuously monitoring the hydraulic fracturing process in real time and disposing of non-recycled produced fluids in authorized disposal wells at depths below the potable water sources. In addition, we actively seek methods to minimize the environmental impact of our hydraulic fracturing operations in all of our operating areas. For example, we use discharge water from a local paper plant as a key water source for our fracture stimulation operations in North Louisiana. In addition, we recycle flowback fluids when economically feasible.

For more information on the risks of hydraulic fracturing, please read “Item 1A. Risk Factors-Our business exposes us to liability and extensive regulation on environmental matters, which could result in substantial expenditures” and “Item 1A. Risk Factors-Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.”

Our oil and natural gas reserves

Our Proved Reserves as of December 31, 2012 were approximately 1.0 Tcfe, of which approximately 54.9% were shale. Our Haynesville/Bossier shale Proved Reserves represented 82.0% of our total shale Proved Reserves as the Marcellus shale reserves are in their early stages of development. Our non-shale Proved Reserves represented approximately 45.1% of total Proved Reserves as of December 31, 2012, over half of which were in the Vernon Field in Jackson Parish, Louisiana, which was contributed to the EXCO/HGI Partnership on February 14, 2013.

Upon formation of the EXCO/HGI Partnership, approximately 90.0% (404.8 Bcfe) of our non-shale Proved Reserves as of December 31, 2012, were contributed to the EXCO/HGI Partnership. The properties contributed to the EXCO/HGI Partnership consisted of our existing Cotton Valley assets in the Holly, Waskom, Danville and Vernon fields in East Texas and North Louisiana. All depths from the base of the Cotton Valley and above were included. In addition, all of our rights (excluding all depths below the base of the Canyon Sand intervals) in our Canyon Sand field in Irion and Tom Green Counties, Texas and certain other West Texas conventional properties were also contributed. We own an economic interest of 25.5% in the EXCO/HGI Partnership.

Our shale assets are in various stages of appraisal and development from full manufacturing development phase in DeSoto Parish to testing of spacing units in the Shelby area. In the Marcellus shale, our activities have ranged from the development/delineation phase in Northeast Pennsylvania to testing of spacing patterns in other areas of Pennsylvania. We are currently drilling appraisal wells as we have suspended Appalachia development drilling. Typically, it will take several years to move into manufacturing mode. Consequently, costs and Proved Reserve additions will cycle from higher costs and lower Proved Reserves additions to lower costs and higher Proved Reserves additions. Initially, higher costs are incurred because of the traditional learning curve improvements of drilling and completion, which are refined in each area. Proved Reserves can increase from improvement in the drilling and completion techniques, but more importantly, as production trends and reservoir data becomes available, “reasonable certainty” increases. This can result in anomalous annual Reserve Life and finding and development metrics. Tight gas or shale plays typically have Reserve Lives that exceed 10 years unless the play is emerging and there is not enough data to support higher Proved Reserves. Even though we have been developing DeSoto Parish for approximately four years, Reserve Lives are presently computing in the five year range. Our Marcellus shale developments and Shelby Area are less mature than DeSoto Parish. Therefore, our Reserve Lives are negatively impacted as we are in the early stages of development in these types of reservoirs.

We had two fields that exceeded 15% of our total Proved Reserves as of December 31, 2012. Our Haynesville shale field represented approximately 44.2% and the Vernon field represented approximately 24.6% of our total Proved Reserves. Please see “Our production, prices and expenses” for additional information regarding production from the Haynesville shale fields and the Vernon field. On February 14, 2013, the Vernon field was contributed to the EXCO/HGI Partnership.

The following table summarizes Proved Reserves as of December 31, 2012, 2011, and 2010. This information was prepared in accordance with the rules and regulations of the SEC.

	As of December 31,		
	2012	**2011**	**2010**
Oil (Mbbls)			
Developed	4,371	4,565	4,633
Undeveloped	1,199	1,789	2,725
Total	5,570	6,354	7,358
Natural Gas Liquids (Mbbls) (1)			
Developed	4,784	—	—
Undeveloped	1,855	—	—
Total	6,639	—	—
Natural Gas (Mmcf)			
Developed	917,326	955,522	793,777
Undeveloped	18,806	335,942	661,176
Total	936,132	1,291,464	1,454,953
Equivalent reserves (Mmcfe)			
Developed	972,256	982,912	821,575
Undeveloped	37,130	346,676	667,526
Total	1,009,386	1,329,588	1,489,101
PV-10 (in millions) (2)			
Developed	$ 666.0	$ 1,545.7	$ 1,187.2
Undeveloped	30.1	128.0	169.3
Total	$ 696.1	$ 1,673.7	$ 1,356.5
Standardized Measure (in millions) (3)	$ 696.1	$ 1,426.5	$ 1,223.4

(1) Beginning in 2012, we began reporting our NGLs separately. In 2011 and 2010, the NGLs were reported as a component of natural gas.

(2) The PV-10 is based on the following average spot prices, in each case adjusted for historical differentials. Prices presented on the table below are the trailing 12 month simple average spot price at the first of the month for natural gas at Henry Hub and West Texas Intermediate crude oil at Cushing, Oklahoma. Our NGLs price was computed using the average of realized prices in 2012.

	Average spot prices					
	Natural gas (per Mmbtu)		Oil (per Bbl)		Natural gas liquid (per Bbl)	
December 31, 2012	$	2.76	$	94.71	$	46.57
December 31, 2011		4.12		96.19		—
December 31, 2010		4.38		79.43		—

(3) There is no difference in Standardized Measure and PV-10 for the year ended December 31, 2012 as the impacts of lower natural gas prices, net cash flows and net operating loss carry-forwards eliminated future income taxes.

We believe that PV-10, 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 as of December 31, 2012, 2011 and 2010:

	As of December 31,					
(in millions)	2012		2011		2010	
PV-10	$	696.1	$	1,673.7	$	1,356.5
Future income taxes		—		(390.8)		(305.1)
Discount of future income taxes at 10% per annum		—		143.6		172.0
Standardized Measure	$	696.1	$	1,426.5	$	1,223.4

Changes in our Proved Reserves for the year ended December 31, 2012 were impacted by significant declines in the price of natural gas, which resulted in elimination of estimated future income taxes and reduced drilling programs in our shale operations. In addition, the low natural gas price resulted in deferral and reclassifications of Proved Undeveloped Reserve locations beyond a five year scheduling criteria. For the year ended December 31, 2012, only our Permian area, which contains significant oil and NGLs, and certain areas of Northeastern Pennsylvania, had economical Proved Undeveloped Reserve locations when using prices prescribed by the SEC.

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 NSAI, in connection with the preparation of estimates of our Proved Reserves. Our Vice President of Engineering is a registered Professional Engineer with over 30 years of experience in the oil and natural gas industry and has served in various leadership roles with the Gas Research Institute, the Society of Petroleum Engineers and the Society of Women Engineers. She is a graduate of Pennsylvania State University 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 annually 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 flows for our non-shale properties as of December 31, 2012, 2011 and 2010 have been prepared by Lee Keeling. Our estimated Proved Reserves and future net cash flows for our shale properties as of December 31, 2012, were prepared by NSAI. Our estimated Proved Reserves and future net cash flows for our shale properties as of December 31, 2011 and 2010 were prepared by Haas Petroleum Engineering Services, Inc. Lee Keeling, Haas Petroleum Engineering Services, Inc. and NSAI 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 and NSAI have performed these services for over 50 years. 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 Proved Reserves will ultimately be realized. Our actual results could differ materially. See “Note 21. 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 the Standardized Measure.

Lee Keeling and NSAI 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 NSAI 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 anything came to the attention of Lee Keeling or NSAI which brought into question the validity or sufficiency of any such information or data, Lee Keeling or NSAI 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 NSAI 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 our estimate of Proved Reserves as of December 31, 2012 and changes in our Proved Reserves during 2012. This discussion and analysis should be read in conjunction with “Note 21. Supplemental information relating to oil and natural gas producing activities (unaudited)” and in “Item 1A. 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 changes in our Proved Reserves from January 1, 2012 to December 31, 2012.

	Oil (Mbbls)	Natural gas (Mmcf)	Natural gas liquids (Mbbls)	Equivalent natural gas (Mmcfe)
Proved Developed Reserves	4,371	917,326	4,784	972,256
Proved Undeveloped Reserves	1,199	18,806	1,855	37,130
Total Proved Reserves	5,570	936,132	6,639	1,009,386
The changes in reserves for the year are as follows:				
January 1, 2012	6,354	1,291,464	—	1,329,588
Purchase of reserves in place	—	—	—	—
Discoveries and extensions	492	96,615	424	102,111
Revisions of previous estimates:				
Reclassification to unproved reserves (1)	(437)	(6,114)	—	(8,736)
Changes in price	(110)	(466,238)	—	(466,898)
Other factors	(26)	205,898	6,724	246,086
Sales of reserves in place	—	(2,837)	—	(2,837)
Production	(703)	(182,656)	(509)	(189,928)
December 31, 2012	5,570	936,132	6,639	1,009,386

(1) Represents Proved Undeveloped Reserves reclassified to unproved pursuant to the five year development rule established by the SEC. This reclassification was a result of decisions not to commit development capital in the current commodity price environment. While these locations previously qualified as Proved Undeveloped Reserves as they directly offset a proved location, our planned capital programs do not support development at this time.

Current year oil and natural gas production

Total oil and natural gas production in 2012 was 189.9 Bcfe, which included approximately 10.3 Bcfe in production from extensions and discoveries in 2012 that were not reflected in our Proved Reserves at January 1, 2012.

New discoveries and extensions

Proved Reserves additions from discoveries and extensions in 2012 were 102.1 Bcfe. Of this total, 25.6 Bcfe were in Haynesville/Bossier shale plays in DeSoto Parish, Louisiana and the Shelby area. The Marcellus shale accounted for 59.5 Bcf of the total additions while the remaining 17.0 Bcfe was in the Permian Basin.

Revisions of previous estimates

In addition to 8.7 Bcfe of Proved Reserves that were reclassified to an unproved category due to scheduling, downward revisions of Proved Reserves due to depressed prices were 466.9 Bcfe in 2012, of which 62.7% were associated with the proved undeveloped locations in the Haynesville shale. Net upward revisions due to other factors were 246.1 Bcfe, which reflect a reduction in operating expenses, capital costs and improvement in operating practices. Of the upward revisions due to other factors, 56.6% were in the Haynesville shale where we continue to have increased Proved Reserves due to longer production histories.

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, 2012:

	Mmcfe
Proved Undeveloped Reserves at January 1, 2012	346,676
Purchases of Proved Undeveloped reserves in place	—
New discoveries and extensions (1)	19,388
Proved Undeveloped Reserves transferred to developed (2)	(124,598)
Proved Undeveloped Reserves transferred to unproved (3)	(8,736)
Other revisions of previous estimates of Proved Undeveloped Reserves (4)	(195,600)
Proved Undeveloped Reserves at December 31, 2012	37,130

(1) Approximately 53.9% and 46.1% of the discoveries and extensions of Proved Undeveloped Reserves in 2012 occurred in our Appalachia region Marcellus shale play and in our Permian region Canyon Sand play, respectively.
(2) Proved Undeveloped Reserves transferred to Proved Developed Reserves in 2012 were primarily in DeSoto Parish. Capital costs incurred to convert Proved Undeveloped Reserves to Proved Developed Reserves were $246.6 million, excluding carried in development costs incurred in 2011.
(3) Represents Proved Undeveloped Reserves reclassified to unproved pursuant to the five year development rule established by the SEC. This reclassification was a result of decisions not to commit development capital in the current commodity price environment. While these locations qualify as Proved Undeveloped Reserves as they directly offset a proved location, our planned capital programs do not support development at this time.
(4) The downward revisions are due primarily to depressed natural gas prices.

Impacts of changes in reserves on depletion rate and statements of operations in 2012

Our depletion rate decreased to $1.52 per Mcfe in 2012 from $1.87 per Mcfe in 2011. The rate per Mcfe was most significantly affected by ceiling test write-downs of $1.3 billion during 2012.

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.

(in thousands, except production and per unit amounts)	As of December 31, 2012	2011	2010
Revenues, production and prices:			
Oil:			
Revenue (1)	$ 62,119	$ 67,440	$ 52,411
Production sold (Mbbl)	704	741	688
Average sales price per Bbl (1)	$ 88.24	$ 91.01	$ 76.18
Natural Gas Liquids:			
Revenue (1)	$ 22,068	$ 29,639	$ 20,245
Production sold (Mbbl)	510	505	441
Average sales price per Bbl (1)	$ 43.27	$ 58.69	$ 45.91
Natural Gas:			
Revenue (1)	$ 462,422	$ 657,122	$ 442,570
Production sold (Mmcf)	182,644	176,700	107,438
Average sales price per Mcf (1)	$ 2.53	$ 3.72	$ 4.12
Cost and Expenses:			
Average production cost per Mcfe (excluding severance and ad valorem taxes)	$ 0.41	$ 0.46	$ 0.74
General and administrative expenses per Mcfe	$ 0.44	$ 0.57	$ 0.92
Depreciation, depletion and amortization per Mcfe	$ 1.60	$ 1.97	$ 1.72

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

The following table provides additional information related to our Vernon field and Haynesville shale, each of which exceeded 15% of our total Proved Reserves as of December 31, 2012, 2011 and 2010.

	As of December 31, 2012	2011	2010
Vernon Field:			
Oil production sold (Mbbls)	10	15	5
Natural gas production sold (Mmcf)	18,972	22,228	27,122
Average price per Bbl	$ 93.77	$ 91.51	$ 78.68
Average price per Mcf	$ 2.64	$ 3.90	$ 4.31
Average production cost per Mcfe (excluding severance and ad valorem taxes)	$ 0.94	$ 1.12	$ 1.06
Haynesville Shale:			
Natural gas production sold (Mmcf)	136,910	130,028	55,298
Average price per Mcf	$ 2.47	$ 3.64	$ 3.96
Average production cost per Mcfe (excluding severance and ad valorem taxes)	$ 0.12	$ 0.08	$ 0.09

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, 2012					
	Gross wells (1)			Net wells		
Areas	**Oil**	**Natural gas**	**Total**	**Oil**	**Natural gas**	**Total**
East Texas/North Louisiana	53	1,529	1,582	25.5	730.4	755.9
Appalachia	325	5,810	6,135	158.6	2,629.7	2,788.3
Permian and other	390	72	462	368.9	51.8	420.7
Total	768	7,411	8,179	553.0	3,411.9	3,964.9

(1) As of December 31, 2012, we held interests in 10 gross wells with multiple completions.

As of December 31, 2012, we were the operator of 7,616 gross (3,899.9 net) wells, which represented approximately 95.7% of our proved developed producing reserves.

Our drilling activities

Since 2009, we have been 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 during the period, regardless of when drilling was initiated. At December 31, 2012, we had 5 gross (2.0 net) wells being drilled and 35 gross (11.9 net) wells being completed or awaiting completion.

	Development wells					
	Gross			Net		
	Productive	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2012 (1)	169	2	171	73.8	1.9	75.7
Year ended December 31, 2011	255	2	257	116.9	1.9	118.8
Year ended December 31, 2010	171	—	171	83.4	—	83.4

	Exploratory wells					
	Gross			Net		
	Productive	**Dry**	**Total**	**Productive**	**Dry**	**Total**
Year ended December 31, 2012 (2)	6	—	6	2.2	—	2.2
Year ended December 31, 2011	80	2	82	26.9	2.0	28.9
Year ended December 31, 2010	34	2	36	13.8	2.0	15.8

(1) Our 2012 Haynesville and Bossier drilling in DeSoto Parish and Southern Caddo Parish, Louisiana, the Shelby area in Texas and the Marcellus wells in Armstrong and Lycoming Counties in Pennsylvania are classified as development.
(2) Our exploratory wells include Marcellus wells in Jefferson and Sullivan Counties, Pennsylvania.

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, 2012			
	Developed		Undeveloped	
Area	Gross	Net	Gross	Net
East Texas/North Louisiana	203,825	104,144	31,162	15,412
Appalachia	374,064	169,361	353,398	142,449
Permian and other	30,718	28,075	18,902	18,637
Total	608,607	301,580	403,462	176,498

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 29,233, 6,904 and 19,275 net acres with leases expiring in 2013, 2014 and 2015, respectively. Approximately 76.4% of the scheduled expiring acreage is located within our shale resource plays.

The 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.

Equity investments

Midstream operations

EXCO and BG Group each own a 50% interest in TGGT and the Appalachia Midstream JV, which provide midstream services to natural gas producers. We use the equity method of accounting for these investments and they are treated as a business segment for financial reporting purposes. See “Note 14. Segment information” in our notes to consolidated financial statements for additional details regarding our midstream business segment.

TGGT's operations are principally designed to facilitate the 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. TGGT's primary customers are EXCO and BG Group.

TGGT operates amine, glycol, and H2S treating facilities, which treat natural gas to meet pipeline specifications for downstream transportation. TGGT's system, which has access to 17 interstate and intrastate pipeline markets, has approximately 128 miles of pipeline comprised of 12, 16, and 20-inch diameter pipe in its Legacy East Texas area and 27 miles of pipeline comprised of 36-inch diameter pipe in the North Louisiana area.

TGGT completed major midstream expansion efforts in 2012 in the Shelby Area, which has approximately 115 miles of operational pipeline comprised of 4-inch to 36-inch diameter pipe servicing Haynesville/Bossier producers.

TGGT owns and operates a network of gas gathering systems comprised of approximately 790 miles of pipeline located in East Texas and North Louisiana as of December 31, 2012. These gathering pipelines primarily service Cotton Valley production in East Texas/North Louisiana and Haynesville/Bossier production in North Louisiana. Approximately 290 miles of TGGT'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.

Our Appalachia Midstream JV's focus is to maximize take-away from existing infrastructure as the Marcellus shale region develops. While certain infrastructure projects have been installed, the Appalachia Midstream JV's operations are minimal as the majority of our development drilling activities are in an area where third party infrastructure is utilized.

Appalachia JV

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.

Our principal customers

In 2012, sales to BG Energy Merchants LLC accounted for approximately 36.0% of total consolidated revenues. BG Energy Merchants LLC is a subsidiary of BG Group. 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 acquiring 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 substantially greater financial, managerial, technological and other resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and natural gas, but also have refining operations, market refined products and their own drilling rigs and oilfield services.

The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which have delayed development drilling and other exploitation activities and have caused significant price increases and operational delays. 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, supply or demand imbalances occur or how these market-driven factors impact prices, which affects our development and exploitation programs. Competition also exists for hiring experienced personnel, particularly in petroleum engineering, geoscience, accounting and financial reporting, tax and land professions. In addition, the market for oil and natural gas producing properties is competitive. We are often outbid by competitors in our attempts to acquire properties. The oil and natural gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal. 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 financial sanctions for noncompliance. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, we believe these burdens 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 the federal, state and local levels. These regulations require, among other things, permits for the drilling of wells, drilling bonds and reports concerning operations. Many states, counties and municipalities in which we operate also regulate one or more of the following:

- the location of wells;

- the method of drilling, completion and operating wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- notice to surface owners and other third parties; and
- produced water and waste disposal.

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 and generally prohibit the venting or flaring of natural gas and require that oil and natural gas be produced 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, most states generally impose a production, ad valorem or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction. Many local authorities also impose an ad valorem tax on the minerals in place. 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 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 transportation of oil and natural gas, 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 that apply to the exploration and production of oil and natural gas are often reviewed, amended, expanded and reinterpreted, making the prediction of future costs or the impact of regulatory compliance to new laws and statutes difficult. The regulatory burden on the oil and natural gas industry increases its cost of doing business and, consequently, adversely affects its profitability.

FERC matters

The availability, terms and cost of downstream transportation significantly affect sales of natural gas, oil and NGLs. 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, FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural 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 natural gas market participants other than intrastate pipelines. 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 and the Dodd Frank Wall Street Reform and Consumer Protection Act of 2010, or the Dodd Frank 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, Bureau of Ocean Energy Management, Bureau of Safety and Environmental Enforcement or other appropriate federal, state or tribal agencies.

Surface Damage Acts

In addition, a number of states and some tribal nations have enacted surface damage statutes, or 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 surface 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 U.S. 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, or the Pipeline Safety Act, 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 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 DOT Pipeline and Hazardous Materials Safety Administration, 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.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law on January 3, 2012. This bill includes a number of provisions affecting pipeline owners and operators that became effective upon approval, including increased civil penalties for violators of pipeline regulations and additional reporting requirements. Most of the changes do not impact natural gas gathering lines. The legislation requires the PHMSA to issue or revise certain regulations and to conduct various reviews, studies and evaluations. In addition, the PHMSA in August 2011 issued an Advance Notice of Proposed Rulemaking regarding pipeline safety. As described in the notice, PHMSA is considering regulations regarding, among other things, the designation of additional high consequence areas along pipelines, minimum requirements for leak detection systems, installation of emergency flow restricting devices, and revision of valve spacing requirements.

U.S. federal taxation

The federal government may adopt tax laws and/or regulations that will possibly materially adversely affect us. Some possible measures that have been proposed in the past include the repeal or elimination of percentage depletion and the immediate deduction or write-offs of intangible drilling costs. Because of the speculative nature of such measures at this time, 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 of 1972, or CWA;
- the Rivers and Harbors Act of 1899;
- the Comprehensive Environmental Response, Compensation and Liability Act, as amended, 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, as well as injunctive relief, may be imposed for non-compliance with environmental laws and regulations. Additionally, these laws and regulations may 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 discharges of pollutants as well as certain discharges of dredged or fill material into waters of the United States, including certain wetlands 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 may require permitting 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, often referred to as Superfund, and comparable state 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 cannot ensure 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

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.

RCRA and comparable state and local programs impose requirements on the management, generation, treatment, storage, disposal and remediation of both hazardous and nonhazardous solid wastes. Although we believe we utilize operating and waste disposal practices that are standard in the industry, 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; these wastes may not be exempt under current applicable state statutes.

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 or for more streamlined permitting, for example, through qualifications for permits by rule, standard permits 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 may 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.

On April 17, 2012, the EPA issued final rules to subject oil and natural gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce volatile organic compound, or VOC, emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to new hydraulically fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, which became effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules may require changes to our operations, including the installation of new equipment to control emissions. We are currently evaluating the effect these rules will have on our business.

We are unable to assure 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, the 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, the EPA published its so-called GHG tailoring rule that will phase in federal prevention of significant deterioration, or 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, the 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. EXCO submitted its first annual report for 2011 in September 2012. Although this rule does not limit the amount of GHGs that can be emitted, it requires us to incur costs to monitor, recordkeep and report GHG emissions associated with our operations. In addition, some states have considered, and notably California has adopted, a state specific GHG regulatory program that may limit GHG emissions or may require costs in association with the control of GHG emissions.

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. Many states, including, 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.

Nearly all of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and natural gas wells. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Our hydraulic fracturing activities are focused in our shale plays in East Texas, North Louisiana, Pennsylvania and West Virginia. Many of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well.

The SDWA currently exempts from regulation the injection of fluids or propping agents (other than diesel fuels) for hydraulic fracturing operations. Congress has periodically considered legislation to amend the federal SDWA to remove the exemption from regulation and permitting that is applicable to hydraulic fracturing operations and to require reporting and disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Sponsors of bills previously introduced before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. These bills, or similar legislation, 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, the EPA has recently been taking action to assert federal regulatory authority over hydraulic fracturing using diesel under the SDWA's Underground Injection Control Program. Further, in March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. In December 2012, the EPA issued a progress report on its hydraulic fracturing study with final results expected in 2014. In addition, in December 2011, the EPA published an unrelated draft report concluding that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming. This study remains subject to review. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and enforcement initiative could result in additional regulatory scrutiny or further legislative or regulatory action regarding hydraulic fracturing or similar production operations that could make it difficult to perform hydraulic fracturing and increase our costs of compliance or significantly impact our business, results of operations, cash flows, financial position and future growth.

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. 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; and
- minimum depth of hydraulic fracturing.

Local regulations, which may be preempted by state and federal regulations, have included the following which may extend to all operations including those beyond hydraulic fracturing:

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

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.

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.

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.

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 state requirements.

Title to our properties

When we acquire developed properties we conduct a title investigation, which will most often include either reviewing or obtaining a title opinion. 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 will 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 marketable 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 materially detract from the value of our properties or materially interfere with property used in the operation of our business. In addition to the foregoing listed burdens, substantially all of our properties are pledged as collateral under the EXCO Resources Credit Agreement.

Operational factors and insurance

Oil and natural gas exploration and development involves a high degree of risk. In the event of exploration failures, environmental damage, or other accidents such as well fires, blowouts, equipment failure and 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 the loss of oil and natural gas properties. As is common in the oil and natural gas industry, we are not fully insured 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 - We are exposed to operating hazards and uninsured risks that could adversely impact our results of operations and cash flows.”

We currently carry general liability insurance and excess liability insurance with a combined annual limit of $101 million per occurrence and in the aggregate. These insurance policies contain maximum policy limits and deductibles ranging from $1,000 to $50,000 that must be met prior to recovery, and are subject to customary exclusions and limitations. Our general liability insurance covers us and our subsidiaries for third-party claims and liabilities arising out of lease operations and related activities. The excess liability insurance is in addition to, and is triggered if, the general liability insurance per occurrence limit is reached.

We also maintain control of well insurance and pollution insurance. Our control of well insurance has per occurrence and combined single limits ranging from $3 million to $20 million and is subject to a $500,000 deductible per occurrence. Our pollution insurance has a per occurrence and aggregate annual limit of $30 million and is subject to a $25,000 deductible per occurrence.

We require our third-party contractors to sign master service agreements in which they generally agree to indemnify us for the injury and death of the service provider's employees as well as contractors and subcontractors that are hired by the service provider. Similarly, we agree to indemnify our third-party contractors against claims made by our employees and our other contractors. Additionally, each party generally is responsible for damage to its own property.

Our third-party contractors that perform hydraulic fracturing operations for us sign master service agreements containing the indemnification provisions noted above. We do not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. We believe that our general liability, excess liability and pollution insurance policies would cover third-party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies. However, these policies may not cover fines, penalties or costs and expenses related to government-mandated environmental clean-up responsibilities.

Our employees

As of December 31, 2012, we employed 919 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 satisfactory. 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, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, 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,” variations of such words 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;
- the availability of foreign oil and natural gas, including liquefied natural gas;
- future capital requirements and availability of financing;
- disruption of credit and capital markets and the ability of financial institutions to honor their commitments;
- estimates of reserves and economic assumptions;

- 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;
- political and economic conditions and events 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;
- 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 securities.

Our revenues, operating results and financial condition depend substantially on prevailing prices for oil and natural gas and the availability of capital from our credit agreement. Declines in oil or natural gas prices may have a material adverse effect on our financial condition, liquidity, results of operations, the amount of oil or natural gas that we can produce economically and the ability fund our operations. 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 depicts the subsurface strata in two dimensions.

3-D seismic. Geophysical data that depicts 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.

Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an “analogous reservoir” refers to a reservoir that shares the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) the same environment of deposition; (iii) a similar geological structure; and (iv) the same drive mechanism.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil, NGLs 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. This ratio of Bbl to Mcf is commonly used in the oil and natural gas industry and represents the approximate energy equivalent of natural gas to oil or NGLs, and does not represent the sales price equivalency of natural gas to oil or NGLs. Currently the sales price of a Bbl or NGL is significantly higher than the sales price of six Mcf of natural gas.

Boepd. Barrels of oil equivalent per day.

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 to the appropriate authority that the well has been abandoned.

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 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 in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial petroleum deposit. An exploratory well may be drilled either (a) in search of a new and as yet undiscovered pool (of oil or natural gas) or (b) with the hope of greatly extending the limits of a pool that is already developed. These types of wells may also be referred to as appraisal or delineation wells.

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, natural 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 natural 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. This ratio of Bbl to Mcf is commonly used in the oil and natural gas industry and represents the approximate energy equivalent of natural gas to oil or NGLs, and does not represent the sales price equivalency of natural gas to oil or NGLs. Currently the sales price of a Bbl or NGL is significantly higher than the sales price of 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. Exists when the sum of fractional ownership interests owned in gross acres or gross wells equals one.

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 the 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 natural 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 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.

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. These 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 if the extraction is by means not involving a well.

Proved Reserves. Those quantities of oil and natural 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 natural 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 to classify a reserve as proved, 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 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.

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 reservoirs.

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 the costs of production.

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

Shut-in well. A producing well that has been closed down temporarily for, among other things, economics, cleaning out, building up pressure, lack of a market or lack of equipment.

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 are estimated by applying the simple average of the 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 price differentials, to the estimated future production of year-end Proved Reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end 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. This ratio of Bbl to Mcf is commonly used in the oil and natural gas industry and represents the approximate energy equivalent of natural gas to oil or NGLs, and does not represent the sales price equivalency of natural gas to oil or NGLs. Currently the sales price of a Bbl or NGL is significantly higher than the sales price of six Mcf of natural gas.

Undeveloped acreage. Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or 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 available, free of charge, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to these reports on our website at *www.excoresources.com* as soon as reasonably practicable after those reports and other information is 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

Natural gas prices have declined substantially since 2011, and are expected to remain depressed for the foreseeable future. Sustained depressed natural gas prices will adversely affect our assets, development plans, results of operations and financial position.

The NYMEX price for natural gas has declined from a high of $4.85 per Mmbtu during 2011 to a low of $1.91 per Mmbtu during 2012. As of December 31, 2012, 92.7% of our Proved Reserves were natural gas and approximately 96.2% of our production was natural gas. The reduction in prices has been caused by many factors, including increases in natural gas production from nonconventional (shale) reserves, warmer than normal temperatures and high levels of natural gas in storage. We have derivative financial instruments in place at prices higher than those that are currently prevailing. However, if prices for natural gas remain depressed for a substantial period of time, we may be required to write-down the value of our oil and natural gas properties further or revise our development plans, which may cause certain of our undeveloped well locations to no longer be considered proved and certain of our leases to expire as they may be uneconomical to develop. If prices remain depressed, our ability to maintain compliance with certain covenants in the EXCO Resources Credit Agreement and the credit agreements within our joint ventures and partnerships, may be negatively affected. In addition, sustained depressed natural gas prices will reduce the amounts we would otherwise have available to pay expenses and service our debt obligations.

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, 2012, 92.7% of our Proved Reserves were natural gas and approximately 96.2% of our production was 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:

- supply and demand for oil and natural gas and expectations regarding supply and demand;
- 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;
- regional price differentials and quality differentials of oil and natural gas;
- the availability of refining capacity;
- technological advances affecting oil and natural gas production and consumption;
- weather conditions and natural disasters;
- foreign and domestic government relations; and
- overall economic conditions.

In the past, prices of natural gas and oil have been extremely volatile, and we expect this volatility to continue. During 2012, the NYMEX price for natural gas has fluctuated from a high of $3.90 per Mmbtu to a low of $1.91 per Mmbtu, and the NYMEX West Texas Intermediate crude oil price ranged from a high of $109.77 per Bbl to a low of $77.69 per Bbl. For the five years ended December 31, 2012, the NYMEX Henry Hub natural gas price ranged from a high of $13.58 per Mmbtu to a low of $1.91 per Mmbtu, 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, 2012, the spot market price for natural gas at Henry Hub was $3.35 per Mmbtu, a 10.6% increase from December 31, 2011. On December 31, 2012, the spot market price for crude oil at Cushing was $91.82 per Bbl, a 7.1% decrease from December 31, 2011. For 2012, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were $88.24 per Bbl and $2.53 per Mcf compared with average realized prices of $91.01 per Bbl and $3.72 per Mcf for 2011.

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 reflects 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, which result in increased costs to drill wells. All of these risks could adversely affect our results of operations and financial condition.

Our drilling results in new or emerging shale resource plays 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 have focused on developing our Haynesville/Bossier and Marcellus shale areas, we now invest significant capital to drill and properly develop the acreage in these shale areas. We may use bank debt to fund these development plans but we do not receive credit for borrowing base purposes until the wells we drill 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 natural gas.

The Haynesville/Bossier shale wells we have drilled to date have generally reported very high initial production rates. 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. Our failure to 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 HGI, 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 partners 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 certain 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 our investment in the joint venture; and
- our joint venture partners may decide to terminate their relationship with us in any joint venture company or sell their interest in any of these companies and we may be unable to replace such joint venture partner or raise the necessary financing to purchase such joint venture partner's interest.

The failure to continue some of our joint ventures or to resolve disagreements with our joint venture 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.

We are a party to the East Texas/North Louisiana JV and TGGT with BG Group. The East Texas/North Louisiana JV operates as a joint venture pursuant to a joint development agreement under which EXCO acts as the operator. TGGT 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.

We are also party to the Appalachia JV with BG Group. Pursuant to the agreements governing the Appalachia JV, 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 and BG Group are party to the Appalachia Midstream JV through which they will pursue the construction and expansion of gathering systems, pipeline systems and treating facilities for anticipated future production from the Marcellus shale. EXCO has unconditionally guaranteed its subsidiaries' performance of the joint venture agreements under the Appalachia joint ventures.

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.

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 us 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

Consolidated Statements 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 securities. During the years ended December 31, 2012 and 2011, we received cash payments to settle our derivative financial instrument contracts totaling $202.1 million and $135.4 million, respectively. For the year ended December 31, 2012, 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 $83.5 million. As of December 31, 2012, the net unrealized gains on our oil and natural gas derivative financial instrument contracts were $37.3 million. The ultimate settlement amount of these unrealized derivative financial instrument contracts is dependent on future commodity prices. 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, 2012, our consolidated indebtedness was approximately $1.9 billion. Following the formation of the EXCO/HGI Partnership, our consolidated debt was reduced to $1.3 billion. However, future cash flows from our interest in the EXCO/HGI Partnership will be significantly reduced. While we believe our consolidated debt is manageable, our reserves, borrowing base, production and cash flows can be negatively impacted by the declines in natural gas prices. In addition, our ratio of consolidated funded indebtedness to consolidated EBITDAX, as defined in the EXCO Resources Credit Agreement, is computed using a trailing twelve-month computation. As a result, our ability to maintain compliance with this covenant may be negatively affected when oil and/or natural gas prices decline for an extended period of time. 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. 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 from operations and capital resources may be insufficient for payment of interest on, and principal of, our debt under the EXCO Resources Credit Agreement and the 2018 Notes, which could cause us to default on our obligations and could impair our liquidity.

While we do not guarantee the debt of the EXCO/HGI Partnership, their ability to manage their debt may impact their ability to grow the partnership and fund distributions to us and HGI.

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 the EXCO Resources Credit Agreement will also decline. We may be unable to locate additional reserves, drill economically productive wells or acquire properties containing Proved Reserves.

Development and exploration drilling and strategic acquisitions are the main methods of replacing reserves. However, development and exploration drilling operations may not result in any increases in reserves for various reasons. Our future oil and natural gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our level of production and cash flows will be adversely affected.

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, we cannot feasibly review in detail every individual property involved in an acquisition. Any future acquisitions will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards and liabilities, potential tax and Employee Retirement Income 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.

Our acquisition, exploration, exploitation, development and production businesses require substantial capital expenditures. We finance our capital expenditures primarily through our cash flow from operations, partnership structures, debt and capital markets, when conditions are favorable. We expect that lower oil and natural gas prices, combined with a reduced drilling program, will reduce our cash flow in 2013. The weakness and volatility in domestic and global financial markets and economic conditions in recent years may affect our ability to obtain equity or debt financing on terms we consider acceptable, if at all. In addition, a substantial increase in interest rates would decrease our net cash flows available for reinvestment. Any of these factors could have a material and adverse effect on our business, financial condition and results of operations if we lose opportunities to acquire oil and natural gas properties and businesses as part of our growth strategy.

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. At times, we have experienced production curtailments in East Texas/North Louisiana resulting from capacity restraints, offsetting fracturing stimulation operations and short term shutdowns of certain pipelines for maintenance purposes. As we have increased our knowledge of the Haynesville/Bossier shale plays, 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 common 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 results 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 may be unable to integrate successfully the operations of acquisitions with our operations and we may not realize all the anticipated benefits of any acquisitions.

Integration of our acquisitions with our business and operations has been a complex, time consuming and costly process. Failure to successfully assimilate our past or future acquisitions could adversely affect our financial condition and results of operations.

Our acquisitions involve numerous risks, including:

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- the loss of significant key employees from the acquired business:
- the diversion of management's attention from other business concerns;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

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 Reserves and the PV-10 and Standardized Measure. 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 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, the amount of 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 and values 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, natural 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.

Our operations may be interrupted by severe weather or drilling restrictions.

Our operations are conducted primarily in East Texas, Northern Louisiana, Appalachia and the Permian Basin in West Texas. The weather in these areas can be extreme and can cause interruption in our exploration and production operations. Severe weather can result in damage to our facilities entailing longer operational interruptions and significant capital investment. Likewise, our operations are subject to disruption from hurricanes, winter storms and severe cold, which can limit operations involving fluids and impair access to our facilities. Additionally, many municipalities in Appalachia impose weight restrictions on the paved roads that lead to our jobsites due to the conditions caused by spring thaws.

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

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

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

Legislation has been proposed by the federal government on numerous occasions that, if enacted into law, would 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 natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

The EPA's implementation of climate change regulations could result in increased operating costs and reduced demand for our oil and natural gas production.

Although federal legislation regarding the control of emissions of greenhouse gases or GHGs, for the present, appears unlikely, the EPA has been implementing regulatory measures under existing its 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 the 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 our oil and natural gas production.

On June 3, 2010, the 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, the EPA published a rule establishing GHG reporting requirements for sources in the oil and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions. EXCO submitted its first annual report for 2011 in September 2012. Each subsequent report is due in March of the following year. Although this rule does not limit the amount of GHGs that can be emitted, it requires us to incur costs to monitor, record and report GHG emissions associated with our operations.

The adoption of derivatives legislation and regulations thereunder could have an adverse impact on our ability to hedge risks associated with our business and could affect our business, financial condition or results of operations.

On July 21, 2010, the President signed into law the Dodd-Frank Act, which, among other things, establishes federal oversight and regulation of the over-the-counter derivative market and entities that participate in the market and requires the CFTC and the SEC to implement the new law by enacting regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the over-the-counter market.

In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions); the CFTC's final rule was set aside by the U.S. District Court for the District of Columbia on September 28, 2012 and remanded to the CFTC to resolve ambiguity as to whether statutory requirements for such limits to be determined necessary and appropriate were satisfied. As a result, the rule has not yet taken effect, although the CFTC has indicated that it intends to appeal the court's decision and that it believes the Dodd-Frank Act requires it to impose position limits. The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions.

In addition, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirement to use cleared exchanges, rather than hedging over-the-counter, and the requirements to post margin in connection with hedging activities. While it is not possible at this time to predict when the CFTC will finalize certain other related rules and regulations, the Dodd-Frank Act and related regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although whether these requirements will apply to our business is uncertain at this time. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, our hedging would become more expensive and we may decide to alter our hedging strategy.

The financial reform legislation may also require the counterparties to derivative instruments to spin off some of their derivative activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, restrict our flexibility in conducting trading and hedging activity and increase our exposure to less creditworthy counterparties. If we reduce our use of derivative contracts as a result of the new requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our ability to hedge risks and on our business, financial position, results of operations or cash flows.

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

The SDWA currently exempts from regulation the injection of fluids or propping agents (other than diesel levels) for hydraulic fracturing operations. Congress has considered legislation to amend the federal SDWA to remove the exemption from regulation and permitting that is applicable to hydraulic fracturing operations and require reporting and disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Sponsors of bills previously introduced before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Such bills or similar legislation, 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, the EPA has recently been taking action to assert federal regulatory authority over hydraulic fracturing using diesel under the SWDA's Underground Injection Control Program. Further, in March 2010, the EPA announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. In December 2012, the EPA issued a progress report on its hydraulic fracturing study with final results expected in 2014. In addition, in December 2011, the EPA published an unrelated draft report concluding that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming. This study remains subject to further review. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. Consequently, these studies and initiatives could spur further legislative or regulatory action regarding hydraulic fracturing or similar production operations.

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 the federal CAA, or state or regional regulatory programs. Regulation of GHG emissions by the EPA, or various states in the United States in areas in which we conduct business, for example, could have an adverse effect on our operations and demand for our oil and natural gas production. Moreover, the EPA has shown a general increased scrutiny on the oil and natural gas industry through its GHG, CAA and SDWA regulations.

On April 17, 2012, the EPA issued final rules to subject oil and natural gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce VOC emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to new hydraulically fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, which became effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules may require changes to our operations, including the installation of new equipment to control emissions. We are currently evaluating the effect these rules will have on our business.

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

We are substantially dependent upon the skills of 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 on him. 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. For years ended December 31, 2012 and 2011, we recorded non-cash ceiling test write-downs of approximately $1.3 billion and $233.2 million respectively. Future 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, natural gas or NGLs.

Our ability to collect the proceeds from the sale of oil, natural gas and NGLs from our customers depends on the payment ability of our customer base, which includes several significant customers. We sell our oil, natural gas and NGLs to a variety of customers. As operator, we pay expenses and bill our non-operating partners for their share of costs. 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 2012, sales to BG Energy Merchants LLC accounted for approximately 36.0% of total consolidated revenues. BG Energy Merchants LLC is a subsidiary of BG Group. As our volumes in the Haynesville shale grow, sales to 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 that 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, 2012, we were contractually committed to spend approximately $736.0 million over the next nine years for firm transportation services. We may enter into additional firm transportation agreements as our development of our Marcellus shale plays expands. The use of firm transportation agreements allow 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. In addition, our recent reduction in drilling programs will cause natural gas production volumes to decline, which will increase the amount of unused firm transportation quantities and negatively impact 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 substantially greater financial, managerial, technological and other resources than we do. 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 expense/cost 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 also exists for 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.

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

We depend upon TGGT and third party pipelines and other facilities to provide gathering and transportation. 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. If any of such events occur, they 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.

Our business could be negatively impacted by security threats, including cybersecurity threats, and other disruptions.

As an oil and natural gas producer, we face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities, essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows. Cybersecurity attacks in particular are evolving and include but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

While we believe we have taken the steps necessary to improve the effectiveness of our internal control over financial reporting, if we are unable to successfully address or prevent material weaknesses in our internal control over financial reporting, 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.

In the past, our management has occasionally identified a material weakness in our internal control over financial reporting. For example, management identified a material weakness in internal control over financial reporting as of September 30, 2012, related to the computation of the fair value of financial instruments. As a result of this material weakness, our management concluded that, as of September 30, 2012, we did not maintain effective disclosure controls and procedures or internal control over financial reporting. 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 annual or interim financial statements will not be prevented or detected on a timely basis.

Although we believe we have taken the steps necessary to remediate the material weakness and improve the effectiveness of our disclosure controls and procedures and internal control over financial reporting, we can give no assurances that the measures we take will remediate any material weakness that we identify or that any additional material weaknesses will not arise in the future. We will continue to monitor the effectiveness of these and other processes, procedures and controls and will make any further changes management determines appropriate.

Any material weakness or other deficiencies in our disclosure controls and procedures and internal control over financial reporting may affect our ability to report our financial results on a timely and accurate basis and to comply with disclosure obligations or cause our financial statements to contain material misstatements, which could negatively affect the market price and trading liquidity of our common shares or cause investors to lose confidence in our reported financial information.

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

While we have taken actions designed to address compliance with the requirements of the Sarbanes-Oxley Act of 2002, as amended, and the rules and regulations thereunder, there are inherent limitations in our ability to comply with these requirements. Our management, including our Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer, does not expect that our internal control over financial reporting and disclosure controls and procedures will prevent all errors 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 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.

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 19, 2013, we had approximately \$1.3 billion of indebtedness, including \$534.2 million of indebtedness subject to variable interest rates and \$750.0 million of indebtedness under the 2018 Notes. Our total interest expense, excluding amortization of deferred financing costs, on an annual basis based on currently available interest rates would be approximately \$69.3 million and would change by approximately \$5.3 million for every 1% change in interest rates.

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

- it may be more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the EXCO Resources Credit Agreement, the indenture governing the 2018 Notes, or 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;
- when oil and natural gas prices decline, our ability to maintain compliance with our financial covenants becomes more difficult and our borrowing base is subject to reductions, which may reduce or eliminate our ability to fund our operations; 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 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 the EXCO Resources Credit Agreement. Further, failing to comply with the financial and other restrictive covenants in either of the credit agreements 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 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 or acquisition 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 the 2018 Notes and the EXCO Resources Credit Agreement, and to fund planned capital expenditures will depend on our ability to generate cash flow 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 the EXCO Resources Credit Agreement, to fund planned capital expenditures 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.

Our borrowing base under the EXCO Resources Credit Agreement is subject to semi-annual redeterminations and was reduced to $900.0 million to reflect EXCO's contribution of assets to the EXCO/HGI Partnership. If our borrowing base were to be reduced to a level which was less than the current borrowings, we would be required to reduce our borrowings to a level sufficient to cure any deficiency. We may be required to sell assets or seek alternative debt or equity which may not be available at commercially reasonable terms, if at all.

In addition, we conduct certain of our operations through our joint ventures, private partnerships and subsidiaries. Accordingly, repayment of our indebtedness, including the 2018 Notes, is dependent on the generation of cash flow by our joint ventures and subsidiaries and their ability to make such cash available to us, by dividend, debt repayment or otherwise. Unless they are guarantors of the 2018 Notes or our other indebtedness, our joint ventures and subsidiaries do not have any obligation to pay amounts due on the 2018 Notes or our other indebtedness or to make funds available for that purpose. Our joint ventures and subsidiaries may not be able to, or may not be permitted to, make distributions to enable us to make payments in respect of our indebtedness. Each joint venture and subsidiary is a distinct legal entity, and, under certain circumstances, legal and contractual restrictions may limit our ability to obtain cash from our joint ventures and subsidiaries. While the Indenture and the agreements governing certain of our other existing indebtedness limit the ability of certain of our joint ventures and subsidiaries to incur consensual restrictions on their ability to pay dividends or make other intercompany payments to us, these limitations are subject to qualifications and exceptions. In the event that we do not receive distributions from our joint ventures and subsidiaries, we may be unable to make required principal and interest payments on our indebtedness.

If we cannot make scheduled payments on our debt, we will be in default and holders of the 2018 Notes could declare all outstanding principal and interest to be due and payable, the lenders under the EXCO Resources Credit Agreement could terminate their commitments to loan money, our secured lenders could foreclose against the assets securing their borrowings and we could be forced into bankruptcy or liquidation. Our inability to generate sufficient cash flows to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms or at all, would materially and adversely affect our financial position and results of operations.

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.

The EXCO Resources 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, the EXCO Resources 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 the EXCO Resources 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 the applicable indebtedness. The consolidated funded indebtedness to consolidated EBITDAX ratio, as defined in the EXCO Resources Credit Agreement, is computed using a trailing twelve-month computation. When oil and/or natural gas prices decline for an extended period of time, our ability to comply with this covenant becomes more difficult. Such a default, if not cured or waived, may allow the creditors to accelerate the related indebtedness and could result in acceleration of any other indebtedness to which a cross-acceleration or cross-default provision applies. An event of default under the Indenture would permit the lenders under the EXCO Resources Credit Agreement to terminate all commitments to extend further credit under the agreement. Furthermore, if we were unable to repay the amounts due and payable under the EXCO Resources Credit Agreement, those lenders could proceed against the collateral granted to them to secure that indebtedness. In the event that our lenders or noteholders accelerate the repayment of our borrowings, we and our subsidiaries may not have sufficient assets to repay that indebtedness. As a result of these restrictions, we may be:

- limited in how we conduct our business;
- unable to raise additional debt or equity financing during general economic, business or industry downturns; or
- unable to compete effectively or to take advantage of new business opportunities.

The credit risk of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies and other institutions. These transactions expose us to credit risk in the event of default of our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges and insurance companies in the form of claims under our policies. In addition, if any lender under the EXCO Resources Credit Agreement is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under the credit agreement.

Risks relating to our common stock

Our stock price may fluctuate significantly.

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

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

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

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.

We currently have 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, the EXCO Resources 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; Warrendale, Pennsylvania and Cranberry Township, 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	$	332,400	December 31, 2015
Warrendale, Pennsylvania	56,000	$	112,000	October 31, 2016
Cranberry Township, Pennsylvania	6,900	$	9,500	December 31, 2014

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

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market information for our common stock

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					
	High		Low		Dividends Declared	
2012						
First Quarter	$	10.84	$	6.50	$	0.04
Second Quarter		8.25		5.65		0.04
Third Quarter		8.14		6.58		0.04
Fourth Quarter		9.08		6.71		0.04
2011						
First Quarter	$	20.79	$	18.95	$	0.04
Second Quarter		21.04		16.91		0.04
Third Quarter		17.81		10.58		0.04
Fourth Quarter		13.55		9.33		0.04

Our shareholders

According to our transfer agent, Continental Stock Transfer & Trust Company, there were 323 holders of record of our common stock on December 31, 2012 (including nominee holders such as banks and brokerage firms who hold shares for beneficial holders and the restricted stock shareholders).

Our dividend policy

In 2012, we paid cash dividends of $0.16 per share ($0.04 per quarter) totaling $34.4 million. In addition, we accrued $0.3 million of dividends payable on unvested restricted stock awards which are payable upon the vesting of these awards. 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, the indenture governing the 2018 Notes and the approval of EXCO's board of directors.

Issuer repurchases of common stock

The following table details our repurchases of common stock for the three months ended December 31, 2012:

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, 2012 - October 31, 2012	—	$ —	—	$ 192.5 million
November 1, 2012 - November 30, 2012	—	$ —	—	$ 192.5 million
December 1, 2012 - December 31, 2012	—	$ —	—	$ 192.5 million
Total	—	$ —	—	

(1) On July 19, 2010, we announced a $200.0 million share repurchase program.

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

	Years Ended December 31,				
(in thousands, except per share amounts)	2012	2011	2010	2009	2008
Statement of operations data (1):					
Revenues:					
Oil and natural gas	$ 546,609	$ 754,201	$ 515,226	$ 550,505	$ 1,404,826
Midstream (2)	—	—	—	35,330	85,432
Total revenues	546,609	754,201	515,226	585,835	1,490,258
Cost and expenses:					
Oil and natural gas production (3)	104,610	108,641	108,184	177,629	238,071
Midstream operating (2)	—	—	—	35,580	82,797
Gathering and transportation	102,875	86,881	54,877	18,960	14,206
Depreciation, depletion and amortization	303,156	362,956	196,963	221,438	460,314
Write-down of oil and natural gas properties	1,346,749	233,239	—	1,293,579	2,815,835
Accretion of discount on asset retirement obligations	3,887	3,652	3,758	7,132	6,703
General and administrative (4)	83,818	104,618	105,114	99,177	87,568
(Gain) loss on divestitures and other operating items (5)	17,029	23,819	(509,872)	(676,434)	(2,692)
Total cost and expenses	1,962,124	923,806	(40,976)	1,177,061	3,702,802
Operating income (loss)	(1,415,515)	(169,605)	556,202	(591,226)	(2,212,544)
Other income (expense):					
Interest expense	(73,492)	(61,023)	(45,533)	(147,161)	(161,638)
Gain on derivative financial instruments (6)	66,133	219,730	146,516	232,025	384,389
Other income	969	788	327	126	1,289

Equity method income (loss) (2)	28,620	32,706	16,022	(69)	—
Total other income (expense)	22,230	192,201	117,332	84,921	224,040
Income (loss) before income taxes	(1,393,285)	22,596	673,534	(506,305)	(1,988,504)
Income tax expense (benefit)	—	—	1,608	9,501	(255,033)
Net income (loss)	(1,393,285)	22,596	671,926	(496,804)	(1,733,471)
Preferred stock dividends	—	—	—	—	(76,997)
Net income (loss) available to common shareholders	$ (1,393,285)	$ 22,596	$ 671,926	$ (496,804)	$ (1,810,468)
Basic net income (loss) per share available to common shareholders	(6.50)	0.11	3.16	(2.35)	(11.81)
Diluted net income (loss) per share available to common shareholders	(6.50)	0.10	3.11	(2.35)	(11.81)
Cash dividends declared per share	0.16	0.16	0.14	0.05	—
Weighted average common and common equivalent shares outstanding:					
Basic	214,321	213,908	212,465	211,266	153,346
Diluted	214,321	216,705	215,735	211,266	153,346
Statement of cash flow data:					
Net cash provided by (used in):					
Operating activities	$ 514,786	$ 428,543	$ 339,921	$ 433,605	$ 974,966
Investing activities	(427,094)	(709,531)	(712,854)	1,235,275	(1,708,579)
Financing activities	(74,045)	268,756	348,755	(1,657,612)	735,242
Balance sheet data:					
Current assets	$ 361,866	$ 678,008	$ 520,460	$ 402,088	$ 513,040
Total assets	2,323,732	3,791,587	3,477,420	2,358,894	4,822,352
Current liabilities	237,931	287,399	285,698	212,914	322,873
Long-term debt	1,848,972	1,887,828	1,588,269	1,196,277	3,019,738
Shareholders' equity	149,393	1,558,332	1,540,552	859,588	1,332,501
Total liabilities and shareholders equity	2,323,732	3,791,587	3,477,420	2,358,894	4,822,352

(1) We have completed numerous acquisitions and dispositions which impact the comparability of the selected financial data between periods.

(2) Prior to the closing of the formation of TGGT on August 14, 2009, we designated our midstream operations as a separate business segment. Following the formation of TGGT, our midstream operations are accounted for using the equity method.

(3) Share-based compensation calculated pursuant to FASB Accounting Standards Codification 718, *Compensation-Stock Compensation*, or ASC 718, included in oil and natural gas production costs was $0.0 million, $0.1 million, $1.0 million, $2.8 million and $4.2 million for the years ended December 31, 2012, 2011, 2010, 2009 and 2008, respectively.

(4) Share-based compensation calculated pursuant to ASC 718 included in general and administrative expenses was $8.9 million, $10.9 million, $15.8 million, $16.2 million and $11.8 million for the years ended December 31, 2012, 2011, 2010, 2009 and 2008, respectively.

(5) In 2010 and 2009, we recognized gains on the sale transactions attributable to the formation of our joint ventures with BG Group.

(6) 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 in our Consolidated Statements 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 management's 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 management's 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 "Item 1A. Risk Factors" and elsewhere in this Annual Report on Form 10-K.*

Overview and history

We are an independent oil and natural gas company engaged in the acquisition, exploration, exploitation, development and production of onshore U.S. oil and natural gas properties. Our principal operations are conducted in certain key U.S. 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.

Recent developments

On February 14, 2013, we formed the EXCO/HGI Partnership. Pursuant to the agreements governing the transaction, we contributed our conventional non-shale assets in East Texas and North Louisiana and our shallow Canyon Sand and other assets in the Permian Basin of West Texas to the partnership in exchange for approximately $573.3 million of cash, after customary preliminary purchase price adjustments, and a 25.5% economic interest in the partnership. HGI owns the remaining 74.5% economic interest in the partnership. HGI contributed cash to us in the amount of approximately $348.3 million. The remaining proceeds we received were in the form of a cash distribution from the partnership of $225.0 million from a draw on the EXCO/HGI Partnership's credit agreement discussed below. The primary strategy of the EXCO/HGI Partnership will be to acquire conventional producing oil and natural gas properties to enhance asset value and cash flow.

In connection with its formation, the EXCO/HGI Partnership entered into the EXCO/HGI Partnership Credit Agreement with an initial borrowing base of $400.0 million, of which $230.0 million was drawn at closing. Borrowings under the EXCO/HGI Partnership Credit Agreement are secured by the properties contributed to the EXCO/HGI Partnership and we do not guarantee the EXCO/HGI Partnership's debt.

Proceeds from the formation of the EXCO/HGI Partnership were used to reduce outstanding borrowings under the EXCO Resources Credit Agreement. As a result of this transaction, our borrowing base under the EXCO Resources Credit Agreement was reduced to $900.0 million.

Immediately following closing, the EXCO/HGI Partnership entered into an agreement to purchase all of the shallow Cotton Valley assets within our joint venture with BG Group for $132.5 million, subject to customary closing adjustments. A deposit of $25.0 million was paid to BG Group when the agreement was executed. The transaction is expected to close in the first quarter of 2013 and will be funded with borrowings from the partnership's credit agreement.

Capital expenditures

As of December 31, 2012, our Proved Reserves were approximately 1.0 Tcfe and the related PV-10 and Standardized Measure of our Proved Reserves was approximately $696.1 million (see Item 1. Business-Summary of geographic areas of operations). For the year ended December 31, 2012, we produced 189.9 Bcfe of oil and natural gas resulting in a Reserve Life of approximately 5.3 years.

During 2012, we emphasized cost containment of operating and administrative expenses and reduction of drilling and completion costs in response to a low natural gas price environment. We reduced our operated drilling rigs in the Haynesville/ Bossier shale from 22 during the fourth quarter of 2011 to three at the end of December 2012 and ended the year with one operated drilling rig in the Marcellus shale and one operated drilling rig in our Permian area. Our capital expenditures for 2012 totaled $505.2 million, of which $381.9 million was related to our East Texas/North Louisiana and Appalachia regions. During 2012, we spent $284.8 million in East Texas/North Louisiana, $280.1 million of which was in the area of mutual interest with BG Group, or the East Texas/North Louisiana AMI. During 2012, we spent $97.1 million in Appalachia, which reflects the favorable impact of $49.4 million of the Appalachia Carry. As of December 31, 2012, the Appalachia Carry was fully utilized. Contributions to our equity investments were $14.9 million, corporate and gathering capital expenditures were $49.3 million and oil and natural gas property acquisitions were $3.3 million. These leases were mostly undeveloped acreage in the Permian Basin with horizontal drilling opportunities.

Our 2013 capital budget is $273.0 million, of which $214.0 million is allocated to development and completion activities. Management continues to address cost reduction initiatives in operating and administrative areas in response to the continuation of our reduced drilling program. Our significant held-by-production acreage and moderate derivative financial instruments allow us flexibility to manage the pace of drilling as we expect natural gas prices to remain volatile. Our capital budget, excludes any capital expenditures associated with the EXCO/HGI Partnership, as these are expected to be funded through the partnership and its credit facility.

For 2013, TGGT's capital budget is approximately $40.0 million, which is primarily associated with field infrastructure pipelines to support projected drilling activity in North Louisiana and legacy East Texas areas. The substantial reduction in capital expenditures projected in 2013 as compared to 2012 is due to the completion of all major facility projects in 2012 and a reduction in drilling activity in this service area.

We do not expect to have significant activities in our Appalachia Midstream JV as the majority of our Northeastern Pennsylvania development drilling accesses an existing third party gathering system.

Our current acquisition strategy is to focus on producing properties with upside development opportunities. While we expect to continue to evaluate acreage acquisition opportunities in our shale areas, we believe the current depressed natural gas prices provides greater opportunities from producing property acquisitions versus drilling location acquisitions.

Like all oil and natural gas production companies, we face the challenge of natural production declines. We attempt to offset this natural decline by drilling to identify and develop additional reserves and add reserves through acquisitions. As of December 31, 2012, 92.7% of our estimated Proved Reserves were natural gas. Following the formation of the EXCO/HGI Partnership, the percentage of our natural gas Proved Reserves increased to 99.0%. Consequently, our results of operations are influenced significantly by the natural gas markets. As a result of our reduced drilling program, we expect our production volumes to decline in 2013.

In the second quarter of 2012, we began reporting our NGLs production separately from our natural gas production. We have recast the estimated production volumes and NGLs for the first quarter of 2012 and all of 2011 and 2010 to conform to this presentation.

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, revenue recognition and natural gas imbalances, deferred abandonment on asset retirement obligations and accounting for 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 this 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 additional 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 the SEC's 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 or cost of capital.

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.

Business combinations

When we acquire assets that qualify as a business, we use FASB ASC 805-10, *Business Combinations*, or ASC 805-10, to record our acquisitions of oil and natural gas properties or entities which we acquired beginning on 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 manage price fluctuations, protect our investments and achieve a more predictable cash flow in connection 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 compensation in accordance with FASB ASC 718, *Compensation-Stock Compensation*, or ASC 718. At December 31, 2012, our employees and directors held options under EXCO's 2005 Long-Term Incentive Plan, or the 2005 Incentive Plan, to purchase 14,015,795 shares of EXCO's common stock at prices ranging from $6.33 per share to $38.01 per share. The options expire five to ten years from the date of grant, depending on the terms of the grant. Pursuant to the 2005 Incentive Plan, 25% of the options vest immediately with an additional 25% of the options vesting 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 2012 granted options using the Black-Scholes model ranged from $3.23 per share to $4.42 per share. As December 31, 2012, our employees also held 2,806,365 restricted shares under the 2005 Incentive Plan with grant prices ranging from $7.57 to $14.83 per share. The restricted shares vest over three to five years, depending on the terms of the grant. ASC 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 the year ended December 31, 2012 was $16.4 million, of which $7.5 million was capitalized as part of our oil and natural gas properties. For the years ended December 31, 2011 and 2010, a total of $17.4 million and $23.2 million, respectively, of share-based compensation was incurred, of which $6.4 million and $6.4 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. Our unproved property costs, which include unproved oil and natural gas properties, properties under development and major development projeccts 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.

When we acquire significant amounts of undeveloped acreage, we capitalize interest on the acquisition costs in accordance with FASB ASC 835-20, *Capitalization of Interest*. 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 less estimated salvage costs, is 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.

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 limitation is less than the full cost pool, a ceiling test write-down of oil and natural gas properties is required. 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 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, 2012, the trailing 12 month reference prices were $94.71 per Bbl of oil for West Texas Intermediate at Cushing, Oklahoma and $2.76 per Mmbtu for natural gas at Henry Hub. and $46.57 per Bbl for NGLs based on the twelve month average of realized prices in 2012. Each of the aforementioned reference prices for oil, natural gas and NGLs were 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.

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 revisions of such estimate. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered.

Goodwill

In accordance with FASB ASC 350-20, *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 31st of each year. Losses, if any, resulting from impairment tests will be reflected in operating income in the Consolidated Statements of Operations.

To determine the fair value of our exploration and production reporting unit, a two-part, equally weighted approach is applied. We perform an income approach, which uses a discounted cash flow model to value our business, and a market approach, in which our value is determined using trading metrics and transaction multiples of peer companies.

As a result of testing, the fair value of the business exceeded the carrying value of net assets and we did not record an impairment charge for the periods ending December 31, 2012, 2011 or 2010.

The properties we sold to BG Group in 2010 to create the Appalachia JV 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 when computing our gains on those transactions.

The balance of goodwill as of December 31, 2012 and 2011 was $218.3 million.

Revenue recognition and natural gas imbalances

We use the sales method of accounting for oil and natural gas revenues. Under the sales method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers. Gas imbalances at December 31, 2012, 2011 and 2010 were not significant.

Deferred abandonment on asset retirement obligations

We follow FASB ASC 410-20, *Asset Retirement Obligations,* or ASC 401-20, 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 in accordance FASB ASC 740, *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.

Our results of operations

A summary of key financial data for the years ended December 31, 2012, 2011 and 2010 related to our results of operations is presented below:

	Years Ended December 31,			Year to year change	
(dollars in thousands, except per unit prices)	2012	2011	2010	2012-2011	2011-2010
Production:					
Oil (Mbbls)	704	741	688	(37)	53
Natural gas liquids (Mbbls)	510	505	441	5	64
Natural gas (Mmcf)	182,644	176,700	107,438	5,944	69,262
Total production (Mmcfe) (1)	189,928	184,176	114,212	5,752	69,964
Average daily production (Mmcfe)	519	505	313	14	192
Revenues before derivative financial instrument activities:					
Oil	$ 62,119	$ 67,440	$ 52,411	$ (5,321)	15,029
Natural gas liquids	22,068	29,639	20,245	(7,571)	9,394
Natural gas	462,422	657,122	442,570	(194,700)	214,552
Total revenue	$ 546,609	$ 754,201	$ 515,226	$ (207,592)	238,975
Oil and natural gas derivative financial instruments:					
Cash settlements (payments) on derivative financial instruments	$ 202,078	$ 135,417	$ 217,455	$ 66,661	$ (82,038)
Non-cash change in fair value of derivative financial instruments	(135,945)	84,313	(70,939)	(220,258)	155,252
Total derivative financial instrument activities	$ 66,133	$ 219,730	$ 146,516	$ (153,597)	$ 73,214
Average sales price (before cash settlements of derivative financial instruments):					
Oil (per Bbl)	$ 88.24	$ 91.01	$ 76.18	$ (2.77)	$ 14.83
Natural gas liquids (per Bbl)	43.27	58.69	45.91	(15.42)	12.78
Natural gas (per Mcf)	2.53	3.72	4.12	(1.19)	(0.40)
Natural gas equivalent (per Mcfe)	2.88	4.10	4.51	(1.22)	(0.41)
Costs and expenses:					
Oil and natural gas operating costs (2)	$ 77,127	$ 84,766	$ 84,145	$ (7,639)	$ 621
Production and ad valorem taxes	27,483	23,875	24,039	3,608	(164)
Gathering and transportation	102,875	86,881	54,877	15,994	32,004
Depletion	288,401	344,947	179,613	(56,546)	165,334
Depreciation and amortization	14,755	18,009	17,350	(3,254)	659
General and administrative (3)	83,818	104,618	105,114	(20,800)	(496)
Interest expense	73,492	61,023	45,533	12,469	15,490
Costs and expenses (per Mcfe):					
Oil and natural gas operating costs	$ 0.41	$ 0.46	$ 0.74	$ (0.05)	$ (0.28)
Production and ad valorem taxes	0.14	0.13	0.21	0.01	(0.08)
Gathering and transportation	0.54	0.47	0.48	0.07	(0.01)
Depletion	1.52	1.87	1.57	(0.35)	0.30
Depreciation and amortization	0.08	0.10	0.15	(0.02)	(0.05)
General and administrative	0.44	0.57	0.92	(0.13)	(0.35)
Net income (loss)	$ (1,393,285)	$ 22,596	$ 671,926	$ (1,415,881)	$ (649,330)

(1) Mmcfe is calculated by converting one barrel of oil or NGLs into six Mcf of natural gas.
(2) For the year ended December 31, 2012, no share-based compensation expense was recognized in oil and natural gas operating costs. Share-based compensation expense included in oil and natural gas operating costs was $0.1 million and $1.0 million for the years ended December 31, 2011 and 2010, respectively.
(3) Share-based compensation expense included in general and administrative expenses was $8.9 million, $10.9 million, and $15.8 million for the years ended December 31, 2012, 2011 and 2010, respectively.

The following is a discussion of our financial condition and results of operations for the years ended December 31, 2012, 2011 and 2010.

The comparability of our results of operations for 2012, 2011 and 2010 was affected by:

- fluctuations in oil, natural gas prices and NGLs, which impact our oil and natural gas reserves, revenues, cash flows and net income or loss;
- ceiling test write-downs in 2012 and 2011;
- the Chief transaction, the Appalachia transaction and the Haynesville shale acquisition in 2011;
- costs associated with the former acquisition proposal, asset impairments and other non-recurring costs;
- the formation of the Appalachia JV in 2010;
- gains on sale of assets in 2010;
- mark-to-market gains and losses from our derivative financial instruments;
- changes in Proved Reserves and production volumes and their impact on depletion;
- the impact of our natural gas production volumes from our horizontal drilling activities in the Haynesville/Bossier and Marcellus shales; and
- significant changes in the amount of our long-term debt.

Due to the formation of the private partnership with HGI, our 2013 activity will be impacted by the 74.5% reduction in our ownership of the properties contributed to the EXCO/HGI Partnership.

General

The availability of a ready market for oil, natural gas and NGLs and the prices of oil, natural gas and NGLs 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;
- the domestic oversupply of natural gas;
- the inability to export domestic oil and natural gas;
- the level of domestic and industrial demand for natural gas for utilities and manufacturing operations;
- the available capacity at natural gas storage facilities and quantities of inventories in storage;
- 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 exploration, 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

We produce oil and natural gas. We do not refine or process the oil, natural gas or NGLs 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. Some of our natural gas is sold under contracts which provide for sharing in a percentage of proceeds of NGLs extracted by third party plants.

We may be unable to market all of the oil, natural gas or NGLs we produce. If our oil and natural gas can be marketed, we may be unable to negotiate favorable pricing 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. If this occurs, companies purchasing oil, natural gas or NGLs in these areas may 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 oil or natural gas reserves, we may shut in our oil or natural gas wells for certain 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. Economic conditions, particularly depressed natural gas prices, may negatively impact the liquidity and creditworthiness of our purchasers and 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, 2012, 2011 and 2010, we reported a net loss of $1.4 billion, and net income of $22.6 million and $671.9 million, respectively. The net loss for 2012 was primarily the result of non-cash ceiling test write-downs of $1.3 billion and a $207.6 million decline in revenue, both of which were the result of significant declines in natural gas prices in 2012.

Average natural gas equivalent prices for the year ended December 31, 2012 were $2.88 per Mcfe, compared with an average natural gas equivalent price of $4.10 per Mcfe for 2011. Average prices for oil and NGLs also declined in 2012 from 2011 by $2.77 per barrel and $15.42 per barrel, respectively.

The results of operations for 2011, as compared to 2010, were significantly impacted by higher production volumes, predominantly in the Haynesville/Bossier shale. In addition, our shale operations have lower operating expenses compared to our lower-volume conventional vertical wells, resulting in lower per unit operating expense. The higher production and resulting revenues were offset by lower natural gas prices and an increase in depletion. The 2011 operating results were impacted by a non-cash ceiling test write-down of $233.2 million in the fourth quarter of 2011 as a result of the continual decline in natural gas prices. Results of operations in 2010 were impacted by a gain of $528.9 million arising from the formation of the Appalachia JV.

We use oil and natural gas swap and call option contracts to mitigate fluctuations in oil and natural gas prices. We do not designate our derivative financial instruments as hedges. As a result, we mark non-cash changes in the fair value of unsettled derivative financial instruments to market at the end of each reporting period and recognize the change in our results of operations. The impacts of realized and unrealized changes in the fair value of derivative financial instruments resulted in gains of $66.1 million, $219.7 million and $146.5 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Production, revenues, and prices

The following table presents our production, revenue and average sales prices by major producing areas for the years ended December 31, 2012 and 2011:

(in thousands, except per unit rate)	Years Ended December 31, 2012 Production (Mfce)	2012 Revenue	2012 $/Mcfe	2011 Production (Mcfe)	2011 Revenue	2011 $/Mcfe	Year to year change Production (Mcfe)	Year to year change Revenue	Year to year change $/Mcfe
Producing region:									
East Texas/North Louisiana	164,779	$ 420,579	$ 2.55	162,693	$ 608,218	$ 3.74	2,086	$ (187,639)	$ (1.19)
Appalachia	16,153	47,379	2.93	12,408	52,319	4.22	3,745	(4,940)	(1.29)
Permian and other	8,996	78,651	8.74	9,075	93,664	10.32	(79)	(15,013)	(1.58)
Total	189,928	$ 546,609	$ 2.88	184,176	$ 754,201	$ 4.10	5,752	$ (207,592)	$ (1.22)

Production in our East Texas/North Louisiana region for the year ended December 31, 2012 increased by 2.1 Bcfe from the comparable period in the prior year. This increase is the result of the continued development of our East Texas/North Louisiana JV during 2011 and 2012. The increase in the East Texas/North Louisiana JV production was partially offset by normal production declines of 4.8 Bcfe in our Vernon Field and other shallow conventional wells in the region. The production profile in 2012 for Haynesville shale operations reflected increased volumes during the first half of 2012, which was attributable to a large inventory of carried in completions from the 22 rig drilling program in 2011. During the last half of 2012, our Haynesville production volumes began decreasing as the drilling activity and completions inventory declined. We expect further production declines from the Haynesville shale in 2013. The increase in Appalachia area is the result of the horizontal drilling program in the Marcellus shale. We also continued our development in the Permian Basin with one drilling rig in 2012 resulting in production remaining relatively flat compared to 2011.

For the year ended December 31, 2012, oil and natural gas revenues were $546.6 million, a 27.5% decrease from the oil and natural gas revenues of $754.2 million for the year ended December 31, 2011. The decrease in revenues is primarily a result of declines in the realized prices of oil, natural gas and NGLs, which were partially offset by increases in production. The average sales price of oil per Bbl, excluding the impact of derivative financial instruments, decreased 3.0% to $88.24 per Bbl for the year ended December 31, 2012 from $91.01 per Bbl for the year ended December 31, 2011. The average sales price of NGLs per Bbl decreased 26.3% to $43.27 per Bbl for the year ended December 31, 2012 from $58.69 per Bbl for the year ended December 31, 2011. Our average natural gas sales price, excluding the impact of derivative financial instruments, was $2.53 per Mcf for the year ended December 31, 2012 as compared to $3.72 per Mcf for the year ended December 31, 2011, a decrease of 32.0%

Our production volumes in shale operations are impacted by curtailed volumes of natural gas due to operational requirements associated with fracture stimulation and other operations on nearby horizontal wells, seasonal supply and demand conditions from end users and general maintenance and repairs to our wells. While these curtailed volumes are typically for short periods of time, they may have impacts to our revenues, cash flows and results of operations. We currently estimate that approximately 4% to 7% of our Haynesville/Bossier shale production will be curtailed during 2013.

The formation of the EXCO/HGI Partnership in February 2013 will further reduce our production volumes and revenues from our non-shale conventional properties in East Texas, North Louisiana and the Permian Basin as the EXCO/HGI Partnership transaction resulted in a sale of a 74.5% economic interest in these properties.

The following table and discussion presents our production, revenue and average sales prices by our geographic producing areas for the years ended December 31, 2011 and 2010:

(in thousands, except per unit rate)	Years Ended December 31, 2011 Production (Mcfe)	2011 Revenue	2011 $/Mcfe	2010 Production (Mcfe)	2010 Revenue	2010 $/Mcfe	Year to year change Production (Mcfe)	Year to year change Revenue	Year to year change $/Mcfe
Producing region:									
East Texas/North Louisiana	162,693	$ 608,218	$ 3.74	95,423	$ 397,680	$ 4.17	67,270	$ 210,538	$ (0.43)
Appalachia	12,408	52,319	4.22	9,427	45,962	4.88	2,981	6,357	(0.66)
Permian and other	9,075	93,664	10.32	9,362	71,584	7.65	(287)	22,080	2.67
Total	184,176	$ 754,201	$ 4.10	114,212	$ 515,226	$ 4.51	69,964	$ 238,975	$ (0.41)

Production in our East Texas/North Louisiana region in 2011 increased by 67.3 Bcfe from 2010. This increase was the result of the development of our Haynesville shale, which resulted in production increases of 74.7 Bcfe from 2010. The increase in Haynesville production was partially offset by production declines of 4.8 Bcfe in our Vernon field and 2.6 Bcfe in shallow Cotton Valley wells. The declines in the Vernon field and Cotton Valley areas were the result of the suspension of vertical drilling operations and normal production declines. Development drilling in our Appalachia region also resulted in production increases in the Marcellus shale.

Total oil and natural gas revenues in 2011 were $754.2 million compared with $515.2 million in 2010. For 2011, natural gas represented 87.1% of our oil and natural gas revenues, compared to 2010, where natural gas represented 85.9% of our oil and natural gas revenues. The 46.4% increase in total revenues in 2011 compared to 2010 was primarily a result of increased production and oil prices which were partially offset by lower natural gas prices. The average sales price of oil per Bbl, excluding the impact of derivative financial instruments, increased from $76.18 per Bbl in 2010 to $91.01 per Bbl in 2011, or 19.5%. The average natural gas sales price, excluding the impact of derivative financial instruments, was $3.72 per Mcf for 2011, a decrease of 9.7% as compared to $4.12 per Mcf for 2010. The average NGL price, excluding the impact of derivative financial instruments was $58.69 per Bbl for 2011, an increase of 27.8% compared with $45.91 per Bbl for 2010.

The prices received for our oil and natural gas production 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 year ended December 31, 2012 average production levels remain constant for the remainder of the year, a change in the average sales price of $0.10 per Mcf of natural gas sold would result in an increase or decrease in revenues and cash flows of approximately $18.3 million, a change in the average sales price of $1.00 per Bbl of NGLs would result in an increase or decrease of revenues and cash flows of approximately $0.5 million and a change in the average sales price of $1.00 per Bbl of oil sold would result in an increase or decrease in revenues and cash flow of approximately $0.7 million, without considering the effects of derivative financial instruments.

Oil and natural gas operating costs

Our oil and natural gas operating costs for the years ended December 31, 2012, 2011 and 2010 were $77.1 million, $84.8 million and $84.1 million, respectively. The decrease in total oil and natural gas operating expenses for 2012 as compared to 2011 was primarily due to the implementation of cost saving initiatives throughout our organization. Total oil and natural gas operating expenses in 2011 compared to 2010 did not increase significantly, despite an increase of over 61.3% in production volumes. This is due to horizontal wells having significantly higher production volumes with operating costs that are similar to conventional wells.

Management believes that analysis of oil and natural gas operating costs on a per Mcfe basis provides a more meaningful measure than a comparison on the basis of total costs for each period. As shown in the tables below, on a per Mcfe basis, oil and natural gas operating costs for 2012 decreased by $0.05 per Mcfe from 2011. The net decrease in both our East Texas/North Louisiana and Appalachia regions was primarily due to the combination of increased production in 2012 and implementation of numerous cost savings initiatives, including shutting in marginal producing wells with high-cost water production, decreasing compression expenditures and modifying our chemical treating programs. The Permian Basin operating expenses per Mcfe increased due to higher field maintenance and general service costs associated with liquids production in 2012.

	Years Ended December 31,								
	2012			2011			Year to year 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	$ 39,897	$ 9,497	$ 49,394	$ 46,915	$ 10,282	$ 57,197	$ (7,018)	$ (785)	$ (7,803)
Appalachia	14,882	—	14,882	15,733	—	15,733	(851)	—	(851)
Permian and other	12,539	312	12,851	11,491	345	11,836	1,048	(33)	1,015
Total	$ 67,318	$ 9,809	$ 77,127	$ 74,139	$ 10,627	$ 84,766	$ (6,821)	$ (818)	$ (7,639)

	Years Ended December 31,								
	2012			2011			Year to year 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	$ 0.24	$ 0.06	$ 0.30	$ 0.29	$ 0.06	$ 0.35	$ (0.05)	$ —	$ (0.05)
Appalachia	0.92	—	0.92	1.27	—	1.27	(0.35)	—	(0.35)
Permian and other	1.39	0.03	1.42	1.27	0.04	1.31	0.12	(0.01)	0.11
Consolidated	$ 0.36	$ 0.05	$ 0.41	$ 0.40	$ 0.06	$ 0.46	$ (0.04)	$ (0.01)	$ (0.05)

As shown in the tables below, oil and natural gas operating costs for 2011 decreased $0.28 per Mcfe from 2010. In East Texas/North Louisiana, the $0.26 per Mcfe decrease is the result of the addition of Haynesville horizontal wells and related production volumes, where we have continued to develop cost efficiencies as we have increased production. Our conventional Vernon field and Cotton Valley properties have experienced offsetting increases in operating costs on a per Mcfe basis due to decreases in production resulting from suspension of drilling activities, reduced workover activity and resulting production declines, which tend to increase operating costs on a per Mcfe basis. Decreases in Appalachia are primarily a result of increased production in the Marcellus shale, which also has a lower lease operating costs per Mcfe than the shallow wells. The Permian Basin operating costs per Mcfe increased due to higher field maintenance and general service costs associated with oil production.

	Years Ended December 31,								
	2011			2010			Year to year 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	$ 46,915	$ 10,282	$ 57,197	$ 48,255	$ 10,735	$ 58,990	$ (1,340)	$ (453)	$ (1,793)
Appalachia	15,733	—	15,733	14,929	216	15,145	804	(216)	588
Permian and other	11,491	345	11,836	9,127	883	10,010	2,364	(538)	1,826
Total	$ 74,139	$ 10,627	$ 84,766	$ 72,311	$ 11,834	$ 84,145	$ 1,828	$ (1,207)	$ 621

	Years Ended December 31,								
	2011			2010			Year to year 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	$ 0.29	$ 0.06	$ 0.35	$ 0.50	$ 0.11	$ 0.61	$ (0.21)	$ (0.05)	$ (0.26)
Appalachia	1.27	—	1.27	1.58	0.02	1.60	(0.31)	(0.02)	(0.33)
Permian and other	1.27	0.04	1.31	0.97	0.09	1.06	0.30	(0.05)	0.25
Consolidated	$ 0.40	$ 0.06	$ 0.46	$ 0.64	$ 0.10	$ 0.74	$ (0.24)	$ (0.04)	$ (0.28)

Midstream operations

We own a 50% equity interest in TGGT and the Appalachia Midstream JV, which provide midstream services to our joint ventures and natural gas producers. Our midstream operations earn fees from the gathering, treating and compression of natural gas. Additional operating margins are derived from the purchase and resale of natural gas from third parties. Our midstream joint ventures do not own any natural gas processing facilities. We use the equity method of accounting for both of our midstream joint ventures.

TGGT holds most of our East Texas/North Louisiana midstream assets. TGGT's operations are principally designed to facilitate the delivery of natural gas produced in the East Texas/North Louisiana region to market. TGGT's primary customers are EXCO and BG Group. The assets of TGGT include treating facilities and gathering pipelines that connect to downstream pipelines.

TGGT operates amine, glycol, and H2S treating facilities, which treat natural gas to meet pipeline specifications for downstream transportation. TGGT's system, which has access to 17 interstate and intrastate pipeline markets, has approximately 128 miles of pipeline comprised of 12, 16, and 20-inch diameter pipe in the East Texas area and 27 miles of pipeline comprised of 36-inch diameter pipe in the North Louisiana area. The system in the Shelby area has approximately 115 miles of operational pipeline comprised of 4-inch to 36-inch diameter pipe servicing Haynesville/Bossier producers.

TGGT owns and operates a network of gas gathering systems comprised of approximately 790 miles of pipeline located in East Texas and North Louisiana as of December 31, 2012. These gathering pipelines primarily service Cotton Valley production in East Texas/North Louisiana and Haynesville/Bossier production in North Louisiana. Approximately 290 miles of TGGT'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.

During 2012, TGGT recognized asset impairments totaling approximately $50.8 million (a net reduction of $25.4 million to our equity income) as a result of costs associated with restoration of infrastructure facilities in Red River Parish, Louisiana and certain abandonments of capital projects arising from reduced upstream drilling programs. While throughput in

2012 was comparable to 2011, we expect throughput to decline in 2013 due to normal production declines and reduced drilling activity in the Haynesville shale.

The Appalachia Midstream JV continues to operate gathering systems and compression facilities to support our production in the Appalachia JV.

Gathering and transportation

We report gathering and transportation costs in accordance with FASB ASC 605-45, *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 net-back 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 $102.9 million, or $0.54 per Mcfe, for the year ended December 31, 2012, as compared to $86.9 million, or $0.47 per Mcfe for the year ended December 31, 2011 and $54.9 million, or $0.48 per Mcfe for the year ended December 31, 2010. The increase in total gathering and transportation expense on a per Mcfe rate is a result of increased unused firm transportation volumes. We expect the unused firm transportation volumes to increase during 2013 as production declines.

We have entered into firm transportation agreements with pipeline companies to facilitate sales of our Haynesville production and report these firm transportation costs as a component of gathering and transportation expenses. At the end of 2012, our firm transportation agreements covered an average of 811 Mmcf per day through 2015, with average minimum gathering and transportation expenses of approximately $92.6 million per year. For the years 2016 through 2021, our firm transportation agreements range from covering an average of 738 Mmcf per day in 2016 and trend down to 400 Mmcf per day in 2021, with average annual minimum gathering and transportation expenses ranging from approximately $89.5 million per year in 2016 and trending down to $48.9 million in 2021.

Production and ad valorem taxes

Production and ad valorem taxes were $27.5 million, $23.9 million and $24.0 million for 2012, 2011, and 2010, respectively. On a percentage of revenue basis, before the impact of derivative financial instruments, production and ad valorem taxes were 5.0% of oil and natural gas revenues for 2012, as compared to 3.2% and 4.7% for 2011 and 2010, respectively.

In our East Texas/North Louisiana area, we currently receive severance tax holidays on certain Haynesville shale wells which reduce the effective rate of these taxes. Wells that do not have a severance tax holiday are currently taxed at a severance tax rate of $0.148 per Mcf. During 2011 and the last half of 2010, the wells that did not have a severance tax holiday were taxed at $0.164 per Mcf. Wells in the first half of 2010 were taxed at $0.33 per Mcf.

In February 2012, the Commonwealth of Pennsylvania enacted a comprehensive reform to Pennsylvania's Oil and Gas Act, or the Act, which requires an impact fee to be paid on all unconventional wells spud. The fees range from $190,000 to $355,000 per well, based on a price tier calculation to be paid annually for up to 15 years. The fee is payable for all wells spud in a single year by April 1st of the following year. The Act contains a retroactive fee to be assessed on all unconventional wells spud prior to December 31, 2011. Our retroactive fee of $2.0 million was paid in September 2012, and recorded in (Gain) loss on divestitures and other operating items on our Consolidated Statement of Operations for the year ended December 31, 2012. The estimated on-going fee, which is recorded in Production and ad valorem taxes on the Consolidated Statement of Operations, is computed using the prior year's trailing 12 month NYMEX natural gas price based on a tiered pricing system and will be paid annually for 15 years. For the year ended December 31, 2012, we recorded $1.8 million as our estimated 2012 impact fees.

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, particularly Texas, production taxes are based on a fixed percentage of gross value of products sold. While severance tax holidays are available in Texas as our production increases, our realized severance and ad valorem tax rates may become more sensitive to prices.

Overall, our production and ad valorem tax rates per Mcfe were $0.14 per Mcfe for 2012, $0.13 per Mcfe for 2011 and $0.21 per Mcfe for 2010. The following table presents our severance and ad valorem taxes on a per Mcfe basis and percentage of revenue basis for our significant producing regions.

	Years Ended December 31,								
	2012			2011			2010		
(in thousands, except per unit rate)	Production and ad valorem taxes	% of revenue	Taxes $/ Mcfe	Production and ad valorem taxes	% of revenue	Taxes $/ Mcfe	Production and ad valorem taxes	% of revenue	Taxes $/ Mcfe
Producing region:									
East Texas/North Louisiana	$ 17,501	4.2%	$ 0.11	$ 14,851	2.4%	$ 0.09	$ 16,914	4.3%	$ 0.18
Appalachia	3,013	6.4%	0.19	1,694	3.2%	0.14	1,740	3.8%	0.18
Permian and other	6,969	8.9%	0.77	7,330	7.8%	0.81	5,385	7.5%	0.58
Total	$ 27,483	5.0%	$ 0.14	$ 23,875	3.2%	$ 0.13	$ 24,039	4.7%	$ 0.21

Depletion, depreciation and amortization

The following table presents our depletion, depreciation and amortization expenses for the years ended December 31, 2012, 2011 and 2010. The depletion, depreciation 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 depletion, depreciation and amortization rate for the year ended December 31, 2012 was $1.60 per Mcfe, a $0.37 decrease from the year ended December 31, 2011. The decrease is primarily the result of ceiling test write-downs, which have lowered our depletable base. The depreciation, depletion and amortization rate for the year ended December 31, 2011 was $1.97 per Mcfe, a $0.25 increase from the year ended December 31, 2010. The increase was primarily the result of increased capital expenditures which reflect the utilization of BG Group's carried drilling costs in the East Texas/North Louisiana JV.

We expect the depletion rate in 2013 to be impacted by the ceiling test write-downs that occurred in 2012, any future write-downs and the formation of the EXCO/HGI Partnership.

	Years Ended December 31,		
(in thousands, except per unit rate)	2012	2011	2010
Depletion, depreciation and amortization:			
Depletion expense	$ 288,401	$ 344,947	$ 179,613
Depreciation and amortization expense	$ 14,755	$ 18,009	$ 17,350
Depletion per Mcfe	$ 1.52	$ 1.87	$ 1.57
Depreciation and amortization per Mcfe	$ 0.08	$ 0.10	$ 0.15
Consolidated depletion, depreciation and amortization per Mcfe	$ 1.60	$ 1.97	$ 1.72

Accretion of discount on asset retirement obligations was $3.9 million, $3.7 million and $3.8 million in 2012, 2011 and 2010, respectively.

Write-down of oil and natural gas properties

For the years ended December 31, 2012 and 2011, we recognized pre-tax ceiling test write-downs of $1.3 billion, and $233.2 million, respectively, due to the significant decline in natural gas prices. There were no ceiling test write-downs in 2010. Unless the natural gas prices for 2013 increase above the prices of 2012, we may incur additional quarterly ceiling test write-downs.

General and administrative

The following table presents our general and administrative expenses for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,			Year to year change	
(in thousands, except per unit rate)	**2012**	**2011**	**2010**	**2012-2011**	**2011-2010**
General and administrative costs:					
Gross general and administrative expense	$ 152,057	$ 175,030	$ 164,603	$ (22,973)	$ 10,427
Technical services and service agreement charges	(25,242)	(29,061)	(23,519)	3,819	(5,542)
Operator overhead reimbursements	(20,544)	(18,407)	(16,176)	(2,137)	(2,231)
Capitalized salaries and share-based compensation	(22,453)	(22,944)	(19,794)	491	(3,150)
General and administrative expense	$ 83,818	$ 104,618	$ 105,114	$ (20,800)	$ (496)
General and administrative expense per Mcfe	$ 0.44	$ 0.57	$ 0.92	$ (0.13)	$ (0.35)

Net general and administrative costs for 2012 were $83.8 million, or $0.44 per Mcfe, compared to $104.6 million, or $0.57 per Mcfe, for 2011, a decrease of $20.8 million, or 19.9%. Net general and administrative expenses for 2011 were $104.6 million, or $0.57 per Mcfe, compared with $105.1 million, or $0.92 per Mcfe, in 2010, a decrease of $0.5 million, or 0.5%.

Significant components of the net decreases in general and administrative expense between 2012 and 2011 were a result of:

- decreased personnel costs of $15.1 million primarily related to a reduction in employee headcount, a decrease in contract labor costs and lower cash bonus payments in 2012;
- decreased share based compensation expenses of $1.0 million related to a reduction in headcount and decrease in the number of options granted in 2012;
- decreased travel costs of $1.9 million related to higher travel costs incurred in the prior year, a substantial part of which was associated with the former acquisition proposal;
- decreased office expenses of $0.8 million, employee development costs of $1.9 million, relocation costs of $1.6 million, environmental and safety costs of $0.9 million and information technology costs of $1.7 million, all of which were primarily related to our emphasis on cost reductions and reduced drilling activity; and
- increased operated overhead recoveries of $2.1 million arising from additional wells drilled in 2012 and 2011.

The net decreases in general and administrative expense were partially offset by increased legal expenses of $0.6 million, $1.0 million in engineering expenses related to technical evaluation software licenses and lower technical service recoveries of $3.8 million arising from decreased employee costs in 2012.

Significant variances between 2011 and 2010 included the following items:

- increased personnel costs of $11.9 million, including additional technical resources in our Appalachia area and approximately $6.6 million attributed to an employee retention plan; and
- increased expenditures associated with environmental training and safety programs of $2.4 million.

The above increases were offset by:

- lower share-based compensation of $4.9 million;
- lower legal costs of $1.7 million;
- lower travel and relocation related costs of $2.0 million;
- reductions in office related expenses of $1.6 million attributable to office lease terminations in 2010; and

- increased technical service recoveries, operator overhead reimbursements and capitalized costs of $10.9 million.

Other operating items

Our other operating expenses of $17.0 million for the year ended December 31, 2012 relate to the retroactive Pennsylvania impact fee discussed in *Production and ad valorem taxes,* resolution of various title defect adjustments, legal settlements, and losses related to equipment sales and inventory write-downs. We elected to report the retroactive portion of the Pennsylvania impact fee as a component of other operating items as the retroactive amount would disproportionately impact comparative periods in future quarters. Other operating expenses of $23.8 million for 2011 included expenses related to various lawsuits, the impairment of treating facilities in our Vernon Field, write-downs of inventory items and costs associated with the former acquisition proposal that was terminated in July 2011. For the year ended December 31, 2010, other items represented a net reduction to total costs and expenses of $509.9 million. Significant components of this amount in 2010 include a gain on the formation of the Appalachia JV of $528.9 million. This gain was partially offset by professional fees incurred by a special committee of our board of directors to evaluate strategic opportunities, valuation allowances to the carrying costs from sales of our field inventories, conventional rig contract terminations and certain legal costs.

Interest expense

Interest expense for 2012 was $73.5 million as compared to $61.0 million for 2011. The $12.5 million increase in 2012 is due to the increase in interest expense related to the EXCO Resources Credit Agreement and decreases of capitalized interest related to the decline in additions to our unproved oil and natural gas properties. The increases were offset by a $1.4 million decrease in other interest expense related to a $1.2 million fee made in 2011 in connection with the formation of the TGGT credit facility.

Interest expense for 2011 was $61.0 million as compared to $45.5 million for 2010, an increase of $15.5 million. The $15.5 million increase in 2011 is due primarily to a net increase of interest expense of $19.1 million related to our 2018 Notes and our 7 1/4% Senior Notes due 2011, or the 2011 Notes, which were redeemed in September 2010, and a net increase of interest expense of $4.9 million related to our credit agreements. These increases were partially offset by a $9.3 million increase in capitalized interest.

The following table presents our interest expense for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,			Year to year change	
(in thousands)	2012	2011	2010	2012-2011	2011-2010
Interest expense:					
2018 Notes	$ 57,394	$ 57,309	$ 16,700	$ 85	$ 40,609
2011 Notes	—	—	21,532	—	(21,532)
EXCO Resources Credit Agreement	31,068	23,517	12,609	7,551	10,908
EXCO Operating Credit Agreement (1)	—	—	6,008	—	(6,008)
Amortization and write-off of deferred financing costs on EXCO Resources Credit Agreement	6,776	6,833	3,740	(57)	3,093
Amortization of deferred financing costs on EXCO Operating Credit Agreement	—	—	4,436	—	(4,436)
Amortization of deferred financing costs on 2018 Notes	1,868	1,867	537	1	1,330
Interest rate swaps settlement	—	—	2,063	—	(2,063)
Fair market value adjustment on interest rate swaps	—	—	(2,018)	—	2,018
Capitalized interest	(23,809)	(30,083)	(20,829)	6,274	(9,254)
Other	195	1,580	755	(1,385)	825
Total interest expense	$ 73,492	$ 61,023	$ 45,533	$ 12,469	$ 15,490

(1) The EXCO Operating Credit Agreement, which was a separate credit agreement held by our wholly-owned subsidiary, EXCO Operating Company, was consolidated with the EXCO Resources Credit Agreement on April 30, 2010.

Derivative financial instruments

We enter into derivative financial instruments to mitigate our exposure to commodity prices, protect our returns on investments, and achieve a more predictable cash flow from operations. These transactions limit exposure to declines in commodity prices, but also limit the benefits we would realize if commodity 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.

In July 2012, the Commodity Futures Trading Commission approved the final rule that, among other things, exempts end users from the clearing requirements for swaps under the Dodd-Frank Act. We believe that EXCO qualifies as an end user under this final rule. As a result, the swaps we enter into with our derivative counterparties are not subject to clearing requirements that would generally require us to post collateral to secure our derivative obligations.

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 expense" in our Consolidated Statements of Operations.

	Years Ended December 31,			Year to year change	
(in thousands)	**2012**	**2011**	**2010**	**2012-2011**	**2011-2010**
Derivative financial instrument activities:					
Cash settlements on derivative financial instruments, excluding early terminations	$ 202,078	$ 135,417	$ 179,519	$ 66,661	$ (44,102)
Cash settlements on early terminations of derivative financial instruments	—	—	37,936	—	(37,936)
Non-cash change in fair value of derivative financial instruments	(135,945)	84,313	(70,939)	(220,258)	155,252
Total derivative financial instrument activities	$ 66,133	$ 219,730	$ 146,516	$ (153,597)	$ 73,214

The following table presents our natural gas prices, before and after the impact of the cash settlement of our derivative financial instruments.

	Years Ended December 31,			Year to year change	
Average realized pricing:	**2012**	**2011**	**2010**	**2012-2011**	**2011-2010**
Oil per Bbl	$ 88.24	$ 91.01	$ 76.18	$ (2.77)	$ 14.83
Natural gas liquids per Bbl	43.27	58.69	45.91	(15.42)	12.78
Natural gas per Mcf	2.53	3.72	4.12	(1.19)	(0.40)
Natural gas equivalent per Mcfe	$ 2.88	$ 4.10	$ 4.51	$ (1.22)	$ (0.41)
Cash settlements on derivative financial instruments, per Mcfe	1.06	0.74	1.57	0.32	(0.83)
Net price per Mcfe, including derivative financial instruments before early terminations	$ 3.94	$ 4.84	$ 6.08	$ (0.90)	$ (1.24)
Cash settlements on early terminations of derivative financial instruments, per Mcfe	—	—	0.33	—	(0.33)
Net price per Mcfe, derivative financial instruments	$ 3.94	$ 4.84	$ 6.41	$ (0.90)	$ (1.57)

Our total cash settlements for 2012 were $202.1 million or $1.06 per Mcfe, compared to cash settlements of $135.4 million or $0.74 per Mcfe, in 2011. Our cash settlements were $217.5 million, or $1.90 per Mcfe, in 2010. As noted above, the significant fluctuations between settlements on our derivative financial instruments demonstrate the volatility in commodity prices.

The non-cash mark-to-market changes in the value of our oil and natural gas derivative financial instruments for 2012 resulted in losses of $135.9 million, compared to gains of $84.3 million and losses of $70.9 million for 2011 and 2010, respectively. The significant fluctuations were attributable to high volatility in oil and natural gas prices between each of the periods. 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 business 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.

Income taxes

The following table presents a reconciliation of our income tax provision (benefit) for the years ended December 31, 2012, 2011 and 2010.

	Years Ended December 31,		
(in thousands)	**2012**	**2011**	**2010**
Federal income taxes (benefit) provision at statutory rate of 35%	$ (487,649)	$ 7,909	$ 235,737
Increases (reductions) resulting from:			
Goodwill	—	—	11,556
Adjustments to the valuation allowance	544,949	(11,665)	(277,182)
Non-deductible compensation	1,893	1,760	2,098
State taxes net of federal benefit	(59,406)	1,554	29,050
Other	213	442	349
Total income tax provision	$ —	$ —	$ 1,608

During 2012, our net income was significantly impacted by ceiling test write downs. The tax benefits arising from the ceiling test write-downs were offset by a valuation allowance. There were no material sales transactions during the year to impact taxable income. The net result is no income tax provision for 2012.

During 2011, our taxable income was offset by the utilization of net operating losses and a corresponding decrease to previously recognized valuation allowances against deferred tax assets. The net result was no income tax provision for 2011.

During 2010, our taxable income was impacted by gains attributable to the formation of the Appalachia JV, offset by the utilization of net operating losses and a corresponding decrease to previously recognized valuation allowances against deferred tax assets. The 2010 income tax provision represents an alternative minimum tax and state income tax liability

We adopted the provisions of FASB ASC 740-10, *Income Taxes*, or ASC 740-10, on January 1, 2007. As a result of the implementation of ASC 740-10, we did not recognize any liabilities for unrecognized tax benefits. As of December 31, 2012, 2011 and 2010, our policy was to recognize interest related to unrecognized tax benefits, including penalties, in operating expenses. We have not accrued any interest or penalties relating to unrecognized tax benefits in the current financial statements.

We file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. With few exceptions, we are no longer subject to U.S. federal, state and local examinations by tax authorities for years before 2004. We have been notified by the IRS that they plan to audit selected pass-through entities during 2013 for tax years starting in 2010.

Selected EXCO/HGI Partnership information

The EXCO/HGI Partnership was formed on February 14, 2013, which resulted in us reducing our economic interest in the properties contributed to 25.5%. The following table presents selected pro forma operating and financial information for the year ended December 31, 2012 as if the EXCO/HGI Partnership was formed on January 1, 2012:

		Pro forma adjustments		
(dollars in thousands, except per unit rate)	Historical EXCO	Total Partnership	EXCO's 25.5% share	Pro forma EXCO
Reserves (as of December 31, 2012):				
Total proved (Mmcfe)	1,009,386	(404,789)	103,221	707,818
Production:				
Total production (Mmcfe)	189,928	(36,647)	9,345	162,626
Average production (Mmcfe/d)	519	(100)	26	445
Revenues:				
Revenues, excluding derivatives	$ 546,609	$ (159,447)	$ 40,659	$ 427,821
Average realized price ($/Mcfe)	2.88	4.35	4.35	2.63
Expenses:				
Direct operating costs	77,127	(46,824)	11,940	42,243
Per Mcfe	0.41	1.28	1.28	0.26
Production and ad valorem taxes	27,483	(18,956)	4,834	13,361
Per Mcfe	0.14	0.52	0.52	0.08
Gathering and transportation	102,875	(12,841)	3,275	93,309
Per Mcfe	0.54	0.35	0.35	0.57

The pro forma information is not necessarily indicative of what actually would have occurred if the transaction had been completed as of January 1, 2012, nor is it necessarily indicative of future consolidated results.

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 capital market conditions are favorable. Due to our emphasis on shale resource plays, we have incurred significant development expenditures which have exceeded our cash flows from operations since 2008. As a result of the low natural gas price outlook, our 2013 capital budget limits capital expenditures to approximate our expected cash flows from operations. In addition, we entered into the EXCO/HGI Partnership in February 2013 and we are evaluating potential transactions to enhance our liquidity, including the possible sale of our interest in TGGT. Other factors which could impact our liquidity, capital resources and capital commitments in 2013 and future years include the following:

- the level of planned drilling activities;
- the results of our ongoing drilling programs;
- our ability to fund or finance acquisitions of oil and natural gas properties;
- our ability to reduce and maintain lower operating, general and administrative expenses and capital expenditure programs in response to continued low natural gas prices;
- reduced oil and natural gas revenues resulting from, among other things, low natural gas prices and lower production from reductions to our drilling and development activities;
- reduced operating cash flows as a result of the EXCO/HGI Partnership transaction which resulted in the sale of 74.5% of a substantial portion of our conventional assets;

- decreases in the percentage of our production covered by derivative financial instruments, coupled with expiration of higher priced derivative financial instruments, including certain derivative financial instruments that were assigned to the EXCO/HGI Partnership;
- potential acquisitions and/or sales of oil and natural gas properties or other assets;
- reductions of our borrowing base under the EXCO Resources Credit Agreement; and
- our ability to maintain compliance with debt covenants as a result of low natural gas prices.

While we believe our existing capital resources, including our cash flow from operations and borrowing capacity under the EXCO Resources Credit Agreement, will be sufficient to conduct our operations through 2013, there are certain risks arising from the depressed natural gas prices that could impact our ability to meet debt covenants in future periods. In particular, our ratio of consolidated funded indebtedness to consolidated EBITDAX, as defined in the EXCO Resources Credit Agreement, is computed using a trailing 12 month computation of EBITDAX and only includes operations from non-guarantor subsidiaries and unconsolidated joint ventures to the extent that cash is distributed to entities under the EXCO Resources Credit Agreement. As a result, our ability to maintain compliance with this covenant is negatively impacted when oil and/or natural gas prices and production decline over an extended period of time. In addition, the formation of the EXCO/HGI Partnership resulted in a reduction to our outstanding debt and a reduction of our borrowing base from $1.3 billion to $900.0 million. Our results of operations, cash flows from operations and Proved Reserves will be reduced by the 74.5% economic interest acquired by HGI in the first quarter of 2013.

In addition to the covenants in the EXCO Resources Credit Agreement, the indenture governing our 2018 Notes contains a debt incurrence test on secured borrowings based on (i) the greater of $1.2 billion, subject to certain permanent reductions, or (ii) 75% of adjusted consolidated net tangible assets, or ACNTA, as defined in the indenture. A significant component of the ACNTA valuation is based on the PV-10 value of our Proved Reserves, computed using SEC pricing as of the beginning of each year. On January 1, 2012, the ACNTA limitation was $2.1 billion. Due primarily to a significant reduction in our PV-10 at December 31, 2012 , the ACNTA limitation was reduced to $1.2 billion on January 1, 2013. While ACNTA limits our ability to incur secured indebtedness, we are not prevented from incurring unsecured financing under the indenture. Following the formation of the EXCO/HGI Partnership, we estimate the ACNTA limitation will be reduced to $900.0 million.

In response to the depressed natural gas prices, we reduced our drilling plans in 2012. We expect lower production volumes in 2013 and into 2014 as a result of drilling reductions. During 2012, we sold our corporate aircraft, reduced contract and full-time personnel by approximately 62.4% and 15.9%, respectively, and implemented cost saving initiatives in our field operations. The liquidity provided from the formation of the EXCO/HGI Partnership in February 2013 will assist us in executing our business plan. However, the combination of our reduced borrowing base, lower production volumes and the expiration of higher priced derivative financial instruments may require us to seek alternative financing arrangements, further reduce costs or sell assets.

Our capital budget for 2013 is $273.0 million and reflects continued focus on the development and appraisal of the Haynesville and Marcellus shale plays and maintenance of our land holdings across our portfolio. The 2013 capital expenditure budget does not include any carried drilling costs from BG Group as all of the contractual carry commitments have been utilized.

We believe our capital expenditure budget for 2013 will meet our operational objectives while maintaining or preserving sufficient liquidity.

The following table presents our liquidity and financial position as of December 31, 2012 and February 19, 2013.

(in thousands)	December 31, 2012	February 19, 2013
Cash (1)	$ 115,729	$ 86,413
Drawings under the EXCO Resources Credit Agreement	1,107,500	534,235
2018 Notes (2)	750,000	750,000
Total debt	1,857,500	1,284,235
Net debt	$ 1,741,771	$ 1,197,822
Borrowing base (3)	$ 1,300,000	$ 900,000
Unused borrowing base (4)	$ 185,393	$ 358,258
Unused borrowing base plus cash (1) (4)	$ 301,122	$ 444,671

(1) Includes restricted cash of $70.1 million at December 31, 2012 and $71.4 million at February 19, 2013.
(2) Excludes unamortized bond premium of $8.5 million at December 31, 2012 and $8.4 million at February 19, 2013.
(3) Following formation of the EXCO/HGI Partnership, the borrowing base under the EXCO Resources Credit Agreement was reduced to $900.0 million to reflect the contribution of assets to the partnership.
(4) Net of $7.1 million and $7.5 million in letters of credit as of December 31, 2012 and February 19, 2013, respectively.

Events affecting liquidity

On February 14, 2013, we formed the EXCO/HGI Partnership. Pursuant to the agreements governing the partnership, we contributed our conventional non-shale assets in East Texas and North Louisiana and our shallow Canyon Sand and other conventional assets in the Permian Basin in West Texas to the EXCO/HGI Partnership in exchange for cash proceeds of $573.3 million, after customary preliminary purchase price adjustments, and a 25.5% economic interest in the partnership. HGI owns the remaining 74.5% economic interest in the EXCO/HGI Partnership. Proceeds received from were used to reduce outstanding borrowings under the EXCO Resources Credit Agreement. As a result of the transaction, the borrowing base under the EXCO Resources Credit Agreement was reduced from $1.3 billion to $900.0 million to reflect the contribution of our properties to the EXCO/HGI Partnership.

Our 2013 results of operations and cash flows from operations will be reduced by the 74.5% economic interest acquired by HGI.

Immediately following closing of the EXCO/HGI Partnership entered into an agreement to purchase all of the shallow Cotton Valley assets within our joint venture with BG Group for $132.5 million, subject to customary closing adjustments. A deposit of $25.0 million was paid to BG Group when the agreement was executed. The transaction is expected to close in the first quarter of 2013 and will be funded with borrowing from the EXCO/HGI Partnership Credit Agreement.

Although weaknesses in natural gas prices continue, we believe that our capital resources from existing cash balances, anticipated cash flow from operating activities and available borrowing capacity under the EXCO Resources Credit Agreement will be adequate to execute our corporate strategies and to meet debt service obligations during 2013.

Historical sources and uses of funds

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

	Years Ended December 31,		
(in thousands)	**2012**	**2011**	**2010**
Net cash provided by operating activities	$ 514,786	$ 428,543	$ 339,921
Net cash used in investing activities	(427,094)	(709,531)	(712,854)
Net cash provided by (used in) financing activities	(74,045)	268,756	348,755
Net increase (decrease) in cash	$ 13,647	$ (12,232)	$ (24,178)

Our primary sources of cash in 2012 were cash flows from operations and borrowings under the EXCO Resources Credit Agreement. As of December 31, 2012, our total unrestricted and restricted cash was $115.7 million compared with $187.9 million as of December 31, 2011. The decrease in our restricted cash was primarily due to lower restricted cash requirements in our East Texas/North Louisiana JV as a result of reduced drilling activity. Our consolidated debt was $1.8 billion as of December 31, 2012 compared with $1.9 billion as of December 31, 2011.

Cash flows from operating activities

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. The depressed natural gas prices in 2012 continued to negatively impact our cash flows from operating activities, with the average realized price per Mcfe, including net derivative settlement proceeds, declining from $4.84 per Mcfe for the year ended December 31, 2011 to $3.94 per Mcfe for the year ended December 31, 2012, or 18.6%.

Net cash provided by operating activities for the year ended December 31, 2012 was $514.8 million compared with $428.5 million for the year ended December 31, 2011. The 20.1% increase in 2012 was primarily attributable to the higher settlement proceeds on our derivatives and favorable working capital conversions, offset by lower average prices received. As of February 19, 2013, our cash and cash equivalent balance was $15.0 million and our restricted cash account, which is used for Haynesville/Bossier shale development operations, was $71.4 million.

Investing activities

Our investing activities consist primarily of drilling and development expenditures, capital contributions to our joint ventures, and acquisitions. Our acquisitions since 2009 have been focused primarily on undeveloped shale acreage in our core areas and have been funded primarily with borrowings under the EXCO Resources Credit Agreement. Future acquisitions are dependent on oil and natural gas prices, availability of producing properties and attractive acreage and availability of borrowing capacity under the EXCO Resources Credit Agreement or from other capital sources.

For the year ended December 31, 2012, our cash flows used in investing activities were $427.1 million, compared with $709.5 million of cash flows used in investing activities for the year ended December 31, 2011. Cash flows from investing activities for the year ended December 31, 2011 included a $125.0 million distribution from TGGT and receipt of $391.0 million from BG Group for its 50% share of acquisitions in our Appalachia and East Texas/North Louisiana areas.

Capital expenditures

The following table presents our capital expenditures for the years ended December 31, 2012, 2011 and 2010. The 2011 oil and natural gas acquisitions include the $459.4 million we funded for the Chief transaction in 2010 as the necessary consents to acquire those assets were not received from third parties until January 11, 2011. Our 2012 lease purchases were primarily in our West Texas region on undeveloped acreage with horizontal drilling opportunities. Our acquisitions in 2011 and 2010 emphasized undeveloped acreage in the Haynesville and Bossier shales in East Texas/North Louisiana and the Marcellus shale in Appalachia. Our 2012 lease purchases were primarily in West Texas on acreage with horizontal drilling potential.

	Years ended December 31,		
(in thousands)	2012	2011	2010
Capital expenditures:			
Oil and natural gas property acquisitions (1)	$ 3,349	$ 755,520	$ 533,941
Lease purchases (2)	46,678	63,367	95,843
Development capital expenditures	403,342	855,451	346,582
Seismic	2,480	10,146	21,335
Gas gathering and water pipelines	1,044	6,495	23,607
Corporate and other	48,303	65,747	74,427
Total capital expenditures	$ 505,196	$ 1,756,726	$ 1,095,735

(1) Excludes reimbursements from BG Group of $359.1 million in 2011 and $123.5 million in 2010. There were no reimbursements from BG Group in 2012.
(2) Excludes reimbursements from BG Group of $2.1 million in 2012, $31.9 million in 2011 and $58.3 million in 2010.

2013 capital budget

(in millions, except wells)	2013 planned gross wells drilled	2013 planned gross wells completed	2013 capital budget	2012 actual spending (1)	Year to year change
East Texas/North Louisiana	26	42	$ 179.0	$ 283.5	$ (104.5)
Appalachia	5	24	53.0	96.3	(43.3)
Permian (2)	—	—	—	70.6	(70.6)
Corporate and other (3)	—	—	41.0	49.3	(8.3)
Total	31	66	$ 273.0	$ 499.7	$ (226.7)

(1) Includes reimbursements from BG Group of $2.1 million in 2012.

(2) Drilling in the shallow section of the Permian Basin in 2013 will be conducted in the EXCO/HGI Partnership.
(3) Includes $25.0 million of capitalized interest for 2013 and $23.8 million for 2012.

Credit agreements and long-term debt

As of February 19, 2013, the EXCO Resources Credit Agreement had a borrowing base of $900.0 million, with $534.2 million of outstanding indebtedness and $358.3 million of available borrowing capacity. Upon formation of the EXCO/HGI Partnership on February 14, 2013, the borrowing base was reduced from $1.3 billion to the current $900.0 million to reflect the contribution of the assets to the EXCO/HGI Partnership. The current interest rate grid ranges from LIBOR plus 175 bps to 275 bps (or ABR plus 75 bps to 175 bps), depending on the percentages of drawn balances to the borrowing base as defined in the agreement. The borrowing base is redetermined semi-annually, with us and the lenders having the right to request interim unscheduled redeterminations in certain circumstances. The EXCO Resources Credit Agreement matures on April 1, 2016.

The EXCO/HGI Partnership has a credit agreement secured by its assets with $230.0 million drawn as of February 14, 2013. While we own a 25.5% interest in the EXCO/HGI Partnership, we are not a guarantor of its debt. Terms and conditions of the EXCO/HGI Partnership Credit Agreement are discussed below.

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 HGI. The EXCO Resources Credit Agreement permits certain investments, loans and advances to the unrestricted subsidiaries related to our joint ventures with certain limitations. Unless otherwise permitted, any cash balances of non-guarantor subsidiaries or unconsolidated joint ventures are not security for the EXCO Resources Credit Agreement. The EXCO Resources Credit Agreement has regularly scheduled semi-annual borrowing base redeterminations each April and October, with EXCO and the lenders having the right to request interim unscheduled redeterminations in certain circumstances.

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, of 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 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 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 the indenture governing the 2018 Notes.

Based on a one month LIBOR of 0.2% on February 19, 2013, we would incur an interest rate of 2.5% on any new indebtedness we may incur under the EXCO Resources Credit Agreement.

As of December 31, 2012, we were in compliance with the financial covenants contained in the EXCO Resources Credit Agreement, as amended, which requires 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 4.5 to 1.0 at the end of any fiscal quarter ending on or after March 31, 2012.

2018 Notes

As of December 31, 2012 and February 19, 2013, we had outstanding $750.0 million aggregate principal amount of 7.5% senior unsecured notes maturing on September 15, 2018. The 2018 Notes are guaranteed on a senior unsecured basis by a majority of EXCO's subsidiaries, with the exception of certain non-guarantor subsidiaries and our jointly-held equity investments with BG Group and HGI. Our equity investments with BG Group and HGI, other than OPCO, are designated as unrestricted subsidiaries under the indenture governing the 2018 Notes. The unamortized discount on the 2018 Notes at December 31, 2012 was $8.5 million. The estimated fair value of the 2018 Notes, based on quoted market prices, was $716.3 million on December 31, 2012.

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

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.

The foregoing descriptions are not complete and are qualified in their entirety by the EXCO Resources Credit Agreement and the indenture governing the 2018 Notes.

EXCO/HGI Partnership Credit Agreement

In connection with its formation, the EXCO/HGI Partnership entered into the EXCO/HGI Partnership Credit Agreement which has an initial borrowing base of $400.0 million. Borrowings under the EXCO/HGI Partnership Credit Agreement are secured by properties contributed to the EXCO/HGI Partnership and we do not guarantee the EXCO/HGI Partnership's debt. The EXCO/HGI Partnership is not a guarantor to the EXCO Resources Credit Agreement. As of February 14, 2013, $230.0 million was drawn under this agreement. The interest rate grid ranges from LIBOR plus 175 bps to 275 bps (or ABR plus 75 bps to 175 bps), depending on the percentages of drawn balances to the borrowing base as defined in the agreement. The borrowing base is redetermined semi-annually, with us and the lenders having the right to request interim unscheduled redeterminations in certain circumstances. The EXCO/HGI Partnership Credit Agreement matures on February 14, 2018.

Borrowings under the EXCO/HGI Partnership 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/HGI Partnership Credit Agreement, of the oil and natural gas properties evaluated by the lenders for purposes of establishing the borrowing base. Pursuant to the agreement, within 60 days of formation of the EXCO/HGI Partnership, the partnership is required to enter into derivative financial instruments covering not less than 75.0% of its forecasted proved producing natural gas production for 2013 and 50.0% of such forecasted production for 2014. For future years, the EXCO/HGI Partnership is permitted to have derivative financial instruments covering no more than 100% of the forecasted production from proved developed producing reserves (as defined in the agreement) for any month during the first two years of the forthcoming five year period, 90% of the forecasted production from proved developed producing reserves for any month during the third year of the forthcoming five year period and 85% of the forecasted production from proved developed producing reserves for any month during the fourth and fifth year of the forthcoming five year period.

The financial covenants contained in the EXCO/HGI Partnership Credit Agreement 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 4.5 to 1.0 at the end of any fiscal quarter.

Derivative financial instruments

We use oil and natural gas derivatives to manage our exposure to commodity price 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. 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.

Our production is generally sold at prevailing market prices. However, we periodically enter into oil and natural gas derivative 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. These transactions limit our exposure to declines in prices, but also limit the benefits we would realize if oil and natural gas prices increase. The following table sets forth our oil and natural gas derivative financial instruments measured at fair value as of January 31, 2013. At formation of the EXCO/HGI Partnership, we assigned derivative financial instruments covering 2013 natural gas of approximately 39,000 Mmbtus per day at an average price of $3.82 per Mmbtu, 10,000 Mmbtus per day for 2014 at an average price of $4.24 per Mmbtu and oil swaps covering 1,500 Bbls per day at $94.05 per Bbl for 2013. The derivative financial instruments presented within this table do not include any swap contracts that were assigned to the EXCO/HGI Partnership at its formation.

	Volume Mmbtus/ Bbls	Weighted average strike price per Mmbtu/Bbl	Fair value at January 31, 2013
Natural gas:			
Swaps:			
2013	60,225	$ 4.26	$ 38,697
2014	52,925	4.26	11,107
2015	28,288	4.31	1,636
Calls:			
2013	20,075	4.29	(1,561)
2014	20,075	4.29	(7,068)
2015	20,075	4.29	(11,056)
Total natural gas	201,663		$ 31,755
Oil:			
Swaps:			
2013	—	$ —	$ —
Calls:			
2013	—	—	—
2014	365	100.00	(2,606)
2015	365	100.00	(2,719)
Total oil	730		(5,325)
Total oil and natural gas derivatives			$ 26,430

At January 31, 2013, the average forward NYMEX oil prices per Bbl for the remainder of 2013 and calendar years 2014 and 2015 were $98.14, $94.14, and $90.24, respectively, and the average forward NYMEX natural gas prices per Mmbtu for the remainder of 2013 and calendar years 2014 and 2015 were $3.58, $4.05, and $4.26, 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.

Off-balance sheet arrangements

As of December 31, 2012, we had no arrangements or any guarantees of off-balance sheet debt to third parties.

Contractual obligations and commercial commitments

The following table presents our contractual obligations and commercial commitments as of December 31, 2012:

	Payments due by period				
(in thousands)	Less than one year	One to three years	Three to five years	More than five years	Total
2018 Notes (1)	$ —	$ —	$ —	$ 750,000	$ 750,000
EXCO Resources Credit Agreement (2)	—	—	1,107,500	—	1,107,500
Firm transportation services (3)	92,872	184,816	178,569	279,738	735,995
Other fixed commitments (4)	12,160	12,913	6,777	—	31,850
Drilling contracts	10,854	—	—	—	10,854
Operating leases and other	16,058	12,047	1,151	—	29,256
Total contractual obligations (5)	$ 131,944	$ 209,776	$ 1,293,997	$ 1,029,738	$ 2,665,455

(1) The 2018 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 1, 2016. The interest is payable at LIBOR plus 175 bps to LIBOR plus 275 bps, or from ABR plus 75 bps to ABR plus 175 bps, depending on borrowing base usage.
(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) Other fixed commitments are primarily related to completion service contracts.
(5) Excludes commitments of our equity method investees, TGGT and OPCO, as neither EXCO nor any of its subsidiaries are guarantors of these commitments. TGGT's commitments as of December 31, 2012, which consisted primarily of compression equipment and office leases, totaled $5.9 million. OPCO's commitments as of December 31, 2012, which consisted primarily of firm transportation contracts, drilling contracts and completion services, totaled $54.1 million.

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 fluctuations, protect our returns on investments, and achieve a more predictable cash flow in connection with our financing activities and borrowings related to these activities. These transactions limit exposure to declines in prices, but also limit the benefits we would realize if oil and natural gas 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.

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.

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. Upon formation of the EXCO/HGI Partnership, we assigned 2013 natural gas swaps covering 30,000 Mmbtu per day at an average price of $3.92 per Mmbtu and 2014 natural gas swaps covering 10,000 Mmbtu per day at an average price of $4.24 per Mmbtu to the EXCO/HGI Partnership. The fair value of these natural gas swaps, which are included in the following table, was an asset of approximately $4.9 million.

In January 2013, we received approximately $2.1 million for early settlements of our 2013 oil swaps that existed at December 31, 2012 and entered into new oil swaps for 2013 covering 1,500 Bbls per day at an average of $94.05 per Bbl. As soon as practicable after the formation of the EXCO/HGI Partnership, we intend to assign these swaps to the EXCO/HGI

Partnership. In addition, we expect to settle all open oil call options soon after the formation of the EXCO/HGI Partnership. As of December 31, 2012, we had derivative financial instruments in place for the volumes and prices shown below:

(in thousands, except prices)	Volume Mmbtus/Bbls	Weighted average strike price per Mmbtu/Bbl	Fair value at December 31, 2012
Natural gas:			
Swaps:			
2013	71,175	$ 4.21	$ 46,929
2014	56,575	4.26	12,670
2015	28,288	4.31	2,392
Calls:			
2013	20,075	4.29	(2,265)
2014	20,075	4.29	(7,632)
2015	20,075	4.29	(11,409)
Total natural gas	216,263		$ 40,685
Oil:			
Swaps:			
2013	365	$ 99.96	$ 2,443
Calls:			
2013	—	—	—
2014	365	100.00	(2,768)
2015	365	100.00	(3,071)
Total oil	1,095		(3,396)
Total oil and natural gas derivatives			$ 37,289

At December 31, 2012, the average forward NYMEX oil prices per Bbl for calendar years 2013, 2014, and 2015 were $93.22, $92.16, and $90.02, respectively, and the average forward NYMEX natural gas prices per Mmbtu for the calendar years 2013, 2014 and 2015 were $3.54, $4.03, and $4.23, 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.

Interest rate risk

At December 31, 2012, our exposure to interest rate changes related primarily to borrowings under the EXCO Resources Credit Agreement and interest earned on our short-term investments. The interest rate per annum on the 2018 Notes is fixed at 7.5%. Interest is payable on borrowings under the EXCO Resources 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, 2012, we had approximately $1.1 billion in outstanding borrowings under the EXCO Resources Credit Agreement. A 1% change in interest rates (100 bps) based on the variable borrowings as of December 31, 2012 would result in an increase or decrease in our interest expense of $11.1 million per year. The interest we pay on these borrowings is set periodically based upon market rates.

Item 8. Financial Statements and Supplementary Data

EXCO Resources, Inc.

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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, 2012. 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, 2012, our internal control over financial reporting was effective based on those criteria.

The effectiveness of EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2012 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which appears herein.

By:	/s/ Douglas H. Miller	By:	/s/ Stephen F. Smith
Title:	Chief Executive Officer	Title:	President and Chief Financial Officer

Dallas, Texas
February 21, 2013

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 (the Company) as of December 31, 2012 and 2011, and the related consolidated statements of operations, cash flows, and changes in shareholders' equity for each of the years in the three-year period ended December 31, 2012. We also have audited EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2012, 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 these consolidated financial statements, 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 these consolidated financial statements and an opinion on the Company's internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (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, 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, 2012 and 2011, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles. Also in our opinion, EXCO Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Dallas, Texas
February 21, 2013

EXCO RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(in thousands)	December 31, 2012	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 45,644	$ 31,997
Restricted cash	70,085	155,925
Accounts receivable, net:		
Oil and natural gas	84,348	88,518
Joint interest	69,446	170,918
Other	15,053	28,488
Inventory	5,705	8,345
Derivative financial instruments	49,500	164,002
Other	22,085	29,815
Total current assets	361,866	678,008
Equity investments	347,008	302,833
Oil and natural gas properties (full cost accounting method):		
Unproved oil and natural gas properties and development costs not being amortized	470,043	667,342
Proved developed and undeveloped oil and natural gas properties	2,715,767	3,392,146
Accumulated depletion	(1,945,565)	(1,657,165)
Oil and natural gas properties, net	1,240,245	2,402,323
Gas gathering assets	130,830	136,203
Accumulated depreciation and amortization	(34,364)	(29,104)
Gas gathering assets, net	96,466	107,099
Office, field and other equipment, net	20,725	42,384
Deferred financing costs, net	22,584	29,622
Derivative financial instruments	16,554	11,034
Goodwill	218,256	218,256
Other assets	28	28
Total assets	$ 2,323,732	$ 3,791,587

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share and share data)	December 31, 2012	December 31, 2011
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 83,240	$ 117,968
Revenues and royalties payable	134,066	148,926
Accrued interest payable	17,029	17,973
Current portion of asset retirement obligations	1,200	732
Income taxes payable	—	—
Derivative financial instruments	2,396	1,800
Total current liabilities	237,931	287,399
Long-term debt	1,848,972	1,887,828
Deferred income taxes	—	—
Derivative financial instruments	26,369	—
Asset retirement obligations and other long-term liabilities	61,067	58,028
Commitments and contingencies	—	—
Shareholders' equity:		
Preferred stock, $0.001 par value; 10,000,000 authorized shares; none issued and outstanding	—	—
Common stock, $0.001 par value; 350,000,000 authorized shares; 218,126,071 shares issued and 217,586,850 shares outstanding at December 31, 2012; 217,245,504 shares issued and 216,706,283 shares outstanding at December 31, 2011	215	215
Additional paid-in capital	3,200,067	3,181,063
Accumulated deficit	(3,043,410)	(1,615,467)
Treasury stock, at cost; 539,221 shares at December 31, 2012 and December 31, 2011	(7,479)	(7,479)
Total shareholders' equity	149,393	1,558,332
Total liabilities and shareholders' equity	$ 2,323,732	$ 3,791,587

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share data)	Years Ended December 31, 2012	2011	2010
Revenues:			
Oil and natural gas	$ 546,609	$ 754,201	$ 515,226
Costs and expenses:			
Oil and natural gas operating costs	77,127	84,766	84,145
Production and ad valorem taxes	27,483	23,875	24,039
Gathering and transportation	102,875	86,881	54,877
Depletion, depreciation and amortization	303,156	362,956	196,963
Write-down of oil and natural gas properties	1,346,749	233,239	—
Accretion of discount on asset retirement obligations	3,887	3,652	3,758
General and administrative	83,818	104,618	105,114
(Gain) loss on divestitures and other operating items	17,029	23,819	(509,872)
Total costs and expenses	1,962,124	923,806	(40,976)
Operating income (loss)	(1,415,515)	(169,605)	556,202
Other income (expense):			
Interest expense	(73,492)	(61,023)	(45,533)
Gain on derivative financial instruments	66,133	219,730	146,516
Other income	969	788	327
Equity income	28,620	32,706	16,022
Total other income (expense)	22,230	192,201	117,332
Income (loss) before income taxes	(1,393,285)	22,596	673,534
Income tax expense	—	—	1,608
Net income (loss)	$ (1,393,285)	$ 22,596	$ 671,926
Earnings (loss) per common share:			
Basic:			
Net income (loss)	$ (6.50)	$ 0.11	$ 3.16
Weighted average common shares outstanding	214,321	213,908	212,465
Diluted:			
Net income (loss)	$ (6.50)	$ 0.10	$ 3.11
Weighted average common and common equivalent shares outstanding	214,321	216,705	215,735

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)	Years Ended December 31, 2012	2011	2010
Operating Activities:			
Net income (loss)	$ (1,393,285)	$ 22,596	$ 671,926
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	303,156	362,956	196,963
Share-based compensation expense	8,926	11,012	16,841
Accretion of discount on asset retirement obligations	3,887	3,652	3,758
Write-down of oil and natural gas properties and other impairment losses on long-lived assets	1,346,749	240,039	—
Income from equity investments	(28,620)	(32,706)	(16,022)
Non-cash change in fair value of derivatives	135,945	(84,313)	68,921
Cash settlements of assumed derivatives	—	—	907
Deferred income taxes	—	—	—
Amortization of deferred financing costs and discount on the 2018 Notes	9,788	9,759	5,014
(Gain) loss on divestitures and sale of other assets	1,303	(479)	(528,888)
Effect of changes in:			
Accounts receivable	112,919	(79,359)	(136,417)
Other current assets	7,090	(5,961)	1,188
Accounts payable and other current liabilities	6,928	(18,653)	55,730
Net cash provided by operating activities	514,786	428,543	339,921
Investing Activities:			
Additions to oil and natural gas properties, gathering systems and equipment	(534,175)	(984,085)	(519,206)
Property acquisitions	(2,748)	(753,286)	(522,765)
Equity method investments	(14,907)	(13,829)	(143,740)
Proceeds from disposition of property and equipment	38,045	449,683	1,044,833
Restricted cash	85,840	5,792	(102,808)
Net changes in advances (to) from Appalachia JV	851	(1,707)	(5,017)
Distributions from equity method investments	—	125,000	—
Deposit on acquisitions	—	464,151	(464,151)
Other	—	(1,250)	—
Net cash used in investing activities	(427,094)	(709,531)	(712,854)
Financing Activities:			
Borrowings under the EXCO Resources Credit Agreement	53,000	706,000	2,072,399
Repayments under the EXCO Resources Credit Agreement	(93,000)	(407,500)	(1,970,963)
Proceeds from issuance of 2018 Notes	—	—	738,975
Repayment of 2011 Notes	—	—	(444,720)
Proceeds from issuance of common stock	1,968	12,063	23,024
Payment of common stock dividends	(34,358)	(34,238)	(29,760)
Payments of common shares repurchased	—	—	(7,479)
Settlements of derivative financial instruments with a financing element	—	—	(907)
Deferred financing costs and other	(1,655)	(7,569)	(31,814)
Net cash provided by (used in) financing activities	(74,045)	268,756	348,755
Net increase (decrease) in cash	13,647	(12,232)	(24,178)
Cash at beginning of period	31,997	44,229	68,407
Cash at end of period	$ 45,644	$ 31,997	$ 44,229
Supplemental Cash Flow Information:			
Cash interest payments	$ 86,298	$ 78,125	$ 54,523
Income tax payments	$ —	$ 1,458	$ 5,460
Supplemental non-cash investing and financing activities:			
Capitalized share-based compensation	$ 7,513	$ 6,406	$ 6,351
Capitalized interest	$ 23,809	$ 30,083	$ 20,829
Issuance of common stock for director services	$ 597	$ 70	$ 61
Accrued restricted stock dividends	$ 300	$ 129	$ —

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Common Stock		Treasury Stock				
(in thousands)	Shares	Amount	Shares	Amount	Additional paid-in capital	Accumulated deficit	Total shareholders' equity
Balance at December 31, 2009	211,905	$ 212	—	$ —	$ 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)
Treasury Stock			(539)	(7,479)			(7,479)
Net income						671,926	671,926
Balance at December 31, 2010	213,736	$ 214	(539)	$ (7,479)	$ 3,151,513	$(1,603,696)	$ 1,540,552
Issuance of common stock	946	1			12,132		12,133
Share-based compensation					17,418		17,418
Restricted stock issued, net of cancellations	2,563	—					—
Common stock dividends						(34,367)	(34,367)
Net income						22,596	22,596
Balance at December 31, 2011	217,245	$ 215	(539)	$ (7,479)	$ 3,181,063	$(1,615,467)	$ 1,558,332
Issuance of common stock	266	—			2,565		2,565
Share-based compensation					16,439		16,439
Restricted stock issued, net of cancellations	615	—					—
Common stock dividends						(34,658)	(34,658)
Net loss						(1,393,285)	(1,393,285)
Balance at December 31, 2012	218,126	$ 215	(539)	$ (7,479)	$ 3,200,067	$(3,043,410)	$ 149,393

See accompanying notes.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and basis of presentation

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 acquisition, exploration, exploitation, development and production of onshore U.S. oil and natural gas properties. Our principal operations are conducted in certain key U.S. 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. Our midstream joint ventures are treated as a separate business segment.

Our primary strategy includes evaluating acquisitions that meet our strategic and financial objectives, and exploiting our shale resource plays. We will carry out this strategy by leveraging our management and technical team's experience, exploiting our multi-year inventory of development drilling locations in our shale plays, actively seeking acquisition opportunities both inside and outside our existing operating areas, managing our liquidity and maintaining financial flexibility. 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.

Our shale resource plays and midstream operations are conducted through four joint ventures with affiliates of BG Group, plc, or BG Group. A brief description of each joint venture follows:

- ***East Texas/North Louisiana JV***

  A joint venture with BG Group covering an undivided 50% interest in a substantial portion of our assets in the East Texas/North Louisiana area including the Haynesville/Bossier shale and conventional shallow producing assets, or the East Texas/North Louisiana JV. The East Texas/North Louisiana JV is governed by a joint development agreement with our subsidiary, EXCO Operating Company, LP, or EXCO Operating, serving as operator. We report the operating results and financial position of the East Texas/North Louisiana JV using proportional consolidation.

- ***TGGT***

  A joint venture with BG Group in which we each own a 50% interest in TGGT Holdings, LLC, or TGGT, which holds most of our East Texas/North Louisiana midstream assets. We use the equity method to account for our 50% investment in TGGT.

- ***Appalachia JV***

  A joint venture with BG Group covering our shallow producing assets and Marcellus shale acreage in the Appalachia region, or the Appalachia JV. EXCO and BG Group each own an undivided 50% interest in the Appalachia JV and a 49.75% working interest in the joint venture's properties. The remaining 0.5% working interest is owned by a jointly owned operating entity, or OPCO, that manages the Appalachia JV operations. Under the terms of the joint development agreement, BG Group agreed to fund 75% of our share of deep drilling and completion costs within our joint venture area up to a total of $150.0 million, or the Appalachia Carry. As of December 31, 2012, the remaining balance of the Appalachia Carry was fully utilized. We use the equity method to account for our investment in OPCO and proportionally consolidate our 49.75% interest in the Appalachia JV.

- ***Appalachia Midstream JV***

  A joint venture with BG Group in which we each own a 50% interest in a midstream company, or the Appalachia Midstream JV, which will develop infrastructure and provide take-away capacity in the Marcellus shale. We use the equity method to account for our 50% investment in the Appalachia Midstream JV.

As discussed in Note 18. Subsequent events, on February 14, 2013, we formed a partnership, or the EXCO/HGI Partnership, with Harbinger Group Inc., or HGI, that manages our conventional non-shale assets in East Texas and North Louisiana and our shallow Canyon Sand and other assets in the Permian Basin of West Texas. We also entered into an agreement with BG Group in which their interest in the same conventional non-shale assets in East Texas/North Louisiana, currently managed in the East Texas/North Louisiana JV, will be purchased by the EXCO/HGI Partnership. We will own a

25.5% economic interest in the EXCO/HGI Partnership and will report its operating results and financial position using proportional consolidation.

The accompanying Consolidated Balance Sheets as of December 31, 2012 and 2011, Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010, Consolidated Statements of Cash Flows and Consolidated Statements of Changes in Shareholders’ Equity for the years ended December 31, 2012, 2011 and 2010 are for EXCO and its subsidiaries. The consolidated financial statements and related footnotes are presented in accordance with generally accepted accounting principles in the United States, or GAAP.

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, 2012 and 2011 and the Consolidated Statements of Operations and Consolidated Statements of Cash Flows and Changes in Shareholders' Equity for the years ended December 31, 2012, 2011 and 2010. 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 the consolidated 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, accrued liabilities, the fair market value of assets and liabilities acquired in business combinations, derivatives and goodwill. 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 principally comprised of our share of an evergreen escrow account with BG Group that is used to fund our share of development operations in the East Texas/North Louisiana JV. Funds held in this escrow account are restricted and can be used solely for 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 $0.4 million and $0.7 million at December 31, 2012 and 2011, 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 years ended December 31, 2012 and 2011, sales to BG Energy Merchants LLC accounted for approximately 36.0% and 36.0%, respectively, of total consolidated revenues. 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.

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, *Derivatives and Hedging*, or ASC 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 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. Our unproved property costs, which include unproved oil and natural gas properties, properties under development, and major development projects, collectively totaled $470.0 million and $667.3 million as of December 31, 2012 and 2011, 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 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. During 2012, we impaired approximately $60.8 million of undeveloped properties to reflect their estimated market price which included certain properties that were no longer part of our drilling plans. There were no impairments of undeveloped properties during the year ended December 31, 2011.

When we acquire significant amounts of undeveloped acreage, we capitalize interest on the acquisition costs in accordance with FASB ASC 835-20*, Capitalization of Interest*. 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 less estimated salvage value are divided by the total estimated quantities of Proved Reserves. This rate is applied to our total production for the quarter, 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.

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 limitation is less than the full cost pool, we are required to record a ceiling test write-down of our oil and natural gas properties. 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 the average price as prescribed by the 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, 2012, the trailing twelve month reference prices were $2.76 per Mmbtu for natural gas at Henry Hub, $94.71 per Bbl of oil for West Texas Intermediate at Cushing, Oklahoma. The price used for NGL's was $46.57 per Bbl and was based on average realized prices in 2012. Each of the reference prices for oil, natural gas and NGLs 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 computations.

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 revisions of such estimate. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered.

Write-down of oil and natural gas properties

For the years ended December 31, 2012 and 2011, we recognized pre-tax ceiling test write-downs of $1.3 billion and $233.2 million, respectively, to our proved oil and natural gas properties. There were no ceiling test write-downs for the year ended December 31, 2010.

Gas gathering assets

Gas gathering assets are capitalized at cost and depreciated on a straight line basis over their estimated useful lives of 20 to 40 years.

During 2011, we sold certain treating facilities in our Vernon Field and recognized a $6.8 million impairment to write the book values down to the selling price.

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 350-20, *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 31st of each year. Losses, if any, resulting from impairment tests will be reflected in operating income in the Consolidated Statements of Operations.

To determine the fair value of our exploration and production reporting unit, a two-part, equally weighted approach is applied. We perform an income approach, which uses a discounted cash flow model to value our business, and a market approach, in which our value is determined using trading metrics and transaction multiples of peer companies.

As a result of testing, the fair value of the business exceeded the carrying value of net assets and we did not record an impairment charge for the periods ending December 31, 2012, 2011 and 2010.

The balance of goodwill as of December 31, 2012 and 2011 was $218.3 million.

Deferred abandonment and asset retirement obligations

We apply FASB ASC 410-20, *Asset Retirement and Environmental Obligations*, or ASC 410-20, 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 represent 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:

	December 31,		
(in thousands)	2012	2011	2010
Asset retirement obligations at beginning of period	$ 58,088	$ 50,292	$ 65,115
Activity during the period:			
Liabilities incurred during the period	971	3,765	1,936
Liabilities settled during the period	(338)	(291)	(503)
Adjustment to liability due to acquisitions	—	1,684	11
Reduction to retirement obligations due to divestitures	(744)	(1,014)	(20,025)
Accretion of discount	3,887	3,652	3,758
Asset retirement obligations at end of period	61,864	58,088	50,292
Less current portion	1,200	732	900
Long-term portion	$ 60,664	$ 57,356	$ 49,392

Our asset retirement obligations are determined using discounted cash flow methodologies based on inputs that are not readily available in public markets. We have no assets that are legally restricted for purposes of settling asset retirement obligations.

Revenue recognition and gas imbalances

We use the sales method of accounting for oil and natural gas revenues. Under the sales method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers. Gas imbalances at December 31, 2012, 2011 and 2010 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 net-back 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.

Gathering and transportation expenses totaled $102.9 million, $86.9 million and $54.9 million for the years ended December 31, 2012, 2011 and 2010, respectively.

We have entered into firm transportation agreements with pipeline companies to facilitate sales from our Haynesville shale production and report these firm transportation costs as a component of gathering and transportation expenses. At the end of 2012, our firm transportation agreements cover an average of 811 Mmcf per day through 2015, with average annual minimum gathering and transportation expenses of approximately $92.6 million per year. For the years 2016 through 2021, our firm transportation agreements range from covering an average of 738 Mmcf per day in 2016 and trend down to 400 Mmcf per day in 2021, with average annual minimum gathering and transportation expenses ranging from approximately $89.5 million per year in 2016 and trending down to $48.9 million in 2021.

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, 2012, 2011 and 2010, we capitalized $22.5 million, $22.9 million and $19.8 million, respectively. The capitalized amounts include $7.5 million, $6.4 million and $6.4 million of share-based compensation for the years ended December 31, 2012, 2011 and 2010, respectively.

Overhead reimbursement fees

We have classified fees from overhead charges billed to working interest owners, including ourselves, of $20.5 million, $18.4 million and $16.2 million, for the years ended December 31, 2012, 2011 and 2010, respectively, as a reduction of general and administrative expenses in the accompanying Consolidated Statements of Operations. Our share of these charges was $10.3 million, $9.6 million and $8.8 million for the years ended December 31, 2012, 2011 and 2010, respectively, and are classified as oil and natural gas production costs.

In addition, we have agreements with BG Group that allow us to bill each other certain personnel costs and related fees incurred on behalf of the East Texas/North Louisiana JV and the Appalachia JV. For the years ended 2012, 2011 and 2010, general and administrative expenses were reduced by $25.2 million, $29.1 million and $23.5 million, respectively, for recoveries of fees for our personnel and services provided to our joint ventures. These recoveries are net of fees charged to us by BG Group for their personnel and services.

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 in accordance with FASB ASC 740, *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 earnings 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 260-10, *Earnings Per Share*. ASC 260-10 requires companies to present two calculations of earnings per share, or EPS; basic and diluted. Basic EPS is based on the weighted average number of common shares outstanding during the period, excluding restricted stock awards. Diluted EPS is computed in the same manner as basic EPS after assuming issuance of common stock for all potentially dilutive equivalent shares, whether vested or exercisable.

Share-based compensation

We account for our share-based compensation in accordance with FASB ASC Topic 718, *Compensation-Stock Compensation*. ASC 718 requires all share-based payments to employees, including grants of employee stock options and restricted stock, 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 or restricted stock.

Our 2005 Long-Term Incentive Plan, as amended, or the 2005 Incentive Plan, provides for the granting of options and other equity incentive awards up to 28,500,000 shares of our common stock in accordance with terms within the agreements. New shares will be issued for any options exercised or awards granted. Under the 2005 Incentive Plan, we have only issued stock options and restricted stock, although the plan allows for other share-based awards.

3. Divestitures, acquisitions and other significant events

2012 Acquisitions and other significant events

During 2012, we made acreage purchases in our Appalachia and Permian regions and sold a portion of our West Virginia acreage for net proceeds of $14.3 million. In addition, as discussed in Note 18. Subsequent events, on February 14, 2013 we contributed most of our Texas and Louisiana conventional asset operations to the EXCO/HGI Partnership, of which we own a 25.5% economic interest.

2011 Acquisitions and other significant events

Chief transaction

On December 21, 2010, we funded the acquisition of undeveloped acreage and oil and natural gas properties in the Marcellus shale from Chief Oil & Gas LLC and related parties for approximately $459.4 million, subject to post-closing title adjustments and customary post-closing purchase price adjustments, or the Chief Transaction. The $459.4 million preliminary purchase price was initially funded into an escrow account pending receipt of a waiver from a third party, which was received on January 11, 2011. Upon receipt of that waiver, the properties were released to us. On February 7, 2011, BG Group elected to participate in the Chief Transaction and funded $229.7 million for their 50% share of the preliminary purchase price. During the third quarter of 2011 we completed post-closing adjustments on the Chief Transaction resulting in a final purchase price of $454.4 million ($227.2 million net to us).

Appalachia transaction

On March 1, 2011, we jointly closed the purchase of Marcellus shale acreage with BG Group, which also included certain shallow production primarily in Jefferson and Clarion counties in Pennsylvania for $82.0 million ($41.0 million net to us), or the Appalachia Transaction.

Haynesville shale acquisition

On April 5, 2011, we purchased land, mineral interests and other assets in DeSoto Parish for $225.2 million, or the Haynesville Shale Acquisition. On May 12, 2011, BG Group elected to participate for its 50% share of the transaction and funded us $112.6 million.

TGGT incident

Late in May 2011 an incident occurred at a TGGT amine treating facility in northwest Red River Parish, Louisiana resulting in an immediate shut-down of the facility. The facility was placed back into service late in the first quarter of 2012. TGGT recognized impairments related to the facility in 2012 totaling $34.9 million ($17.4 million net to us). The impairments reduced equity income.

Former 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. This proposal did not represent a definitive offer and there was no assurance that a definitive offer would be made or accepted, that any agreement would be executed or that any transaction would be consummated.

On January 13, 2011, the special committee of the board of directors announced it would 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 would 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. At the direction of the special committee, the Company adopted a shareholder rights plan, or the Rights Plan, with a one year term. On August 19, 2011, the Board determined to amend the Rights Plan to accelerate the expiration date from the close of business on January 24, 2012 to the close of business on September 30, 2011.

On July 8, 2011, after consultation with its independent financial and legal advisors, the special committee released a statement that its review of strategic alternatives did not result in any firm proposal or any other proposal that was in the best interests of the Company and its shareholders and that they had terminated the review process. On August 12, 2011, our board of directors, following the report of the special committee that it had fulfilled its responsibilities, determined that it was appropriate to disband the special committee. In addition, certain shareholder derivative lawsuits and shareholder class action suits that were filed in connection with the acquisition proposal were either voluntarily non-suited or dismissed in the third quarter of 2011.

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 reduced the purchase price by approximately $45.0 million for post-closing adjustments, lowering the sales 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. 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 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. We make advances to OPCO to provide working capital for our share of properties. These advances are recorded as a prepaid asset and included in "Other" current assets on our Consolidated Balance Sheets and are offset by any payments made by OPCO for our interest in the 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, or Appalachia Midstream, which will pursue construction 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.

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 December 31, 2010.

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 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 acquired in the Common Transaction.

4. Derivative financial instruments

Our primary objective in entering into derivative financial instruments is to manage our exposure to commodity price fluctuations, protect our returns on investments and achieve a more predictable cash flow from operations. These transactions limit exposure to declines in commodity prices, but also limit the benefits we would realize if commodity 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.

We account for our derivative financial instruments in accordance with FASB ASC 815*, Derivatives and Hedging*, 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 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. The table below outlines the classification of our derivative financial instruments on our Consolidated Balance Sheets and their financial impact in our Consolidated Statements of Operations.

Fair Value of Derivative Financial Instruments

(in thousands)	Balance Sheet location	December 31, 2012	December 31, 2011
Commodity contracts	Derivative financial instruments - Current assets	$ 49,500	$ 164,002
Commodity contracts	Derivative financial instruments - Long-term assets	16,554	11,034
Commodity contracts	Derivative financial instruments - Current liabilities	(2,396)	(1,800)
Commodity contracts	Derivative financial instruments - Long-term liabilities	(26,369)	—
Net derivative financial instruments		$ 37,289	$ 173,236

The Effect of Derivative Financial Instruments

	Years Ended December 31,		
(in thousands)	2012	2011	2010
Cash settlements on derivative financial instruments	$ 202,078	$ 135,417	$ 217,455
Non-cash change in fair value of derivative financial instruments	(135,945)	84,313	(70,939)
Gain on derivative financial instruments	$ 66,133	$ 219,730	$ 146,516

Settlements in the normal course of maturities of our derivative financial instrument contracts result in cash receipts from, or cash disbursements to, our derivative contract counterparties. Changes in the fair value of our derivative financial instrument contracts, which includes both cash settlements and non-cash changes in fair value, are included in earnings with a corresponding increase or decrease in the Consolidated Balance Sheets fair value amounts.

Our natural gas and oil derivative instruments are comprised of swap and call option contracts. Swap contracts allow us to receive a fixed price and pay a floating market price to the counterparty for the hedged commodity. In the second quarter of 2012, we entered into additional swap contracts and sold call options to certain counterparties. Call options are financial contracts that give our trading counterparties the right, but not the obligation to buy an agreed quantity of natural gas from us at a certain time and price in the future. At the time of settlement, if the market price exceeds the fixed price of the call option, we pay the counterparty the excess. If the market price settles below the fixed price of the call option, no payment is due from either party. In exchange for selling this option, we received upfront proceeds which we used to obtain a higher fixed price on our swaps.

We place our derivative financial instruments with the financial institutions that are lenders under the EXCO Resources Credit Agreement that we believe have high quality 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.

The following table presents the volumes and fair value of our oil and natural gas derivative financial instruments as of December 31, 2012:

(in thousands, except prices)	Volume Mmbtus/Bbls	Weighted average strike price per Mmbtu/Bbl	Fair value at December 31, 2012
Natural gas:			
Swaps:			
2013	71,175	$ 4.21	$ 46,929
2014	56,575	4.26	12,670
2015	28,288	4.31	2,392
Calls:			
2013	20,075	$ 4.29	$ (2,265)
2014	20,075	4.29	(7,632)
2015	20,075	4.29	(11,409)
Total natural gas	216,263		$ 40,685
Oil:			
Swaps:			
2013	365	$ 99.96	$ 2,443
Calls:			
2013	—	$ —	$ —
2014	365	100.00	(2,768)
2015	365	100.00	(3,071)
Total oil	1,095		$ (3,396)
Total oil and natural gas derivatives			$ 37,289

At December 31, 2011, we had outstanding derivative contracts to mitigate price volatility covering 85,995,000 Mmbtus of natural gas and 275 Mbbls of oil. At December 31, 2012, the average forward NYMEX oil prices per Bbl for the calendar years 2013, 2014 and 2015 were $93.22, $92.16 and $90.02, respectively, and the average forward NYMEX natural gas prices per Mmbtu for the calendar years 2013, 2014 and 2015 were $3.54, $4.03 and $4.23, respectively. Upon formation of the EXCO/HGI Partnership, we assigned certain derivative instruments that were outstanding as of December 31, 2012. These derivative instruments covered natural gas production in 2013 of 30,000 Mmbtus per day at an average price of $3.92 per Mmbtu, and covered natural gas production in 2014 of 10,000 Mmbtus per day at an average price of $4.24 per Mmbtu. The fair value of the derivative instruments assigned to the EXCO/HGI Partnership was an unrealized gain of $4.9 million as of December 31, 2012.

Our derivative financial instruments covered approximately 44.0% and 58.9% of production volumes for the years ended December 31, 2012 and 2011, respectively.

5. Fair value measurements

We value our derivatives according to FASB ASC 820, *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 categorize 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.

Fair value of derivative financial instruments

The following table presents a summary of the estimated fair value of our derivative financial instruments as of December 31, 2012 and 2011. During the years ended December 31, 2012 and 2011 there were no changes in the fair value level classifications.

	December 31, 2012			
(in thousands)	**Level 1**	**Level 2**	**Level 3**	**Total**
Oil and natural gas derivative financial instruments	$ —	$ 37,289	$ —	$ 37,289

	December 31, 2011			
(in thousands)	**Level 1**	**Level 2**	**Level 3**	**Total**
Oil and natural gas derivative financial instruments	$ —	$ 173,236	$ —	$ 173,236

We evaluate derivative assets and liabilities in accordance with master netting agreements with the derivative counterparties, but report them on a gross basis 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.

The valuation of our commodity price derivatives, represented by oil and natural gas swaps, is discussed below.

Oil derivatives. Our oil derivatives are swap and call option contracts for notional Bbls of oil at fixed (in the case of swap contracts) or interval (in the case of call option contracts) NYMEX West Texas Intermediate, or 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, and (iv) the implied rate of volatility inherent in the call option contracts. The implied rates of volatility were determined based on average WTI oil prices.

Natural gas derivatives. Our natural gas derivatives are swap and call option contracts for notional Mmbtus of gas at posted price indexes, including NYMEX Henry Hub, or HH, swap and call option 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 natural gas swaps, and (iii) the applicable credit-adjusted risk-free rate curve, as described above and (iv) the implied rate of volatility inherent in the call option contracts. The implied rates of volatility were determined based on average HH natural gas prices.

See further details on the fair value of our derivative financial instruments in "Note 4. Derivative financial instruments."

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 our EXCO Resources Credit Agreement approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to us for those periods.

The estimated fair value of our 7.5% senior unsecured notes due September 15, 2018, or the 2018 Notes, for the years ended December 31, 2012 and December 31, 2011 are presented below. The estimated fair value of the 2018 Notes has been calculated based on market quotes.

(in thousands)	December 31, 2012 Level 1	Level 2	Level 3	Total
2018 Notes	$ 716,250	$ —	$ —	$ 716,250

(in thousands)	December 31, 2011 Level 1	Level 2	Level 3	Total
2018 Notes	$ 705,000	$ —	$ —	$ 705,000

6. Long-term debt

Our total debt is summarized as follows:

(in thousands)	December 31, 2012	December 31, 2011
EXCO Resources Credit Agreement	$ 1,107,500	$ 1,147,500
2018 Notes	750,000	750,000
Unamortized discount on 2018 Notes	(8,528)	(9,672)
Total debt	$ 1,848,972	$ 1,887,828

Terms and conditions of each of these debt obligations are discussed below.

EXCO Resources Credit Agreement

As of December 31, 2012, the EXCO Resources Credit Agreement had a borrowing base of $1.3 billion, with $1.1 billion of outstanding indebtedness and $185.4 million of available borrowing capacity. On December 31, 2012, the one month LIBOR was 0.2%, which would result in an interest rate of approximately 2.7%. The borrowing base is redetermined semi-annually, with us and the lenders having the right to request interim unscheduled redeterminations in certain circumstances. On April 27, 2012, we entered into the Sixth Amendment to the EXCO Resources Credit Agreement in conjunction with the regular semi-annual redetermination of the borrowing base and established the borrowing base at $1.4 billion, with an interest grid of LIBOR plus 175 bps to 275 bps (or ABR plus 75 bps to 175 bps). Our consolidated funded debt to consolidated EBITDAX covenant, as defined in the agreement, increased to 4.5 to 1.0 from 4.0 to 1.0, effective at the end of any fiscal quarter ending on or after March 31, 2012. On October 30, 2012, we entered into the Seventh Amendment to the EXCO Resources Credit Agreement, which established our borrowing base at $1.3 billion. There were no changes to the interest grid or covenants. Upon formation of the EXCO/HGI Partnership, as discussed in Note 18. Subsequent Events, we used the proceeds of $573.3 million to pay down the EXCO Resources Credit Agreement and the borrowing base was reduced to $900.0 million. The maturity date of the EXCO Resources Credit Agreement is April 1, 2016.

The majority of our subsidiaries are guarantors under the EXCO Resources Credit Agreement. The EXCO Resources Credit Agreement permits investments, loans and advances to the unrestricted subsidiaries related to our joint ventures with certain limitations, and allows us to repurchase up to $200.0 million of our common stock, of which $7.5 million has been repurchased as of December 31, 2012. Unless otherwise permitted, any cash balances of non-guarantor subsidiaries or unconsolidated joint ventures are not security for the EXCO Resources Credit Agreement.

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 agreement, in our oil and natural gas properties covered by the 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 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 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 our borrowing base available under the EXCO Resources Credit Agreement, and (iii) payment of such dividend is permitted under the indenture governing the 2018 Notes.

As of December 31, 2012, 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 EXCO Resources Credit 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 to consolidated EBITDAX (as defined in the EXCO Resources Credit Agreement) to be greater than 4.5 to 1.0 at the end of any fiscal quarter ending on or after March 31, 2012.

While we believe our existing capital resources, including our cash flow from operations and borrowing capacity under the EXCO Resources Credit Agreement is sufficient to conduct our operations through 2013, there are certain risks arising from depressed natural gas prices and production volumes that could impact our ability to meet debt covenants in future periods. In particular, our consolidated funded indebtedness to consolidated EBITDAX, as defined in the EXCO Resources Credit Agreement, is computed using the trailing twelve month EBITDAX and only includes operations from non-guarantor subsidiaries and unconsolidated joint ventures to the extent that cash is distributed to entities under the EXCO Resources Credit Agreement. As a result, our ability to maintain compliance with this covenant may be negatively impacted when oil and/or natural gas prices decline for an extended period of time.

In response to the declines in natural gas prices, we have reduced our drilling plans which will result in lower expected production volumes during 2013, and we have reduced operating and administrative expenses. The combination of our reduced borrowing base, lower production volumes and the expiration of higher priced derivative financial instruments may require us to seek alternative financing arrangements, further reduce costs including drilling activity, or sell assets.

2018 Notes

The 2018 Notes are guaranteed on a senior unsecured basis by a majority of EXCO's subsidiaries, with the exception of certain non-guarantor subsidiaries and 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, 2012, $750.0 million in principal was outstanding on the 2018 Notes. The unamortized discount on the 2018 Notes at December 31, 2012 was $8.5 million. Interest accrues at 7.5% and is payable semi-annually in arrears on March 15th and September 15th 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.

The indenture governing our 2018 Notes also contains a debt incurrence test on secured borrowings based on (i) the greater of $1.2 billion, subject to certain permanent reductions, or (ii) 75% of adjusted consolidated net tangible assets, or ACNTA, as defined in the indenture governing the 2018 Notes. A significant component of the ACNTA valuation is based on the PV-10 value of our Proved Reserves, computed using SEC pricing as of the beginning of each year. On January 1, 2012, the ACNTA limitation was $2.1 billion. Due primarily to a significant reduction in our PV-10 at December 31, 2012, the ACNTA limitation was reduced to $1.1 billion on January 1, 2013. While ACNTA limits our ability to incur secured indebtedness, we may incur unsecured indebtedness in excess of the ACNTA limitation to the extent such indebtedness is otherwise permitted under the indenture.

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

7. 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.

8. Commitments and contingencies

We lease our offices and certain equipment. Our rental expenses were approximately $6.8 million, $8.2 million and $8.2 million for the years ended December 31, 2012, 2011 and 2010, respectively. Our future minimum rental payments under operating leases with remaining non-cancellable lease terms at December 31, 2012, are presented on the following table. The commitments do not include those of our equity method investments.

(in thousands)	Firm transportation services	Other fixed commitments	Drilling contracts	Operating leases and other	Total
2013	$ 92,872	$ 12,160	$ 10,854	$ 16,058	$ 131,944
2014	92,576	6,539	—	7,449	106,564
2015	92,240	6,374	—	4,598	103,212
2016	89,509	5,879	—	1,151	96,539
2017	89,060	898	—	—	89,958
Thereafter	279,738	—	—	—	279,738
Total	$ 735,995	$ 31,850	$ 10,854	$ 29,256	$ 807,955

We have entered into firm transportation agreements with pipeline companies to facilitate sales from our Haynesville shale production and report these firm transportation costs as a component of gathering and transportation expenses. At the end of 2012, our firm transportation agreements covered an average of 811 Mmcf per day through 2015, with average annual minimum gathering and transportation expenses of approximately $92.6 million per year. For the years 2016 through 2021, our firm transportation agreements range from covering an average of 738 Mmcf per day in 2016 and trend down to 400 Mmcf per day in 2021, with average annual minimum gathering and transportation expenses ranging from approximately $89.5 million per year in 2016 and trending down to $48.9 million in 2021.

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 reserved our estimated exposure and do not believe it was material 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 estimable.

9. Employee benefit plans

At December 31, 2012, we sponsored a 401(k) plan for our employees and matched 100% of employee contributions. Our matching contributions were $9.4 million, $9.4 million and $7.8 million for the years ended December 31, 2012, 2011 and 2010, respectively.

10. Earnings per share

We account for earnings per share in accordance with FASB ASC 260-10, *Earnings Per Share.* ASC 260-10 requires companies to present two calculations of EPS: basic and diluted. Basic EPS for the years ended December 31, 2012, 2011 and 2010 equals the net income divided by the weighted average common shares outstanding during the periods. Weighted average common shares outstanding is equal to the weighted average of all shares outstanding for the period, excluding restricted stock awards. Diluted EPS for the years ended December 31, 2012, 2011 and 2010 are computed in the same manner as basic earnings per share after assuming the issuance of common stock for all potentially dilutive common stock equivalents, which include both stock options and restricted stock awards, whether exercisable or not. The computation of diluted EPS excluded 17,242,306, 7,251,289 and 4,099,255 antidilutive common share equivalents for the years ended December 31, 2012, 2011 and 2010, respectively.

The following table presents the basic and diluted earnings (loss) per share computations for the years ended December 31, 2012, 2011 and 2010 :

	Years Ended December 31,		
(in thousands, except per share data)	**2012**	**2011**	**2010**
Basic net income per common share:			
Net income (loss)	$ (1,393,285)	$ 22,596	$ 671,926
Weighted average common shares outstanding	214,321	213,908	212,465
Net income (loss) per basic common share	$ (6.50)	$ 0.11	$ 3.16
Diluted net income per common share:			
Net income (loss)	$ (1,393,285)	$ 22,596	$ 671,926
Weighted average common shares outstanding	214,321	213,908	212,465
Dilutive effect of:			
Stock options	—	2,797	3,270
Restricted shares	—	—	—
Weighted average common and common equivalent shares outstanding	214,321	216,705	215,735
Net income (loss) per diluted common share	$ (6.50)	$ 0.10	$ 3.11

11. Stock options and awards

Description of plan

As of December 31, 2012 and 2011, there were 2,682,249 and 2,670,634 shares, respectively, available for issuance under the 2005 Incentive Plan. Under the plan we grant both options and restricted stock. Option grants count as one share against the total number of shares we have available for grant and restricted stock grants count as 1.17 shares for awards granted before October 6, 2011 and 2.1 shares for awards granted after October 6, 2011. The holders of restricted stock have voting rights and upon vesting the right to receive all accrued and unpaid dividends.

Compensation costs

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

Total share-based compensation to be recognized on unvested options and restricted stock awards as of December 31, 2012 was $23.7 million. Of this amount, $5.4 million related to unvested options will be recognized over a weighted average period of 1.4 years and $18.3 million related to unvested restricted stock awards will be recognized over a weighted average period of 3.1 years.

The following is a reconciliation of our share-based compensation expense for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
(in thousands)	**2012**	**2011**	**2010**
General and administrative expense	$ 8,926	$ 10,872	$ 15,800
Lease operating expense	—	140	1,041
Total share-based compensation expense	8,926	11,012	16,841
Share-based compensation capitalized	7,513	6,406	6,351
Total share-based compensation	$ 16,439	$ 17,418	$ 23,192

The total tax benefit attributable to our share-based compensation for the years ended December 31, 2012, 2011 and 2010 was $0.0 million, $1.2 million and $1.3 million, respectively.

Stock options

Our outstanding stock option expiration dates range from 5 to 10 years following the date of grant and have a weighted average remaining life of 4.8 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.

The following table summarizes stock option activity related to our employees under the 2005 Incentive Plan for the years ended December 31, 2012, 2011 and 2010:

	Stock Options	Weighted average exercise price per share	Weighted average remaining terms (in years)	Aggregate intrinsic value
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		
Granted	831,600	11.79		
Forfeitures	698,700	17.88		
Exercised	941,658	12.81		
Options outstanding at				
December 31, 2011	15,670,168	13.44		
Granted	146,500	8.00		
Forfeitures	1,543,933	16.12		
Exercised	256,940	7.66		
Options outstanding at				
December 31, 2012	14,015,795	$ 13.20	4.82	$ —
Options exercisable at				
December 31, 2012	13,144,246	$ 13.11	4.69	$ —

The weighted average fair value of stock options on the date of the grant during the years ended December 31, 2012, 2011 and 2010 were $3.96, $5.92 and $10.19, respectively. The total intrinsic value of stock options exercised for the years ended December 31, 2012, 2011 and 2010 was $0.1 million, $6.0 million and $11.3 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 above:

	2012	2011	2010
Expected life	3.8 to 7.5 years	3.8 to 7.5 years	7.5 years
Risk-free rate of return	0.56 - 1.64 %	0.67 - 3.09 %	2.04 - 3.52%
Volatility	57.34 - 60.24%	55.77 - 72.83%	54.37 - 56.80%
Dividend yield	0.52 - 1.92%	0.77 - 1.51%	0.45 - 1.15%

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.

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 the 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 per share and the exercise prices of the options accelerated ranged from $7.50 to $24.66 per share.

Restricted stock

Shares are valued at the closing price of our stock on the date of grant. Shares vest over a range of three to five years.

A summary of our restricted stock activity for the years ended December 31, 2012 and 2011 are as follows:

	Shares	Weighted average grant date fair value per share	
Non-vested shares outstanding at December 31, 2010	—	$	—
Granted	2,589,709		11.75
Vested	—		—
Forfeited	(27,300)		14.71
Non-vested shares outstanding at December 31, 2011	2,562,409	$	11.72
Granted	926,900		7.57
Vested	(370,448)		12.89
Forfeited	(312,496)		11.89
Non-vested shares outstanding at December 31, 2012	2,806,365	$	10.16

12. Income taxes

The income tax provision attributable to our income (loss) before income taxes for the years ended December 31, 2012, 2011 and 2010, consisted of the following:

	Years ended December 31,					
(in thousands)	**2012**		**2011**		**2010**	
Current:						
Federal	$	—	$	—	$	1,348
State		—		—		260
Total current income tax (benefit)	$	—	$	—	$	1,608
Deferred:						
Federal	$	(485,543)	$	10,111	$	248,132
State		(59,406)		1,554		29,050
Valuation allowance		544,949		(11,665)		(277,182)
Total deferred income tax (benefit)		—		—		—
Total income tax (benefit)	$	—	$	—	$	1,608

We have net operating loss carryforwards, or NOLs, for United States income tax purposes that have been generated from our operations. Our NOLs are scheduled to expire if not utilized between 2026 and 2032. NOL and alternative minimum tax credits available for utilization as of December 31, 2012 were approximately $1.5 billion and $1.5 million, respectively.

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, 2012	December 31, 2011
Current deferred tax asset (liabilities):		
Derivative financial instruments	$ —	$ —
Other	152	242
Valuation allowance	(152)	(242)
Net current deferred tax assets (liabilities)	—	—
Non-current deferred tax assets:		
Net operating loss and AMT credits carryforwards	$ 604,437	$ 657,922
Share-based compensation	11,173	9,003
Depletion, depreciation and amortization	398,350	—
Goodwill	6,291	10,524
Other	85	85
Total non-current deferred tax assets	1,020,336	677,534
Valuation allowance	(919,986)	(375,281)
Total non-current deferred tax assets	100,350	302,253
Non-current deferred tax liabilities:		
Depletion, depreciation and amortization	$ (4,931)	$ (185,551)
Investments in partnerships	(80,825)	(59,336)
Derivative financial instruments	(14,594)	(57,366)
Total non-current deferred tax liabilities	(100,350)	(302,253)
Net 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, 2012, 2011 and 2010 is presented in the following table:

	Years Ended December 31,		
(in thousands)	2012	2011	2010
Federal income taxes (benefit) provision at statutory rate of 35%	$ (487,649)	$ 7,909	$ 235,737
Increases (reductions) resulting from:			
Goodwill	—	—	11,556
Adjustments to the valuation allowance	544,949	(11,665)	(277,182)
Non-deductible compensation	1,893	1,760	2,098
State taxes net of federal benefit	(59,406)	1,554	29,050
Other	213	442	349
Total income tax provision	$ —	$ —	$ 1,608

During 2012, our income was greatly impacted by the ceiling test write-downs and the recognized valuation allowance almost completely offset the write-downs. There were no material sales transactions during the year to impact taxable income. The net result was no income tax provision for 2012.

During 2011, our taxable income was offset by utilization of net operating losses and a corresponding decrease to previously recognized valuation allowances against deferred tax assets. The net result was no income tax provision for 2011.

During 2010, our taxable income was impacted by gains attributable to the formation of the Appalachia JV, offset by utilization of net operating losses and a corresponding decrease to previously recognized valuation allowances against deferred tax assets. The 2010 income tax provision represents an alternative minimum tax and state income tax liability.

We adopted the provisions of FASB ASC 740-10, *Income Taxes,* on January 1, 2007. As a result of the implementation of ASC 740-10, the Company did not recognize any liabilities for unrecognized tax benefits. As of December 31, 2012, 2011 and 2010, 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 consolidated financial statements.

We file income tax returns in the U.S. federal jurisdictions and various state jurisdictions. With few exceptions, we are no longer subject to U.S. federal and state and local examinations by tax authorities for years before 2004. We are not currently under examination by the Internal Revenue Service.

13. Related party transactions

Corporate use of personal aircraft

We have periodically chartered, for company business, an 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 the aircraft from DHM Aviation, LLC. We believe that prudent use of a chartered private airplane by our senior management while on company business can promote efficient use of management time. Such usage can allow for unfettered, confidential communications among management during the course of the flight and minimize airport commuting and waiting time, thereby promoting maximum use of management time for company business. However, we restrict the use of the aircraft to priority company business being conducted by senior management in a manner that is cost effective 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 the performance of senior management's jobs. Such use must be approved in advance by our Chief Executive Officer, President and Chief Financial Officer, Chief Operating Officer or General Counsel. 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 in the Dallas, Texas area and other parts of the country to ascertain hourly flight and hourly fuel surcharge rates for aircrafts of comparable size and equipment in relation to the aircraft. A summary of the survey results 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 by us for customary out-of-pocket catering expenses invoiced for a flight and any out-of-pocket expenses incurred by the pilots.

For the years ended December 31, 2012, 2011 and 2010, expenses incurred by EXCO that were payable directly to DHM Aviation, LLC or indirectly through an invoicing agent for use of the aircraft equaled \$0.5 million, \$0.3 million and \$1.1 million, respectively.

TGGT and OPCO

TGGT provides us with gathering, treating and well connection services in the ordinary course of business. In addition, TGGT also purchases natural gas from us in certain areas. OPCO serves as the operator of our wells in the Appalachia JV. There are service agreements between us and TGGT and OPCO whereby we provide administrative and technical services for which we are reimbursed. For the years ended December 31, 2012, 2011 and 2010 these transactions included the following:

	Years Ended December 31,					
	2012		2011		2010	
(in thousands)	TGGT	OPCO	TGGT	OPCO	TGGT	OPCO (2)
Amounts paid:						
Gathering, treating and well connection fees (1)	$ 218,902		$ 199,449		$ 90,115	
Advances to operator		$ 76,729		$ 69,111		$ 47,337
Amounts received:						
Natural gas purchases	$ 15,340		$ 27,948		$ 33,127	
General and administrative services	18,258	$ 52,206	15,730	$ 47,337	11,326	$ 22,635
Purchase of gathering and other assets	—		3,422		5,000	
Other	1,905		2,147		—	
Total	$ 35,503	$ 52,206	$ 49,247	$ 47,337	$ 49,453	$ 22,635

(1) Represents the gross billings from TGGT.
(2) OPCO began providing services to us in June 2010.

As of December 31, 2012 and December 31, 2011, the amounts owed under the service agreements were as follows:

	December 31, 2012		December 31, 2011	
(in thousands)	TGGT	OPCO	TGGT	OPCO
Amounts due to EXCO	$ 2,483	$ 2,956	$ 8,236	$ 8,178
Amounts due from EXCO (1)	12,540	—	39,422	—

(1) OPCO is the operator of our wells in the Appalachia JV, and we advance funds to OPCO on an as needed basis, which are included in "Other current assets" on our Consolidated Balance Sheets. Any amounts we owe are netted against the advance until the advances are utilized. If the advances are fully utilized, we record amounts owed in "Accounts payable and accrued liabilities" on our Consolidated Balance Sheets.

Other

Until January 1, 2012, Jeff Smith, the son of Stephen F. Smith, our President, Chief Financial Officer and one of our directors, owned a 50% interest in S&S Directional Drilling, LLC, or S&S. Several of TGGT's vendors or their affiliates subcontracted with S&S in 2011 to provide equipment for shallow pipe-line construction directional drilling services. From January 1, 2011 through December 31, 2011, S&S was paid approximately $3.8 million by these vendors and/or their affiliates for the use of equipment in connection with services provided to TGGT. On January 1, 2012, EXCO's preferred service provider in East Texas and Louisiana purchased 100% of the membership interests of S&S, including the 50% interest owned by Mr. Smith's son, or the S&S Transaction. As a result of the S&S Transaction, S&S became a direct vendor of TGGT and EXCO and their preferred service provider for pipe-line construction directional drilling in East Texas and Louisiana. During 2010, S&S was paid approximately $6.9 million, by one of EXCO's vendors or its affiliates for the usage of equipment in connection with services provided to EXCO.

Penny Wilson, the spouse of Mark E. Wilson, our Vice President, Chief Accounting Officer and Controller, was retained by us during 2010 and 2011 as a consultant to support certain marketing and operational functions. Fees paid to Ms. Wilson totaled approximately $0.1 million during 2010 and were not material during 2011. There were no fees paid to Ms. Wilson in 2012.

Kyle Hickey, the son of Harold L. Hickey, our Vice President and Chief Operating Officer, was retained by us as a consultant during 2010 and 2011 primarily to support land functions and became one of our employees in May 2011. During 2012 and 2011, fees paid to Mr. Kyle Hickey totaled approximately $0.1 million and $0.1 million, respectively, and were not material in 2010.

14. Segment information

We follow FASB ASC 280, *Segment Reporting*, or ASC 280, when reporting operating segments. Pursuant to ASC 280, our reportable segments consist of exploration and production and midstream. The exploration and production segment is responsible for acquisition, development and production of oil and natural gas. The midstream segment, which consists of

TGGT and the Appalachia Midstream JV, is accounted for using the equity method and is responsible for purchasing, gathering, transporting and treating natural gas. Our management evaluates TGGT's and the Appalachia Midstream JV's performance on a stand alone basis. The revenues and expenses used to compute the midstream's segment profit represent TGGT's and Appalachia Midstream's results of operations without regard to our 50% ownership. Since we use the equity method of accounting for TGGT and the Appalachia Midstream JV, we eliminate these revenues and expenses when reconciling to our consolidated results of operations and report our net share of midstream's operations as equity income (loss). See "Note. 15—Equity investments" for additional details related to our equity investments, including our midstream segment.

We evaluate the performance of our operating segments based on segment profits, which include segment revenues, excluding the gain (loss) on derivative financial instruments, from external and internal customers and direct segment costs and expenses. Segment profit excludes items such as income taxes, interest income, interest expense, corporate expenses, write-down of oil and natural gas properties, depreciation and depletion and other items.

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

(in thousands)	Exploration and production	Midstream	Equity investee and intercompany eliminations	Consolidated total
For the year ended December 31, 2012:				
Third party revenues	$ 546,609	$ 253,586	$ (253,586)	$ 546,609
Intersegment revenues	—	—	—	—
Total revenues	$ 546,609	$ 253,586	$ (253,586)	$ 546,609
Segment profit	$ 339,124	$ 183,904	$ (183,904)	$ 339,124
Equity income (loss)	$ 1,147	$ 27,473	$ —	$ 28,620
For the year ended December 31, 2011:				
Third party revenues	$ 754,201	$ 242,366	$ (242,366)	$ 754,201
Intersegment revenues	—	—	—	—
Total revenues	$ 754,201	$ 242,366	$ (242,366)	$ 754,201
Segment profit	$ 558,679	$ 134,250	$ (134,250)	$ 558,679
Equity income (loss)	$ (494)	$ 33,200	$ —	$ 32,706
For the year ended December 31, 2010:				
Third party revenues	$ 515,226	$ 160,039	$ (160,039)	$ 515,226
Intersegment revenues	—	—	—	—
Total revenues	$ 515,226	$ 160,039	$ (160,039)	$ 515,226
Segment profit	$ 352,165	$ 63,524	$ (63,524)	$ 352,165
Equity income (loss)	$ (860)	$ 16,882	$ —	$ 16,022
As of December 31, 2012				
Capital expenditures	$ 501,847	$ 134,167	$ (134,167)	$ 501,847
Goodwill	$ 218,256	$ —	$ —	$ 218,256
Total assets	$ 2,323,732	$ 1,254,217	$ (1,254,217)	$ 2,323,732
As of December 31, 2011				
Capital expenditures	$ 1,001,206	$ 284,288	$ (284,288)	$ 1,001,206
Goodwill	$ 218,256	$ —	$ —	$ 218,256
Total assets	$ 3,791,587	$ 1,255,977	$ (1,255,977)	$ 3,791,587

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

	Years Ended December 31,		
(in thousands)	2012	2011	2010
Segment profits	$ 339,124	$ 558,679	$ 352,165
Depletion, depreciation and amortization	(303,156)	(362,956)	(196,963)
Write-down of oil and natural gas properties	(1,346,749)	(233,239)	—
Accretion of discount on asset retirement obligations	(3,887)	(3,652)	(3,758)
General and administrative	(83,818)	(104,618)	(105,114)
Gain (loss) on divestitures and other operating items	(17,029)	(23,819)	509,872
Interest expense	(73,492)	(61,023)	(45,533)
Gain on derivative financial instruments	66,133	219,730	146,516
Other income	969	788	327
Equity income	28,620	32,706	16,022
Income (loss) before income taxes	$ (1,393,285)	$ 22,596	$ 673,534

15. Equity investments

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

- We have a 50% ownership in TGGT, which holds interests in midstream assets in East Texas and North Louisiana. In 2012, TGGT recorded an impairment of approximately $34.9 million of certain assets (approximately $17.4 million net to us) associated with the installation of temporary treating facilities in response to an incident at a TGGT amine treating facility in May 2011. After completion of an independent engineering study, the decision was made to activate the permanent facility affected by the incident since that facility had not sustained as much damage as was initially contemplated. The impairment primarily resulted from costs incurred related to temporary treating facilities that were not utilized or determined to have a shorter utilization period than originally anticipated. In addition, lower than expected throughput volumes at the facility as a result of reduced drilling contributed to the impairment. During the year ended December 31, 2012, EXCO and BG Group each contributed $0.6 million in assets to TGGT.

- We own a 50% interest in OPCO, which operates the Appalachia JV properties, subject to oversight from a management board having equal representation from EXCO and BG Group. During the year ended December 31, 2012, EXCO and BG Group each contributed $14.9 million to OPCO, which is equal to OPCO's 0.5% interest in any property acquisitions and the capital contributions for OPCO's drilling, facilities and operating budget requirements.

- We own a 50% interest in the Appalachia Midstream JV, through which we and BG Group will pursue the construction and expansion of gathering systems for anticipated future production from the Marcellus shale.

- We own a 50% interest in an entity that manages certain surface acreage.

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, 2012	December 31, 2011
Assets		
Total current assets	$ 151,098	$ 227,911
Property and equipment, net	1,228,231	1,173,642
Other assets	6,408	6,570
Total assets	$ 1,385,737	$ 1,408,123
Liabilities and members' equity		
Total current liabilities	$ 120,408	$ 256,794
Total long term liabilities	492,071	462,669
Members' equity:		
Total members' equity	773,258	688,660
Total liabilities and members' equity	$ 1,385,737	$ 1,408,123

	Years Ended December 31,		
(in thousands)	2012	2011	2010
Revenues:			
Oil and natural gas	$ 456	$ 524	$ 168
Midstream	253,586	242,366	160,039
Total revenues	254,042	242,890	160,207
Costs and expenses:			
Oil and natural gas production	234	55	268
Midstream operating	69,682	108,116	96,515
Write-down of oil and natural gas properties	1,230	1,445	1,147
Asset impairments, net of insurance recoveries	50,771	9,688	—
General and administrative	24,593	19,597	15,493
Depletion, depreciation and amortization	40,570	28,482	18,226
Other expenses (income)	13,049	13,211	(244)
Total costs and expenses	200,129	180,594	131,405
Income before income taxes	53,913	62,296	28,802
Income tax expense	425	636	288
Net income	$ 53,488	$ 61,660	$ 28,514
EXCO's share of equity income before amortization	$ 26,744	$ 30,830	$ 14,257
Amortization of the difference in the historical basis of our contribution	$ 1,876	$ 1,876	$ 1,765
EXCO's share of equity income after amortization	$ 28,620	$ 32,706	$ 16,022

(in thousands)	December 31, 2012	December 31, 2011
Equity investments	$ 347,008	$ 302,833
Basis adjustment (1)	45,755	45,755
Cumulative amortization of basis adjustment (2)	(6,134)	(4,258)
EXCO's 50% interest in equity investments	$ 386,629	$ 344,330

(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.

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

16. Dividends

On November 28, 2012, our board of directors approved a cash dividend of $0.04 per share for the fourth quarter of 2012. The total cash dividend was $8.7 million of which $8.6 million was paid on December 28, 2012 to holders of record on December 14, 2012 and $0.1 million was accrued to be paid to restricted shareholders when their shares vest. Total dividends paid to our shareholders in 2012 were $34.7 million, of which $0.3 million was accrued and will be paid to restricted shareholders when their shares vest.

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, the indenture governing the 2018 Notes and the approval of our board of directors.

17. 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 is conducted in compliance with the Rule 10b-18 under the Exchange Act and applicable legal requirements and is 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, 2012, we have repurchased a total of 539,221 shares for $7.5 million at an average price of $13.87 per share.

18. Subsequent events

On February 14, 2013, we formed a private partnership with HGI. Pursuant to the agreements governing the transaction, we contributed our conventional non-shale assets in East Texas and North Louisiana and our shallow Canyon Sand and other assets in the Permian Basin of West Texas to the EXCO/HGI Partnership, in exchange for approximately $573.3 million of cash, after customary preliminary purchase price adjustments, and a 25.5% economic interest in the partnership. HGI contributed cash to us in the amount of approximately $348.3 million. The remaining proceeds we received were in the form of a cash distribution from the partnership of $225.0 million from a draw on the EXCO/HGI Partnership Credit Agreement discussed below. Upon closing, HGI's economic interest in the EXCO/HGI Partnership is 74.5% and our economic interest is 25.5%. The primary strategy of the EXCO/HGI Partnership will be to acquire conventional producing oil and gas properties to enhance asset value and cash flow.

In connection with its formation, the EXCO/HGI Partnership entered into the EXCO/HGI Partnership Credit Agreement with an initial borrowing base of $400.0 million, of which $230.0 million was drawn at closing. Borrowings under the EXCO/HGI Partnership Credit Agreement are secured by the properties contributed to the EXCO/HGI Partnership and we do not guarantee the EXCO/HGI Partnership's debt. The EXCO/HGI Partnership is not a guarantor to the EXCO Resources Credit Agreement.

Proceeds from the formation of the EXCO/HGI Partnership were used to reduce outstanding borrowings under the EXCO Resources Credit Agreement. As a result of this transaction, our borrowing base under the EXCO Resources Credit Agreement was reduced to $900.0 million.

Immediately following closing, the EXCO/HGI Partnership assumed an agreement to purchase all of the shallow Cotton Valley assets within our joint venture with an affiliate of BG Group, for $132.5 million, subject to customary closing adjustments. A deposit of $25.0 million was paid to BG Group when the agreement was executed. The transaction is expected to close in the first quarter of 2013 and funded with borrowings from the EXCO/HGI Partnership Credit Agreement. In connection with the acquisition of the properties from BG Group, the EXCO/HGI Partnership has requested an increase to the borrowing base under the EXCO/HGI Partnership Credit Agreement.

19. Condensed consolidating financial statements

As of December 31, 2012, the majority of EXCO’s subsidiaries are guarantors under the EXCO Resources Credit Agreement and the indenture governing the 2018 Notes. All of our non-guarantor subsidiaries are considered unrestricted subsidiaries under the indenture governing the 2018 Notes, with the exception of our equity investment in OPCO. As of and for the year ended December 31, 2012:

- Our equity method investment in OPCO represented $17.3 million of equity method investments and contributed $25,000 of equity method losses; and
- Our interests in jointly held entities with BG Group, with the exception of OPCO, represented $329.7 million of equity method investments, or 14.2% of our total assets and contributed $28.6 million of equity method income.

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). For purposes of this footnote, EXCO Resources, Inc. is referred to as Resources to distinguish it from the Guarantor Subsidiaries. Each of the Guarantor Subsidiaries is a wholly-owned subsidiary of Resources and the guarantees are unconditional as they relate to the assets of 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.

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2012

(in thousands)	Resources	Guarantor Subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 65,791	$ (20,147)	$ —	$ —	$ 45,644
Restricted cash	—	70,085	—	—	70,085
Other current assets	63,333	182,804	—	—	246,137
Total current assets	129,124	232,742	—	—	361,866
Equity investments	—	—	347,008	—	347,008
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties and development costs not being amortized	48,179	421,864	—	—	470,043
Proved developed and undeveloped oil and natural gas properties	513,668	2,202,099	—	—	2,715,767
Accumulated depletion	(328,560)	(1,617,005)	—	—	(1,945,565)
Oil and natural gas properties, net	233,287	1,006,958	—	—	1,240,245
Gas gathering, office, field and other equipment, net	7,701	109,490	—	—	117,191
Investments in and advances to affiliates	(549,795)	—	—	549,795	—
Deferred financing costs, net	22,584	—	—	—	22,584
Derivative financial instruments	16,554	—	—	—	16,554
Goodwill	38,100	180,156	—	—	218,256
Other assets	1	27	—	—	28
Total assets	$ (102,444)	$ 1,529,373	$ 347,008	$ 549,795	$ 2,323,732
Liabilities and shareholders' equity					
Current liabilities	$ 37,031	$ 200,900	$ —	$ —	$ 237,931
Long-term debt	1,848,972	—	—	—	1,848,972
Deferred income taxes	—	—	—	—	—
Other long-term liabilities	34,686	52,750	—	—	87,436
Payable to parent	(2,172,526)	2,178,682	(6,156)	—	—
Total shareholders' equity	149,393	(902,959)	353,164	549,795	149,393
Total liabilities and shareholders' equity	$ (102,444)	$ 1,529,373	$ 347,008	$ 549,795	$ 2,323,732

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2011

(in thousands)	Resources	Guarantor Subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 78,664	$ (46,667)	$ —	$ —	$ 31,997
Restricted cash	—	155,925	—	—	155,925
Other current assets	177,709	312,377	—	—	490,086
Total current assets	256,373	421,635	—	—	678,008
Equity investments	—	—	302,833	—	302,833
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties and development costs not being amortized	15,942	651,400	—	—	667,342
Proved developed and undeveloped oil and natural gas properties	464,898	2,927,248	—	—	3,392,146
Accumulated depletion	(327,218)	(1,329,947)	—	—	(1,657,165)
Oil and natural gas properties, net	153,622	2,248,701	—	—	2,402,323
Gas gathering, office, field and other equipment, net	27,815	121,668	—	—	149,483
Investments in and advances to affiliates	869,387	—	—	(869,387)	—
Deferred financing costs, net	29,622	—	—	—	29,622
Derivative financial instruments	5,998	5,036	—	—	11,034
Goodwill	38,100	180,156	—	—	218,256
Other assets	3	25	—	—	28
Total assets	$ 1,380,920	$ 2,977,221	$ 302,833	$ (869,387)	$ 3,791,587
Liabilities and shareholders' equity					
Current liabilities	$ 39,395	$ 248,004	$ —	$ —	$ 287,399
Long-term debt	1,887,828	—	—	—	1,887,828
Deferred income taxes	—	—	—	—	—
Other long-term liabilities	7,740	50,288	—	—	58,028
Payable to parent	(2,112,375)	2,118,531	(6,156)	—	—
Total shareholders' equity	1,558,332	560,398	308,989	(869,387)	1,558,332
Total liabilities and shareholders' equity	$ 1,380,920	$ 2,977,221	$ 302,833	$ (869,387)	$ 3,791,587

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the year ended December 31, 2012

(in thousands)	Resources	Guarantor Subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 78,649	$ 467,960	$ —	$ —	$ 546,609
Costs and expenses:					
Oil and natural gas production	19,820	84,790	—	—	104,610
Gathering and transportation	—	102,875	—	—	102,875
Depreciation, depletion and amortization	7,767	295,389	—	—	303,156
Write-down of oil and natural gas properties	—	1,346,749	—	—	1,346,749
Accretion of discount on asset retirement obligations	526	3,361	—	—	3,887
General and administrative	14,394	69,424	—	—	83,818
Other operating items	(194)	17,223	—	—	17,029
Total costs and expenses	42,313	1,919,811	—	—	1,962,124
Operating income (loss)	36,336	(1,451,851)	—	—	(1,415,515)
Other income (expense):					
Interest expense	(73,489)	(3)	—	—	(73,492)
Gain on derivative financial instruments	62,812	3,321	—	—	66,133
Other income	238	731	—	—	969
Income from equity investments	—	—	28,620	—	28,620
Equity in earnings of subsidiaries	(1,419,182)	—	—	1,419,182	—
Total other income (expense)	(1,429,621)	4,049	28,620	1,419,182	22,230
Income (loss) before income taxes	(1,393,285)	(1,447,802)	28,620	1,419,182	(1,393,285)
Income tax expense	—	—	—	—	—
Net income (loss)	$ (1,393,285)	$ (1,447,802)	$ 28,620	$ 1,419,182	$ (1,393,285)

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the year ended December 31, 2011

(in thousands)	Resources	Guarantor Subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 93,663	$ 660,538	$ —	$ —	$ 754,201
Costs and expenses:					
Oil and natural gas production	19,166	89,475	—	—	108,641
Gathering and transportation	—	86,881	—	—	86,881
Depreciation, depletion and amortization	39,954	322,853	149	—	362,956
Write-down of oil and natural gas properties	—	233,239	—	—	233,239
Accretion of discount on asset retirement obligations	442	3,210	—	—	3,652
General and administrative	27,559	77,059	—	—	104,618
Other operating items	19,122	4,973	(276)	—	23,819
Total costs and expenses	106,243	817,690	(127)	—	923,806
Operating income (loss)	(12,580)	(157,152)	127	—	(169,605)
Other income (expense):					
Interest expense	(59,764)	(1,259)	—	—	(61,023)
Gain on derivative financial instruments	190,043	29,687	—	—	219,730
Other income	316	472	—	—	788
Income from equity investments	—	—	32,706	—	32,706
Equity in earnings of subsidiaries	(95,419)	—	—	95,419	—
Total other income (expense)	35,176	28,900	32,706	95,419	192,201
Income (loss) before income taxes	22,596	(128,252)	32,833	95,419	22,596
Income tax expense	—	—	—	—	—
Net income (loss)	$ 22,596	$ (128,252)	$ 32,833	$ 95,419	$ 22,596

EXCO RESOURCES, INC.

CONDENSED 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
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
Other income (expense)	10,423	(10,096)	—	—	327
Income from equity investments	—	—	16,022	—	16,022
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.

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

For the year ended December 31, 2012

(in thousands)	Resources	Guarantor Subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by operating activities	$ 182,143	$ 332,643	$ —	$ —	$ 514,786
Investing Activities:					
Additions to oil and natural gas properties, gathering systems and equipment	(77,006)	(459,917)	—	—	(536,923)
Restricted cash	—	85,840	—	—	85,840
Equity method investments	—	(14,907)	—	—	(14,907)
Proceeds from disposition of property and equipment	15,161	22,884	—	—	38,045
Distributions from equity method investments	—	—	—	—	—
Deposit on acquisitions	—	—	—	—	—
Net changes in advances (to) from Appalachia JV	—	851	—	—	851
Advances/investments with affiliates	(59,126)	59,126	—	—	—
Other	—	—	—	—	—
Net cash used in investing activities	(120,971)	(306,123)	—	—	(427,094)
Financing Activities:					
Borrowings under the EXCO Resources Credit Agreement	53,000	—	—	—	53,000
Repayments under the EXCO Resources Credit Agreement	(93,000)	—	—	—	(93,000)
Proceeds from issuance of common stock	1,968	—	—	—	1,968
Payment of common stock dividends	(34,358)	—	—	—	(34,358)
Deferred financing costs and other	(1,655)	—	—	—	(1,655)
Net cash used in financing activities	(74,045)	—	—	—	(74,045)
Net increase (decrease) in cash	(12,873)	26,520	—	—	13,647
Cash at beginning of period	78,664	(46,667)	—	—	31,997
Cash at end of period	$ 65,791	$ (20,147)	$ —	$ —	$ 45,644

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

For the year ended December 31, 2011

(in thousands)	Resources	Guarantor Subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by operating activities	$ 71,636	$ 355,736	$ 1,171	$ —	$ 428,543
Investing Activities:					
Additions to oil and natural gas properties, gathering systems and equipment	(63,089)	(1,670,029)	(4,253)	—	(1,737,371)
Restricted cash	—	5,792	—	—	5,792
Equity method investments	—	(13,829)	—	—	(13,829)
Proceeds from disposition of property and equipment	3,129	446,554	—	—	449,683
Distributions from equity method investments	—	125,000	—	—	125,000
Deposit on acquisitions	—	464,151	—	—	464,151
Net changes in advances (to) from Appalachia JV	—	(1,707)	—	—	(1,707)
Advances/investments with affiliates	(278,531)	275,449	3,082	—	—
Other	—	(1,250)	—	—	(1,250)
Net cash used in investing activities	(338,491)	(369,869)	(1,171)	—	(709,531)
Financing Activities:					
Borrowings under the EXCO Resources Credit Agreement	706,000	—	—	—	706,000
Repayments under the EXCO Resources Credit Agreement	(407,500)	—	—	—	(407,500)
Proceeds from issuance of common stock	12,063	—	—	—	12,063
Payment of common stock dividends	(34,238)	—	—	—	(34,238)
Deferred financing costs and other	(7,569)	—	—	—	(7,569)
Net cash provided by financing activities	268,756	—	—	—	268,756
Net increase (decrease) in cash	1,901	(14,133)	—	—	(12,232)
Cash at beginning of period	76,763	(32,534)	—	—	44,229
Cash at end of period	$ 78,664	$ (46,667)	$ —	$ —	$ 31,997

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

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)
Equity method investments	—	(143,740)	—	—	(143,740)
Proceeds from disposition of property and equipment	8,624	1,036,209	—	—	1,044,833
Distributions from equity method investments	—	—	—	—	—
Deposit on acquisitions	—	(464,151)	—	—	(464,151)
Net changes in advances (to) from Appalachia JV	—	(5,017)	—	—	(5,017)
Advances/investments with affiliates	(305,326)	53,247	252,079	—	—
Other	—	—	—	—	—
Net cash provided by (used in) investing activities	(365,180)	(354,278)	6,604	—	(712,854)
Financing Activities:					
Borrowings under the EXCO Resources Credit Agreement	2,022,437	49,962	—	—	2,072,399
Repayments under the EXCO Resources Credit Agreement	(1,945,982)	(24,981)	—	—	(1,970,963)
Proceeds from issuance of 2018 Notes	738,975	—	—	—	738,975
Repayments of 2011 Notes	(444,720)	—	—	—	(444,720)
Proceeds from issuance of common stock	23,024	—	—	—	23,024
Payment of common stock dividends	(29,760)	—	—	—	(29,760)
Payment for common shares repurchased	(7,479)	—	—	—	(7,479)
Settlements of derivative financial instruments with a financing element	(907)	—	—	—	(907)
Deferred financing costs and other	(31,814)	—	—	—	(31,814)
Net cash provided by 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

20. Quarterly financial data (unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2012 and 2011:

	Quarter			
(in thousands, except per share amounts)	1st	2nd	3rd	4th
2012				
Oil and natural gas revenues	$ 134,848	$ 117,978	$ 141,621	$ 152,162
Operating income (loss)	(311,087)	(476,036)	(321,021)	(307,371)
Net income (loss)	$ (281,649)	$ (496,433)	$ (346,174)	$ (269,029)
Basic earnings (loss) per share:				
Net income (loss)	$ (1.32)	$ (2.32)	$ (1.62)	$ (1.25)
Weighted average shares	214,145	214,164	214,301	214,672
Diluted earnings (loss) per share:				
Net income (loss)	$ (1.32)	$ (2.32)	$ (1.62)	$ (1.25)
Weighted average shares	214,145	214,164	214,301	214,672
2011				
Oil and natural gas revenues	$ 161,228	$ 206,828	$ 207,274	$ 178,871
Operating income (loss)	24,631	49,028	4,892	(248,156)
Net income (loss)	$ 21,941	$ 82,362	$ 84,945	$ (166,652)
Basic earnings (loss) per share:				
Net income (loss)	$ 0.10	$ 0.39	$ 0.40	$ (0.78)
Weighted average shares	213,531	213,888	214,068	214,137
Diluted earnings (loss) per share:				
Net income (loss)	$ 0.10	$ 0.38	$ 0.39	$ (0.78)
Weighted average shares	217,110	217,513	216,314	214,137

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

The following supplemental information relating to our oil and natural gas producing activities for the years ended December 31, 2012, 2011 and 2010 is presented in accordance with ASC 932, *Extractive Activities, Oil and Gas.*

Presented below are costs incurred in oil and natural gas property acquisition, exploration and development activities:

(in thousands, except per unit amounts)		Amount
2012:		
Proved property acquisition costs	$	—
Unproved property acquisition costs		3,349
Total property acquisition costs		3,349
Development		346,017
Exploration costs (1)		57,325
Lease acquisitions and other (2)		44,546
Capitalized asset retirement costs		971
Depreciation, depletion and amortization per Boe	$	9.58
Depreciation, depletion and amortization per Mcfe	$	1.60
2011:		
Proved property acquisition costs	$	136,295
Unproved property acquisition costs		260,076
Total property acquisition costs (3)		396,371
Development		593,331
Exploration costs (4)		262,120
Lease acquisitions and other (5)		31,466
Capitalized asset retirement costs		3,765
Depreciation, depletion and amortization per Boe	$	11.92
Depreciation, depletion and amortization per Mcfe	$	1.99
2010:		
Proved property acquisition costs	$	34,042
Unproved property acquisition costs (6)		493,797
Total property acquisition costs		527,839
Development		232,978
Exploration costs (7)		113,617
Lease acquisitions and other (8)		37,518
Capitalized asset retirement costs		1,936
Depreciation, depletion and amortization per Boe	$	10.55
Depreciation, depletion and amortization per Mcfe	$	1.75

(1) Exploration costs in 2012 include approximately $40.1 million in the Haynesville shale, and approximately $17.2 million in the Marcellus shale.
(2) Lease acquisition costs in 2012 are net of acreage reimbursements from BG Group totaling $2.1 million.
(3) Acquisition costs in 2011, net of BG Group reimbursements of $359.1 million, include the Chief Transaction, Appalachia Transaction and the Haynesville Shale Acquisition.
(4) Exploration costs in 2011 include approximately $33.9 million incurred in the Marcellus shale play in Appalachia and approximately $228.2 million in the Shelby area.
(5) Lease acquisition costs in 2011 are net of acreage reimbursements from BG Group totaling $31.9 million.
(6) Reflects acreage acquisitions of Shelby area, DeSoto Parish and Appalachia.
(7) 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 Shelby area.
(8) Lease acquisition costs in 2010 are net of acreage reimbursements from BG Group totaling $58.3 million.

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.

	Oil (Mbbls)	Natural Gas (Mmcf)	Natural Gas Liquids (Mbbls) (11)	Mmcfe
December 31, 2009	5,518	925,728	—	958,836
Purchase of reserves in place	—	30,047	—	30,047
Discoveries and extensions (1)	1,631	635,841	—	645,627
Revisions of previous estimates (2):				
Changes in price	751	48,630	—	53,136
Other factors	549	63,089	—	66,383
Sales of reserves in place (3)	(403)	(140,504)	—	(142,922)
Production	(688)	(107,878)	—	(112,006)
December 31, 2010 (4)	7,358	1,454,953	—	1,499,101
Purchase of reserves in place	—	62,489	—	62,489
Discoveries and extensions (5)	929	195,565	—	201,139
Revisions of previous estimates:				
Changes in price	100	(15,165)	—	(14,565)
Other factors (6)	(1,264)	(222,513)	—	(230,097)
Sales of reserves in place	(28)	(5,599)	—	(5,767)
Production	(741)	(178,266)	—	(182,712)
December 31, 2011 (7)	6,354	1,291,464	—	1,329,588
Purchase of reserves in place	—	—	—	—
Discoveries and extensions (8)	492	96,615	424	102,111
Revisions of previous estimates:				
Changes in price	(110)	(466,238)	—	(466,898)
Other factors (9)	(463)	199,784	6,724	237,350
Sales of reserves in place	—	(2,837)	—	(2,837)
Production	(703)	(182,656)	(509)	(189,928)
December 31, 2012 (10)	5,570	936,132	6,639	1,009,386

Estimated Quantities of Proved Developed Reserves

	Oil (Mbbls)	Natural Gas (Mmcf)	Natural Gas Liquids (Mbbls) (11)	Mmcfe
Proved developed:				
December 31, 2012	4,371	917,326	4,784	972,256
December 31, 2011	4,565	955,522	—	982,912
December 31, 2010	4,633	793,777	—	821,575
Proved undeveloped:				
December 31, 2012	1,199	18,806	1,855	37,130
December 31, 2011	1,789	335,942	—	346,676
December 31, 2010	2,725	661,176	—	677,526

(1) New discoveries and extensions in 2010 include 614,508 Mmcfe in East Texas/North Louisiana, primarily in the Haynesville shale play; 14,699 Mmcfe in Appalachia, of which 10,285 Mmcfe was in the Marcellus shale play; and 16,420 Mmcfe in Permian.

(2) 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.

(3) Sales of reserves in place in 2010 are primarily attributable to the Appalachia JV transaction with BG Group which resulted in the sale of 133,123 Mmcfe.

(4) 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 $405,000, or 0.03%, of our consolidated Standardized Measure.

(5) New discoveries and extensions in 2011 include 158,649 Mmcfe in East Texas/North Louisiana, primarily in the Haynesville shale, 30,206 Mmcfe in Appalachia, all in the Marcellus shale and 12,284 Mmcfe in Permian.

(6) Total revisions due to Other factors in 2011 include approximately 168,264 Mmcfe of Proved Undeveloped Reserves that were reclassified to unproved reserves as a result of a slower development schedule due to continued low natural gas prices, which extended their scheduling beyond a five-year development horizon. The reclassified Proved Developed Reserves represent all non-shale Proved Undeveloped Reserves in Appalachia and East Texas/North Louisiana.

(7) The above reserves do not include our equity interest in OPCO, which represents 0.04% (576 Mmcfe) of our consolidated Proved Reserves at December 31, 2011 and a Standardized Measure of $576,000, or 0.04%, of our consolidated Standardized Measure.

(8) New discoveries and extensions in 2012 include 25,626 Mmcfe in East Texas/North Louisiana, primarily in the Haynesville shale, 59,455 Mmcfe in Appalachia, all in the Marcellus shale and 17,027 Mmcfe in Permian.

(9) Total revisions due to Other factors in 2012 include approximately 8,736 Mmcfe of Proved Undeveloped Reserves that were reclassified to unproved reserves as a result of a slower development schedule due to continued depressed natural gas prices, which extended their scheduled development beyond a five-year development horizon. The change also includes a positive revision of 246,451 Mmcfe resulting from unproved performance and cost reductions.

(10) The above reserves do not include our equity interest in OPCO, which represents 0.07% (752 Mmcfe) of our consolidated Proved Reserves at December 31, 2012 and a Standardized Measure of $458,000, or 0.07% of our consolidated Standardized Measure.

(11) Beginning in 2012, we began reporting our NGLs separately. In 2011 and 2010, the NGLs were reported as a component of natural gas.

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, 2012:		
Future cash inflows	$	3,187,480
Future production costs		1,824,702
Future development costs		266,726
Future income taxes		—
Future net cash flows		1,096,052
Discount of future net cash flows at 10% per annum		399,905
Standardized measure of discounted future net cash flows	$	696,147
Year ended December 31, 2011:		
Future cash inflows	$	5,950,080
Future production costs		2,231,693
Future development costs		915,399
Future income taxes		390,786
Future net cash flows		2,412,202
Discount of future net cash flows at 10% per annum		985,740
Standardized measure of discounted future net cash flows	$	1,426,462
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

During recent years, prices paid for oil and natural gas have fluctuated significantly. The reference prices at December 31, 2012, 2011 and 2010 used in the above table, were $94.71, $96.19 and $79.43 per Bbl of oil, respectively, and $2.76, $4.12 and $4.38 per Mmbtu of natural gas, respectively. Beginning in 2012, we began reporting our NGLs separately. In 2011 and 2010, the NGLs were reported as a component of natural gas. The reference price at December 31, 2012 used in the above table was $46.57 per Bbl for NGLs. In each case, the prices were adjusted for historical differentials. These prices reflect the SEC rules requiring the use of simple average of the first day of the month price for the previous 12 month period for natural gas at Henry Hub, West Texas Intermediate crude oil at Cushing, Oklahoma, and the realized prices for NGLs.

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

(in thousands)	Amount
Year ended December 31, 2012:	
Sales and transfers of oil and natural gas produced	$ (339,125)
Net changes in prices and production costs	(1,258,493)
Extensions and discoveries, net of future development and production costs	90,633
Development costs during the period	204,929
Changes in estimated future development costs	404,414
Revisions of previous quantity estimates (includes revisions-transfer of Proved Undeveloped Reserves to probable reserves)	(336,142)
Sales of reserves in place	(3,604)
Purchase of reserves in place	—
Accretion of discount before income taxes	165,755
Changes in timing and other	94,129
Net change in income taxes	247,189
Net change	$ (730,315)
Year ended December 31, 2011:	
Sales and transfers of oil and natural gas produced	$ (558,794)
Net changes in prices and production costs	(182,750)
Extensions and discoveries, net of future development and production costs	293,377
Development costs during the period	405,125
Changes in estimated future development costs	265,864
Revisions of previous quantity estimates (includes revisions-transfer of Proved Undeveloped Reserves to probable reserves)	(334,181)
Sales of reserves in place	(6,067)
Purchase of reserves in place	156,731
Accretion of discount before income taxes	137,519
Changes in timing and other	140,304
Net change in income taxes	(114,105)
Net change	$ 203,023
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

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	2012	2011	2010	2009 and prior
Property acquisition costs	$ 391,964	$ 47,203	$ 149,390	$ 117,461	$ 77,910
Exploration and development	32,015	32,015	—	—	—
Capitalized interest	46,064	20,486	17,753	7,173	652
Total	$ 470,043	$ 99,704	$ 167,143	$ 124,634	$ 78,562

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, EXCO's 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, 2012 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). Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2012, using criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). 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 control over financial reporting. Prior to December 31, 2012, our management concluded that our disclosure controls and procedures were not effective due to a material weakness related to processes and procedures for the computation of the fair value of our oil and natural gas derivative financial instruments. Management believes that it took the appropriate remediation steps, which included implementing enhanced review and approval controls covering the computation of the fair value computation. Accordingly, management has concluded this material weakness no longer exists. There were no additional changes in EXCO's internal control over financial reporting that occurred during the quarter ended December 31, 2012.

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 SEC pursuant to Regulation 14A of the Exchange Act 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 SEC pursuant to Regulation 14A of the Exchange Act 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 SEC pursuant to Regulation 14A of the Exchange Act 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 SEC pursuant to Regulation 14A of the Exchange Act 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 SEC pursuant to Regulation 14A of the Exchange Act 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.

SIGNATURES

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

EXCO RESOURCES, INC.
(Registrant)

Date: February 21, 2013

/s/ Douglas H. Miller
Douglas H. Miller
Chairman and Chief Executive Officer

/s/ Stephen F. Smith
Stephen F. Smith
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/ 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/ Wilbur L. Ross, Jr.
Wilbur L. Ross, Jr.
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	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 as an Exhibit to EXCO’s Annual Report on Form 10-K for 2010 filed February 24, 2011 and incorporated by reference herein.
2.2	Unit Purchase and Contribution Agreement, dated November 5, 2012, by and among EXCO Resources, Inc., EXCO Operating Company, LP, EXCO/HGI JV Assets, LLC and HGI Energy Holdings, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 5, 2012 and filed on November 9, 2012 and incorporated by reference herein.
3.1	Third Amended and Restated Articles of Incorporation of EXCO Resources, Inc., filed as an Exhibit to EXCO’s Current Report on Form 8-K (File No. 001-32743), 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 (File No. 001-32743), 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 (File No. 001-32743), 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 (File No. 001-32743), 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 (File No. 001-32743), 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 (File No. 001-32743), 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 (File No. 001-32743), 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 (File No. 001-32743), 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.
10.1	Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.2	Form of Incentive Stock Option Agreement for 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 (File No. 001-32743), dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.3	Form of Nonqualified Stock Option Agreement for 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 (File No. 001-32743), dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.4	Form of Restricted Stock Award Agreement for 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 August 4, 2011 and filed on August 10, 2011 and incorporated by reference herein.*
10.5	Fourth Amended and Restated EXCO Resources, Inc. Severance Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 16, 2011 and filed on March 22, 2011 and incorporated by reference herein.*
10.6	Amended and Restated 2007 Director Plan of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.7	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 by reference herein.*
10.8	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 (File No. 001-32743), dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
10.9	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 (File No. 001-32743), dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
10.10	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.*
10.11	Amendment Number Two to the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, dated as of October 6, 2011, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated October 6, 2011 and filed on October 7, 2011 and incorporated by reference herein.*
10.12	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.
10.13	Amendment to Joint Development Agreement, dated February 1, 2011, by and among BG US Production Company, LLC and EXCO Operating Company, LP, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2010 filed February 24, 2011 and incorporated by reference herein.

10.14	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.
10.15	First Amendment to Amended and Restated Limited Liability Company Agreement of TGGT Holdings, LLC, dated January 31, 2011, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2010 filed February 24, 2011 and incorporated by reference herein.
10.16	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.
10.17	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 as an Exhibit to EXCO's Annual Report on Form 10-K for 2010 filed February 24, 2011 and incorporated by reference herein.
10.18	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.
10.19	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.
10.20	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.
10.21	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.
10.22	Performance 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.
10.23	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.
10.24	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.
10.25	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.

10.26	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.
10.27	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.
10.28	Third Amendment to Credit Agreement, dated as of April 1, 2011, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated April 1, 2011 and filed on April 4, 2011 and incorporated by reference herein.
10.29	Fourth Amendment to Credit Agreement, dated as of November 8, 2011, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 8, 2011 and filed on November 9, 2011 and incorporated by reference herein.
10.30	Fifth Amendment to Credit Agreement, dated as of November 8, 2011, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 8, 2011 and filed on November 9, 2011 and incorporated by reference herein.
10.31	Sixth Amendment to Credit Agreement, dated as of April 27, 2012, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2012, filed on May 2, 2012 and incorporated by reference herein.
10.32	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.
10.33	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 as an Exhibit to EXCO's Annual Report on Form 10-K for 2010 filed February 24, 2011 and incorporated by reference herein.
10.34	First Amendment to Credit Agreement, dated January 25, 2012, by and among TGGT Holdings, LLC, TGG Pipeline, Ltd. And Talco Midstream Assets, Ltd., as Borrowers, TGGT GP Holdings, LLC and certain subsidiaries of Borrowers, as Guarantors, JPMorgan Chase Bank, N.A., as Administrative Agent, J.P. Morgan Securities LLC, as Sole Bookrunner and Co-Lead Arranger, Wells Fargo Securities, LLC, Bank of America, N.A., BMO Harris Financing, Inc., Royal Bank of Canada, Morgan Stanley Senior Funding, Inc., UBS Loan Finance LLC and The Royal Bank of Scotland plc, as Co-Lead Arrangers, and the lenders party thereto, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated January 25, 2012 and filed on January 31, 2012 and incorporated by reference herein.
10.35	EXCO Resources, Inc. Retention Bonus Plan, dated August 4, 2011, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 4, 2011 and filed on August 10, 2011 and incorporated by reference herein.*
10.36	Form of Amended and Restated Agreement of Limited Partnership of EXCO/HGI Production Partners, LP, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 5, 2012 and filed on November 9, 2012 and incorporated by reference herein.

10.37	Form of Amended and Restated Limited Liability Company Agreement of EXCO/HGI GP, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 5, 2012 and filed on November 9, 2012 and incorporated by reference herein.
10.38	Letter Agreement, dated November 5, 2012, by and among EXCO Resources, Inc., EXCO Operating Company, LP, Harbinger Group Inc. and HGI Energy Holdings, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 5, 2012 and filed on November 9, 2012 and incorporated by reference herein.
10.39	Seventh Amendment to Credit Agreement, dated as of October 30, 2012, by and among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated October 30, 2012 and filed on November 5, 2012 and incorporated by reference herein.
14.1	Code of Ethics for the Chief Executive Officer and Senior Financial Officers, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed January 6, 2006 and incorporated by reference herein.
14.2	Code of Business Conduct and Ethics for Directors, Officers and Employees, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed January 6, 2006 and incorporated by reference herein.
14.3	Amendment No. 1 to EXCO Resources, Inc. Code of Business Conduct and Ethics for Directors, Officers and Employees, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated November 8, 2006 and filed on November 9, 2006 and incorporated by reference herein.
21.1	Subsidiaries of registrant, filed herewith.
23.1	Consent of KPMG LLP, filed herewith.
23.2	Consent of Lee Keeling and Associates, Inc., filed herewith.
23.3	Consent of Netherland, Sewell & Associates, Inc., filed herewith.
23.4	Consent of Haas Petroleum Engineering Services, Inc., filed herewith.
23.5	Consent of KPMG LLP as it relates to TGGT Holdings, LLC, 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	2012 Report of Lee Keeling and Associates, Inc., filed herewith.
99.2	2012 Report of Netherland, Sewell & Associates, Inc., filed herewith.
99.3	2011 Report of Haas Petroleum Engineering Services, Inc., filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2011 filed February 27, 2012 and incorporated by reference herein.
99.4	Consolidated Financial Statements of TGGT Holdings, LLC, for the years ended December 31, 2012, 2011 and 2010 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.

DIRECTORS

Douglas H. Miller
Chairman of the Board and
Chief Executive Officer
EXCO Resources, Inc.

Stephen F. Smith
Retired Vice Chairman of the Board,
President and Chief Financial Officer
EXCO Resources, Inc.

Mark F. Mulhern
Executive Vice President and
Chief Financial Officer
EXCO Resources, Inc.

Jeffrey D. Benjamin [1,2,3]
Senior Advisor
Cyrus Capital Partners, LP

Earl E. Ellis
Chairman and Chief Executive Officer
Whole Harvest Products

B. James Ford [2,3]
Managing Director
Oaktree Capital Management, L.P.

Boone Pickens
Chairman and Chief Executive Officer
BP Capital LP

Wilbur L. Ross, Jr.[2,3]
Chairman and Chief Executive Officer
WL Ross & Co. LLC

Jeffrey S. Serota [1,2,3]
Senior Partner
Ares Management, LLC

Robert L. Stillwell [1,2,3]
Retired 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

Harold L. Hickey
President and Chief Operating Officer

Mark F. Mulhern
Executive Vice President and
Chief Financial Officer

William L. Boeing
Vice President, General Counsel
and Secretary

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

Michael R. Chambers, Sr.
Vice President of Operations and General
Manager-East Texas/North Louisiana

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

Ronald G. Edelen
Vice President of Supply Chain

Steven L. Estes
Vice President of Marketing

Joe D. Ford
Vice President of Human Resources

Russell D. Griffin
Vice President of Environmental,
Health and Safety

John D. Jacobi
Vice President of
Business Development

Harold H. Jameson
Vice President and General Manager -
East Texas/North Louisiana JV

Stephen E. Puckett
Vice President of
Reservoir Engineering

J. Douglas Ramsey, Ph.D.
Vice President - Finance, Special Assistant
to the Chairman and Treasurer

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 2013 Annual Meeting of Shareholders will be held on Tuesday, June 11, 2013 at 10:00 am local time, at the Westin Park Central, 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
25,315
(As of April 2, 2013)

EXCO Resources, Inc.
12377 Merit Drive, Suite 1700, Dallas, Texas 75251, www.excoresources.com, Phone: (214) 368-2084, Fax: (214) 368-2087