2013

ANNUAL REPORT

MISSION STATEMENT

EXCO Resources, Inc. is a natural gas and oil company engaged in the exploration, exploitation, acquisition, 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 — SAFETY — TEAMWORK — TECHNOLOGY — GROWTH

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.

Core Areas

↗ HAYNESVILLE AND BOSSIER SHALES – East Texas / North Louisiana

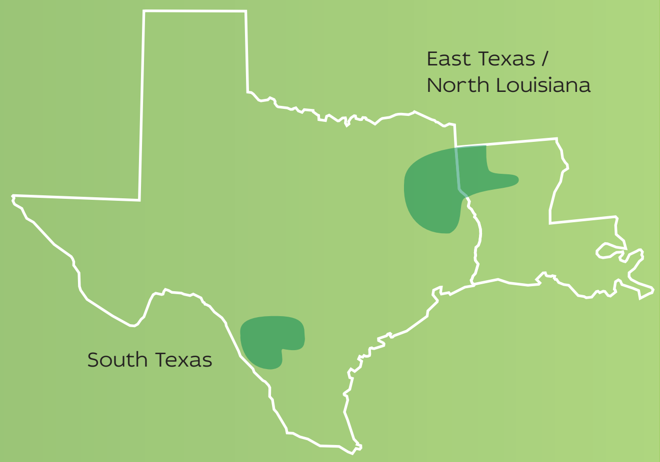
- 70,000 net acres
- Gross well count: 447
- 724 Bcfe of proved reserves

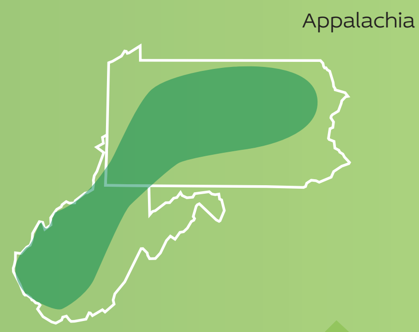
↗ EAGLE FORD SHALE - South Texas

- 47,800 net acres
- Gross well count: 140
- 91 Bcfe of proved reserves

↗ MARCELLUS SHALE – Appalachia

- 145,000 net acres
- Gross well count: 124
- 126 Bcfe of proved reserves

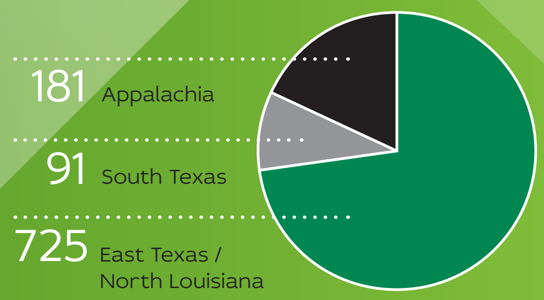




2013 Highlights

- Continued efficient development of asset base
- Closed $943 million of strategic acquisitions
- Reduced leverage through $984 million of asset sales
- Commenced rights offering that raised $273 million

PROVED RESERVES BREAKDOWN (Bcfe)*



* Proved Reserves reflect year-end SEC pricing and excludes EXCO's proportionate share of XCO/HGI Partnership (125 Bcfe) & Other (2 Bcfe).

DEAR FELLOW SHAREHOLDERS

Thank you for your interest in, and support of, EXCO Resources. We appreciate that your decision to invest in EXCO brings with it an expectation that we will be stewards of your capital and deploy it in a way to build long-term value for all of our investors. We are deeply committed to that objective.

EXCO's primary near-term focus is to capitalize on the experience of our technical and operations team to create long-term value. EXCO currently operates more than 7,800 wells and has significant acreage positions in three strategic shale plays in the United States. We believe we have great optionality and upside in our drilling location inventory and will be beneficiaries of a macro improvement in commodity prices. We expect a continuing tightening of supply and demand in natural gas in the United States and rising prices should be a great benefit to an experienced, efficient and low-cost operator like EXCO Resources.

2013 was a year of significant accomplishments at EXCO. Through a combination of efficient development of our asset base, strategic acquisitions and divestitures, and financing transactions, we exited the year with a more diversified asset portfolio that positions EXCO for future growth. EXCO completed approximately $1 billion of asset sales in four separate transactions during the year which helped us close $943 million of strategic acquisitions. In addition, in January 2014, we raised $273 million of equity through a rights offering that enhanced our liquidity and improved our balance sheet, providing us flexibility to exploit our asset position. This letter summarizes these accomplishments and will help frame where EXCO is today and where we are headed in the future.

In February, we formed a partnership focused on conventional assets and 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 in exchange for $575 million in cash, a 25% interest in the limited partnership and a 50% general partnership interest. The primary strategy of the partnership is to efficiently manage its current asset base and acquire conventional producing oil and natural gas properties to enhance asset value and cash flow. In March 2013, the partnership closed its first acquisition by acquiring incremental working interests for $131 million in properties already operated by the partnership. This acquisition was funded with borrowings under the partnership's own credit facility. The partnership's operations are currently funded with its cash flows from operations and, as necessary, its credit facility.

In July, we closed two strategic acquisitions that added to our core area in the Haynesville and established our oil presence in the Eagle Ford for an aggregate purchase price of $943 million. These acquisitions were initially financed with borrowings under our credit agreement. Subsequently, we have paid down the borrowings using proceeds from divestitures and our rights offering.

The $281 million Haynesville acquisition included producing wells and oil, natural gas and mineral leases located in our core Haynesville shale operating area in Caddo and DeSoto Parishes, Louisiana. These properties increased our ownership interest in 170 wells that we operate on approximately 5,500 net acres and also included operated interests in 11 producing wells on approximately 4,000 additional net acres. The acquisition added approximately 55 identified drilling locations to our drilling inventory and added to our contiguous Haynesville shale acreage, where we continue to be one of the premier operators within this play. Our operating team has drilled over 430 wells in the Haynesville shale and has built a competitive advantage through continuous improvement as a leading low-cost operator with a proven manufacturing mode development capability. Our economies of scale in the Haynesville have allowed us to efficiently develop our assets and minimize our costs through greater utilization of multi-well pads and existing infrastructure and facilities.

The $662 million Eagle Ford acquisition included producing wells and oil, natural gas and mineral leases in the Eagle Ford shale in Zavala, Dimmit and Frio counties in South Texas. These properties included operated interests in 120 wells on approximately 53,500 net acres. The acquisition added approximately 300 identified drilling locations to our drilling inventory and also provided farm-in opportunities on additional acreage. We believe this acquisition includes significant upside on the undeveloped acreage while increasing our exposure to oil production. In connection with the acquisition, we entered into a participation agreement and sold a 50% interest in the undeveloped acreage we acquired for $131 million. The participation agreement allows us to diversify the risks associated with the Eagle Ford development while establishing a platform for future growth through the acquisitions of oil-focused proved developed producing properties at attractive prices based on the offer process within the agreement. We are applying our technical and operational expertise developed in the Haynesville to the Eagle Ford shale, and are realizing operational efficiencies as we move to a manufacturing mode in our core Eagle Ford area. Since taking over operations, both our drilling times and overall well costs have been reduced.

In November, we sold our equity interest in our midstream company, TGGT, for net cash proceeds of $240 million and a 4% equity interest in the buyer. We used the proceeds to reduce the borrowings incurred with our 2013 acquisitions. We sold TGGT as the midstream business is not core to our primary strategy of focusing on the exploitation and development of our shale resource plays.

In December, we commenced a common stock rights offering and raised $273 million with the support of our broad shareholder base and our principal investors. The proceeds allowed us to eliminate the asset sale requirement under our credit agreement related to our acquisitions six months ahead of the July 2014 deadline and helped us pay down our revolving indebtedness.

Our position in the Marcellus shale continues to evolve with a combination of appraisal and development wells primarily in Armstrong, Jefferson, Sullivan and Lycoming counties in Pennsylvania. We currently hold 290,000 net acres in the Appalachia basin, with approximately 145,000 of those net acres prospective for the Marcellus shale. As of December 31, 2013, we operated approximately 5,800 vertical shallow wells in Appalachia and 124 horizontal wells in the Marcellus

JEFFREY D. BENJAMIN

Non-Executive
Chairman of the Board

HAROLD L. HICKEY

President and
Chief Operating Officer

shale. During 2013, we turned to sales 20 gross wells. Our drilling program in this region has been limited in response to lower realized gas prices from the widening of differentials. A significant amount of this acreage is held by production allowing us flexibility in the timing of our drilling activities. Our Marcellus acreage position includes over 1,500 drilling locations that provide us long-term optionality and upside to improvements in technology and infrastructure and rising natural gas prices.

On the operations side, our team drilled and turned to sales 99 wells. Of the 99 wells, 51 were in the Haynesville shale, where we have focused on improving the efficiency of our drilling and completion operations which has resulted in significant reductions to our well costs. In DeSoto Parish, our average drilling and completion costs per well decreased to $7.5 million per well during 2013, as compared to $8.0 million per well during 2012 and $9.5 million per well during 2011. We continue to achieve improved drilling times per well and we are currently averaging 33 days from spud to rig release for a typical 16,500-foot Haynesville well in DeSoto Parish.

With the review of 2013, you can see how EXCO significantly enhanced its liquidity as we reduced debt by $581 million from third quarter 2013 levels. We are focused in three strong shale positions (Haynesville and Bossier, Eagle Ford and Marcellus). We have built a solid platform supported by an experienced operating team with a demonstrated ability to continuously drive down costs and improve efficiencies. Our balance sheet and liquidity have been strengthened in 2013 to protect against market fluctuations and allow us to opportunistically pursue growth opportunities.

For 2014, we continue to focus on efficiently developing our asset base and are having solid results replicating our proven Haynesville efficiencies in the Eagle Ford. Managing our balance sheet, maintaining ample liquidity and simplifying our organization remain top priorities. We continue to demonstrate fiscal discipline and our 2014 capital expenditure budget of approximately $370 million is designed to manage our capital expenditures in relation to our operating cash flow. We recently closed the sale of our non-operated West Texas asset for $68 million and used the proceeds to further reduce the borrowings on our revolving indebtedness.

Finally, the Board has engaged an executive recruiting firm to assist in identifying the next CEO of EXCO Resources. We are committed to attracting the right leader to capitalize on our current asset base and operating team and build long-term value for our shareholders.

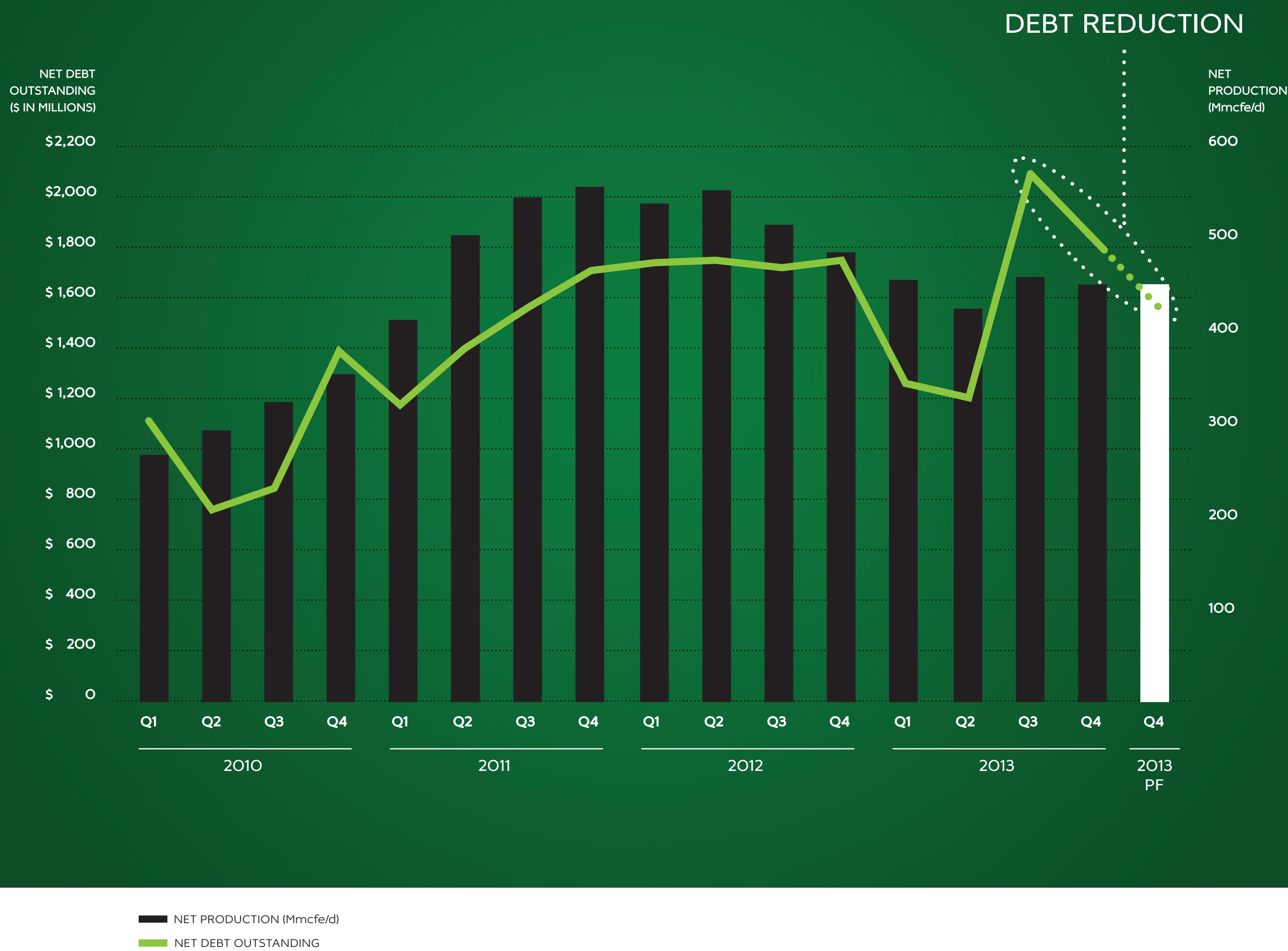
We thank you for your support and look forward to executing our strategy for 2014 and beyond.

Sincerely,

JEFFREY D. BENJAMIN
Non-Executive Chairman of the Board

HAROLD L. HICKEY
President and Chief Operating Officer

N E T   P R O D U C T I O N – N E T   D E B T



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, 2013, 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.

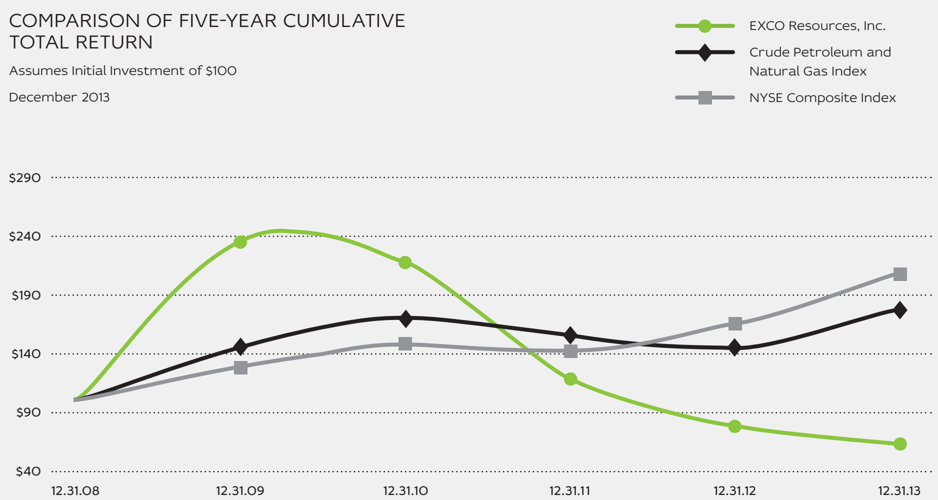
SEC AND NYSE CERTIFICATIONS

The Form 10-K, included herein, which was filed by the company with the SEC for the fiscal year ending December 31, 2013, includes, as exhibits, the certifications of our principal executive officer and principal financial officer required to be filed with the SEC. Our chief executive officer also filed his 2013 annual CEO certification with the NYSE confirming that the company has complied with the NYSE corporate governance listing standards.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

Assumes Initial Investment of $100

December 2013



The graph to the right compares the cumulative total return (what $100 invested on December 31, 2008 would be worth on December 31, 2013) 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					
	12.31.08	12.31.09	12.31.10	12.31.11	12.31.12	12.31.13
EXCO Resources, Inc.	$ 100.00	$ 235.11	$ 216.86	$ 117.99	$ 78.17	$ 63.18
NYSE Composite Index	$ 100.00	$ 128.95	$ 146.69	$ 141.46	$ 164.45	$ 207.85
Crude Petroleum and Natural Gas Index	$ 100.00	$ 144.70	$ 169.75	$ 154.94	$ 144.38	$ 176.87

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, 2013

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 21, 2014, the registrant had 272,782,408 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 $1,042,010,000.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement on Schedule 14A to be furnished to shareholders in connection with its 2014 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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EXCO RESOURCES, INC.
PART I

Item 1. Business

General

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

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

We are an independent oil and natural gas company engaged in the exploitation, exploration, acquisition, 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 Texas, Louisiana and the Appalachia region.

As of December 31, 2013, our Proved Reserves were approximately 1.1 Tcfe, of which 90% were natural gas and 66% were Proved Developed Reserves. As of December 31, 2013, the PV-10 and Standardized Measure of our Proved Reserves was approximately $1.3 billion. For the year ended December 31, 2013, we produced 161.9 Bcfe of oil, natural gas and natural gas liquids.

Our business strategy

Our primary strategy focuses on the exploitation and development of our shale resource plays, while continuing to evaluate complementary acquisitions that meet our strategic and financial objectives. We plan to 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, managing our liquidity and enhancing financial flexibility. We believe this will allow us to create long-term value for our shareholders.

Exploit our shale resource plays

Our primary focus is the development of our core areas as we exploit our extensive inventory of drilling opportunities. We hold significant acreage positions in three prominent shale plays in the United States:

- East Texas and North Louisiana - we currently hold approximately 70,000 net acres in the Haynesville/Bossier shales;
- South Texas - we currently hold approximately 47,800 net acres in the Eagle Ford shale; and
- Appalachia - we currently hold approximately 145,000 net acres prospective in the Marcellus shale.

We commenced our horizontal drilling program in the Haynesville/Bossier shales during 2008 and have gained extensive amounts of technical and operational expertise within these formations. We have spud 430 operated horizontal wells from the commencement of our drilling program through December 31, 2013. We also own working interests in 178 Haynesville/Bossier shale horizontal wells operated by others. We have accumulated significant amounts of contiguous acreage and are one of the largest operators within this region. Our economies of scale have allowed us to efficiently develop our assets and minimize our costs through greater utilization of multi-well pads and existing infrastructure and facilities. During 2013, we acquired additional assets in our core area of the Haynesville shale including additional working interests in our operated wells and operated interests in producing wells in sections with additional developmental opportunities.

During 2013, we acquired producing wells and non-producing leasehold interests in the Eagle Ford shale. We believe this acquisition includes significant upside on the undeveloped acreage while increasing our exposure to oil production. In addition, we entered into a farm-out agreement covering additional acreage adjacent to the acquired properties. In connection with the closing of the acquisition of the Eagle Ford assets, we entered into a participation agreement with Kohlberg Kravis Roberts & Co. L.P. ("KKR") to jointly develop the assets ("KKR Participation Agreement"). We believe this agreement will allow us to diversify the risks associated with this development while establishing a platform for growth through the acquisition of oil focused proved developed producing properties at attractive prices based on the offer process within the agreement. We intend to apply our technical and operational expertise from other shale plays to the Eagle Ford shale and realize operational efficiencies as we move to a manufacturing mode in our core area. Since we closed on the acquisition of the Eagle Ford assets, we have spud 26 operated horizontal wells in the Eagle Ford shale through December 31, 2013.

Our principal activities in the Marcellus shale are focused on technical evaluations of our acreage holdings and a disciplined appraisal drilling program. In 2014, we are planning appraisal initiatives as we evaluate future development activities. A substantial portion of our shale resource play acreage is held-by-production, which gives us flexibility to defer drilling as we evaluate our development activities without the threat of losing valuable leases.

Evaluate complementary acquisitions that meet our strategic and financial objectives

We continue to evaluate acreage opportunities and acquisitions of producing properties in our shale areas. We believe we can leverage our technical expertise and economies of scale to maximize our returns in these areas. Our acquisition history over the last five years has been focused on shale resource plays with an emphasis on the acquisition of undeveloped acreage. Undeveloped acreage acquisitions differ from acquisitions of producing properties as undeveloped acreage acquisitions do not result in immediate production and cash flows or provide incremental borrowing base capacity under our credit agreement (the "EXCO Resources Credit Agreement"). The acquisitions we closed in July 2013 consisted of producing properties and undeveloped acreage. Our current business development focus is on evaluating acreage and producing property acquisition opportunities that are complementary to our current asset base.

Manage our liquidity and enhance financial flexibility

We actively manage our liquidity to ensure that we are able to execute our business strategies. We continuously review our portfolio and evaluate transactions that would enhance our liquidity and allow us to redeploy capital to other projects with higher rates of return. During 2013, we executed several key transactions that improved our liquidity and financial flexibility. We utilized the proceeds from these transactions to reduce indebtedness under the EXCO Resources Credit Agreement and facilitate the acquisitions of the Haynesville and Eagle Ford assets. These transactions included the following:

- sold our equity interest in TGGT Holdings, LLC (“TGGT”) to Azure Midstream Holdings LLC (“Azure”) for cash proceeds of approximately $240.2 million and an equity interest of approximately 4% in Azure;
- formed a partnership (“EXCO/HGI Partnership”) with Harbinger Group Inc. (“HGI”). We contributed our conventional non-shale assets in East Texas and North Louisiana and our shallow Canyon Sand and certain other assets in the Permian Basin of West Texas to the EXCO/HGI Partnership in exchange for net proceeds of approximately $574.8 million and a 25.5% economic interest in the EXCO/HGI Partnership. The operations of the EXCO/HGI Partnership are currently funded with its cash flows from operations and its credit facility ("EXCO/HGI Partnership Credit Agreement");
- sold an undivided 50% interest in the undeveloped Eagle Ford acreage we acquired to KKR for approximately $130.9 million and entered into the KKR Participation Agreement to jointly develop these assets; and
- sold an undivided 50% interest in certain undeveloped acreage with horizontal shale drilling opportunities in the Permian Basin. We received $37.9 million in cash and the purchaser agreed to fund our share of drilling and completion costs within the joint venture area up to $18.9 million. The private party was designated as the operator under the joint development agreement. On February 13, 2014, we entered into a purchase and sale agreement with the private party for the sale of our interest in the joint venture for approximately $65.0 million.

We closed a rights offering of our common stock and related private placement on January 17, 2014 which resulted in the issuance of 54,574,734 shares of our common stock for proceeds of $272.9 million. We utilized the proceeds from the rights offering to repay indebtedness under the EXCO Resources Credit Agreement. After giving effect to the repayment of indebtedness with proceeds from the rights offering, the revolving commitment under the EXCO Resources Credit Agreement had a $900.0 million borrowing base with unused borrowing capacity of $401.4 million.

Our board of directors approved a capital expenditure budget of $368.0 million for 2014. We expect the capital expenditure program will be funded primarily by our operating cash flow. Our capital program was designed to minimize the impact of production declines while managing our capital expenditures in relation to our operating cash flow. We believe our 2014 budget will increase our exposure to crude oil production as it includes $138.0 million of capital expenditures that are focused on drilling and development activities for oil in our South Texas region. Our capital expenditure budget excludes the EXCO/HGI Partnership, which funds its capital expenditures through internally generated cash flow and its credit agreement.

We are also evaluating potential transactions which would further enhance our liquidity, including additional divestitures of non-core assets, and continuous evaluation of cost reduction initiatives in operating and general and administrative costs.

We use derivative financial instruments to 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 comprehensive derivative financial instrument program will mitigate the impact of volatility in commodity prices and allow us to achieve more predictable cash flows.

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 a geographically diversified reserve base including significant acreage positions in some of the most prominent shale plays in the United States. Our principal operations are in Texas, Louisiana and the Appalachia region. In addition, a significant portion of our acreage is held-by-production which allows us to develop these properties within our optimum time frame. Our properties are generally characterized by:

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

Operational control

We operate a significant portion of our properties which allows us to manage our operating costs and better control capital expenditures as well as the timing of development and exploitation activities. Therefore, we are able to allocate our capital to the most attractive projects based on commodity prices, rates of return and industry trends. As of December 31, 2013, we operated 7,863 of our 8,453 gross wells, or wells representing approximately 97% of our Proved Developed Reserves. We have continued to demonstrate improved drilling and completion results in our operated areas while maintaining low capital and operating costs.

Skilled technical personnel and experienced management team

We have developed a workforce that has a significant number of highly skilled technical and operational personnel who have been successful in developing our shale resources. We will leverage our technical expertise to exploit our asset base in an efficient and cost-effective manner. We believe our technical expertise gives us a competitive advantage in our key operating areas.

Our management team has led both public and private oil and natural gas companies and has extensive industry experience in acquiring, exploring, exploiting and developing oil and natural gas properties. We believe that our management team will be instrumental in executing a disciplined approach to accomplish our business strategies. Our board of directors is currently conducting a search for a new chief executive officer who will bring additional leadership, experience and expertise to our current management team.

Plans for 2014

Our plans for 2014 primarily focus on the exploitation and development of our core assets. These plans include a disciplined development program which will primarily be funded with cash flows from our operations. We expect our development program will result in a decline in natural gas production while increasing our crude oil production. We will also focus on improving our operating margins as a result of initiatives to manage our operating and general and administrative costs. This will allow us to preserve our liquidity and capital resources in preparation for future growth, including purchases of Eagle Ford assets under the KKR Participation Agreement beginning in 2015. Although our focus is on the exploitation and development of our current asset base, we will also continue to evaluate complementary acquisitions if opportunities arise that meet our strategic and financial objectives.

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, 2013:

Areas	Total Proved Reserves (Bcfe) (1)	PV-10 (in millions) (1) (2)	Average daily net production (Mmcfe) (3)
East Texas/North Louisiana	725.1	$ 526.1	318
South Texas (4)	90.6	455.1	44
Appalachia	181.1	157.9	65
Permian and other	2.3	9.2	2
EXCO/HGI Partnership (5)	125.2	104.0	25
Total	1,124.3	$ 1,252.3	454

Areas	Estimated drilling locations (6)	Total gross acreage	Total net acreage
East Texas/North Louisiana	2,167	189,300	87,000
South Texas (4)	325	97,000	47,800
Appalachia	3,533	672,500	290,400
Permian and other	101	29,500	18,200
Total	6,126	988,300	443,400
EXCO/HGI Partnership (7)	805	179,200	39,400

(1) The total Proved Reserves and PV-10 as of December 31, 2013 were prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC"). The estimated future plugging and abandonment costs necessary to compute PV-10 were computed internally.

(2) The PV-10 data used in this table was 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, 2013 and ending on December 1, 2013, of $3.67 per Mmbtu for natural gas and $96.78 per Bbl for oil, in each case adjusted for geographical and historical differentials. The price per barrel for NGLs was $39.92 per barrel and was computed on the trailing 12 month average of realized prices. 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 ("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, 2013 was $1.3 billion. The Standardized Measure represents the PV-10 after giving effect to income taxes, and is calculated in accordance with the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 932, *Extractive Activities, Oil and Gas* ("ASC 932"). Our existing net operating loss carryforwards eliminated estimated future income taxes for the year ended December 31, 2013. 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) The average daily net production rate was calculated based on the average daily rate during the final week of the year ended December 31, 2013.

(4) We plan on developing certain undeveloped acreage in the Eagle Ford shale as part of the KKR Participation Agreement. Under this agreement, we will assign half of our working interest in a well to KKR upon commencement of development. Therefore, we have only included half of our current working interest in the undeveloped locations subject to this agreement within our Proved Reserves. We have not incorporated the impact of future buybacks under the KKR Participation Agreement within our Proved Reserves. The acreage in this region consists of 36,500 net acres outside of our core area in Zavala County that are subject to KKR's right to participate in each proposed well. Our acreage in the South Texas region does not include the undeveloped locations associated with the farmout agreement with Chesapeake Energy Corporation ("Chesapeake").

(5) We own a 25.5% economic interest in the EXCO/HGI Partnership and proportionately consolidate the reserves. The reserves of the EXCO/HGI Partnership include conventional shallow producing assets in East Texas and North Louisiana and shallow Canyon Sand and other assets in the Permian Basin of West Texas.

(6) Identified drilling locations represent total gross drilling locations identified and scheduled by our management as an estimate of our multi-year drilling activities on existing acreage. Of the total drilling locations shown in the table, approximately 510 are classified as proved excluding the proved locations of the EXCO/HGI Partnership. 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").

(7) The total identified drilling locations for the EXCO/HGI Partnership shown in the table include approximately 58 locations classified as proved. The net acreage reported for the EXCO/HGI Partnership represents our 25.5% economic interest. The acreage reported for the EXCO/HGI Partnership primarily consists of shallow rights in the same acreage for which EXCO owns the deep rights.

Our development and exploitation project areas

East Texas /North Louisiana

The East Texas/ North Louisiana area is our largest producing region with operations focused on the Haynesville and Bossier shales. 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. Our acreage in this region is predominantly held-by-production. The Haynesville shale is located 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 wells with 16,000 to 20,000 feet of total measured depth.

Our development drilling program in the Haynesville shale play is concentrated in the Holly area in DeSoto Parish, Louisiana and the Shelby area in East Texas. At December 31, 2013, we operated three drilling rigs focused on our Holly area. During 2014, we plan to operate an average of four drilling rigs to drill approximately 42 gross (20.5 net) wells and complete approximately 35 gross (18.3 net) wells. As of December 31, 2013, our average operated shale natural gas production was approximately 775 gross (304.5 net) Mmcfe per day. Including non-operated volumes, our total net production from the Haynesville and Bossier shales was 318.0 Mmcfe per day as of December 31, 2013.

Holly area

Our position in the Holly area consists of 29,700 net acres in DeSoto Parish, of which 99% net acres are held-by-production. We continue to develop the Holly area in DeSoto Parish in a manufacturing mode utilizing multi-well pad development. The multi-well pad design minimizes surface impact and provides for a more capital efficient gathering and production system design compared to single well locations. At December 31, 2013, we had three drilling rigs running in the area and a total of 369 gross operated horizontal wells flowing to sales. We recently modified our development plan from eight wells per section to six wells per section in order to optimize our rate of return and value for each section. 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. As of December 31, 2013, we had 42 developed units and 37 undeveloped units. Our plans for 2014 are to develop seven of these units which includes drilling 34 gross (17.3 net) wells.

Shelby area

Our position in the Shelby area consists of 16,600 net acres in San Augustine, Nacogdoches and Shelby Counties, of which 95% net acres are held-by-production. As of December 31, 2013, we had a total of 70 gross operated horizontal wells flowing to sales. Our activity in this area has historically consisted of delineating the acreage, establishing infrastructure, performing technical evaluations, testing different completion designs and evaluating different flowback methodologies. We suspended our drilling program in this region during 2012 and 2013 in order to focus our resources on the Holly area of the Haynesville shale. Based on our internal engineering and geological analysis and the recent success of other operators on offset acreage using enhanced completion methods, we resumed our drilling program in this area during 2014. Additionally, our ability to reduce drilling and completion costs in the Haynesville shale has significantly improved the economics of drilling in this area. Our plans for 2014 include drilling 8 gross (3.8 net) wells which will include laterals as long as 7,000 feet, more proppant per completed lateral foot and more restricted flowback. If the enhanced completion methods are successful on our acreage, this program will provide attractive economics in the current price environment and provide a growth platform for future development.

Haynesville shale operating effectiveness

We have focused on improving the efficiency of our drilling and completion operations which has resulted in significant reductions to our well costs. In DeSoto Parish, our average drilling and completion costs per well decreased to $7.5 million per well during 2013, as compared to $8.0 million per well during 2012 and $9.5 million per well during 2011. We continue to achieve improved drilling times per well and we are currently averaging 33 days from spud to rig release for a typical 16,500 foot Haynesville well in DeSoto Parish. In addition to our success in reducing well costs attributable to drilling, we are also focused on cost effective and optimized completions. Approximately 40% of our well cost is incurred during the completion phase. We utilize one to two fracture stimulation fleets and continue to see improved consistency and efficiencies in our fracturing operations. We design our development program to flow natural gas directly to sales once the unit is completed. This is possible due to close coordination with our midstream service provider, which installs gathering lines in concert with our drilling operations in most of our development areas.

Our production operations team is focused on lowering our direct operating costs including water management, efficient utilization of our personnel, equipment rentals and chemicals. The water management initiatives include establishing fixed prices per barrel for disposal and connecting additional wells to a piped water disposal system which reduces the amount of higher cost water disposal by truck. Though the use of automation at the well sites, we can better utilize company personnel time to perform maintenance work and reduce the use of third party services. We also have an operations tracking database system in place that enables us to be proactive in maintenance and repairs which results in cost efficiencies. The gas cooler fleet used in our Haynesville program has been significantly reduced in size and in most cases we are using a single cooler for gas streams from multiple wells for shorter periods of time. We plan to continue to efficiently manage our chemical programs which will allow us reduce costs by minimizing well intervention work.

We are also focused on several initiatives to enhance and manage our base production. We are installing artificial lift devices on a number of wells, administering an active foamer injection program and performing coiled tubing and slickline cleanouts as necessary to enhance base production. We have also lowered the production tubing to a deeper landing point in the wells to more efficiently unload fluids in the lateral. We are currently conducting a pipeline pressure study to evaluate well performance in response to a lower pressured system. We are planning to transition a portion of our Holly field to a lower system pressure by isolating a portion of the gathering system that will result in a reduction in line pressure. We are working closely with our midstream service provider to plan and design the testing program and expect to implement the project in 2014. We are also planning to perform our first refrac stimulation test in 2014. The test is designed to perform a second fracture stimulation treatment in an existing well to re-stimulate the shale reservoir near the wellbore. This will enhance the connection from the reservoir to the wellbore to increase productivity and more effectively produce the resources.

We have a Dallas based operations control center that is manned 24 hours a day that monitors our Haynesville, Bossier, Eagle Ford and Marcellus shale wells. This control system gives us the ability to monitor and control natural gas flow over a large portion of our fields, which allows us to optimize the daily natural gas flow from our assets and minimize downtime.

South Texas

We acquired assets in the South Texas region in July 2013 focused on the Eagle Ford shale including 120 producing wells and undeveloped acreage. Our position in this region includes 47,800 net acres with an option to earn additional net acres under the terms of a farmout agreement with Chesapeake covering portions of Zavala, Dimmit and Frio Counties, Texas. Our acreage in the Eagle Ford shale is in the oil window and averages 375 feet in gross thickness at true vertical depths ranging from 5,400 to 6,800 feet. Our lateral lengths average 7,100 feet and range from 5,000 to 9,000 feet. The total measured depth of our wells averages 14,600 feet. Our acreage in the area is primarily held-by-production and also includes additional upside in formations such as the Austin Chalk, Buda and Pearsall formations. We have acquired 3-D seismic data over a large portion of our acreage to help assess the subsurface potential of the assets.

We drilled 23 gross (3.8 net) wells in the core area of Zavala County between the acquisition date and December 31, 2013. Our drilling was focused on moving to a manufacturing mode using multi-well pads followed by fracture stimulating the group of wells simultaneously. These well development groups range from 4 to 12 wells and allow us to maximize reserves recovery while reducing costs. Of the wells we drilled in our core area between the acquisition date and December 31, 2013, we turned-to-sales 7 gross (1.2 net) wells with an average initial production rate of 570 barrels of oil per day. As of December 31, 2013, our average operated shale oil production was approximately 15,200 gross (6,700 net) barrels of oil per day from 130 wells.

Our 2014 development plan in the Eagle Ford shale is to drill 90 gross (15.2 net) wells with a five rig program. This includes 84 gross (14.2 net) horizontal wells in our core area of Zavala County in connection with the KKR Participation Agreement. We will continue to evaluate the farm-out acreage and plan to drill 6 gross (1.0 net) wells during 2014. We will utilize one to two fracture stimulation fleets to turn to sales approximately 82 gross (14.3 net) wells during the year. We expect to drill over 300 wells over approximately four years with our current development plan on 500 foot spacing between laterals.

Eagle Ford shale operational effectiveness

We have utilized our expertise from other shale developments and have realized significant operational efficiencies in our recently acquired Eagle Ford assets. We are currently averaging 15 days from spud to rig release and the current average drilling and completion costs per well are approximately $6.9 million. Additionally, we recently secured a completion contract that will reduce our fracture stimulation costs compared to the date of the acquisition. New wells typically flow for one year or more before requiring artificial lift. We installed 21 additional pumping units in late 2013 and we expect to install 90 pumping units in 2014.

We renegotiated our salt water disposal contract which will reduce our disposal costs as compared to such costs in place on the date of the acquisition. We re-piped and automated flare lines to mitigate downtime due to periodic high line pressures, and are developing a long term solution to increase capacity of the gathering system for our core area and to align with our development plan.

Our future plans include the construction and operation of multiple central facilities to reduce transportation costs and operating expenses. We also plan to construct additional water containment and other facilities to recycle water to source the completions in the core area. We are currently in the process of designing an electrical distribution network over the core development area that will provide a more efficient cost structure to operate the field.

Appalachia

Our operations in the Appalachia region have primarily included testing and selectively developing the Marcellus shale with horizontal drilling while maintaining our existing conventional production from shallow vertical wells. We currently hold approximately 290,000 net acres in the Appalachian basin, with approximately 145,000 of these net acres prospective for the Marcellus shale. A significant amount of this acreage is held-by-production. Of the Marcellus shale acreage that is not held-by-production, 2,800 net acres are scheduled to expire in 2014. As of December 31, 2013 we operated a total of 5,801 vertical shallow wells flowing to sales with an average gross production rate of approximately 32 (13.1 net) Mmcfe per day. As of December 31, 2013 we operated a total of 124 horizontal wells in the Marcellus shale with an average gross production rate of approximately 179 (49.7 net) Mmcfe per day. Including non-operated volumes, our net production in the Appalachia region was 64.5 Mmcfe per day as of December 31, 2013.

Our Pennsylvania acreage encompasses 23 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 9,000 feet. 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.

Marcellus shale

Our 2013 development program was a combination of appraisal and development wells in Northeast Pennsylvania, which primarily included Sullivan and Lycoming Counties and our Central Pennsylvania area, which includes mainly Armstrong and Jefferson Counties. Our drilling was focused on holding large, contiguous blocks of prospective acreage while turning to sales our inventory of wells that were waiting on completion. During 2013, we spud 4 gross (1.7 net) wells and turned to sales 20 gross (8.0 net) wells. We have reduced our drilling program in this region in response to lower realized natural gas prices from the widening of regional price differentials in order to focus on projects with higher rates of return. Our 2014 drilling plan includes 2 gross (0.5 net) operated appraisal wells in the Northeast Pennsylvania area. We have been encouraged by the recent results of our wells turned-to-sales in this region and are currently evaluating our drilling plans beyond 2014. A significant amount of our acreage is held-by-production, which allows us to control the timing of the development of this region.

Marcellus shale operational effectiveness

During 2013, we reduced our average costs per well drilled in the Marcellus shale due to engineering design improvements, operational efficiencies, more developed infrastructure and focused supply chain processes. These wells included lateral lengths ranging from 3,000 to 6,000 feet. These reductions in costs will allow us to improve the economics of drilling in this region; however our current strategy for these areas includes appraising and holding large contiguous blocks of primary term acreage while consolidating our lease positions within these core areas.

Permian Basin

During 2012, we acquired approximately 15,000 prospective net acres with horizontal drilling potential in the Permian Basin located in Irion County, Texas. During 2013, we sold 50% of this acreage for $37.9 million and the purchaser agreed to fund our share of drilling and completion costs up to $18.9 million. We formed a joint venture with the purchaser to develop the acreage in which they are designated as the operator. We also leased an additional 2,000 net acres within the joint venture area during 2013 adjacent to the original acreage. The joint venture spud 5 gross (2.5 net) horizontal wells during 2013 targeting the Wolfcamp formation, and completed and turned-to-sales 2 gross (1.0 net) of these wells. As of December 31, 2013, there was approximately $5.1 million remaining under the carry and this is expected to be exhausted upon completion of the fifth well.

On February 13, 2014, we entered into a purchase and sale agreement with our joint venture partner for the sale of our interest, including producing wells and undeveloped acreage, for approximately $65.0 million, subject to customary purchase price adjustments and the receipt of certain third-party consents. The effective date of the transaction will be January 1, 2014 and any amounts remaining under the drilling carry will be terminated upon closing of the acquisition. The transaction is expected to close in the first half of 2014.

EXCO/HGI Partnership

We formed the EXCO/HGI Partnership during 2013 in which we own a 25.5% economic interest. The primary strategy of the EXCO/HGI Partnership is to exploit its current asset base and acquire conventional producing oil and natural gas properties to enhance asset value and cash flow. The EXCO/HGI Partnership's primary assets include shallow conventional properties in the East Texas/North Louisiana region and the Permian Basin. The net amounts for the drilling and production results presented below represent our 25.5% economic interest in the EXCO/HGI Partnership.

Permian

The EXCO/HGI Partnership's properties in the Permian Basin are located primarily in the Sugg Ranch field in Irion County, Texas. The production from these properties is primarily from the Canyon Sand formation from depths of 6,700 to 7,900 feet. During the period from inception to December 31, 2013, the partnership drilled and completed 19 gross (4.6 net) wells in the Sugg Ranch area. Economics for this drilling activity typically have high rates-of-return driven by oil and NGL content. The partnership expects to run one operated rig intermittently at Sugg Ranch during 2014 targeting the Canyon Sand formation. At December 31, 2013, production from the 444 operated partnership wells averaged approximately 5.0 gross (1.0 net) Mboe per day. This average production rate consisted of 0.3 net Mbbls of oil, 0.3 net Mmcf of natural gas, and 0.4 net Mbbls of natural gas liquids per day.

East Texas/North Louisiana

The Vernon Field in Jackson Parish, Louisiana is the most significant producing field in the EXCO/HGI Partnership and 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 including Holly, Kingston, Caspiana, and Longwood, as well as acreage and production in Harrison, Panola, and Gregg Counties in Texas, primarily across three fields including Carthage, Waskom and Danville. These producing zones range in depth from 7,800 feet to 11,000 feet. At December 31, 2013, net operated production averaged approximately 9.9 Mmcfe per day from Vernon Field and approximately 9.0 Mmcfe per day from other fields in East Texas/North Louisiana. The primary focus in the East Texas/North Louisiana fields is to minimize operating expenses while maintaining production. The EXCO/HGI Partnership's capital projects in this region during 2014 will be focused on recompletions in order to maximize recovery from these assets. In East Texas/North Louisiana, the EXCO/HGI Partnership currently has 905 operated wells flowing to sales with a total operated production rate of approximately 107 gross (18.9 net) Mmcfe per day.

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 Texas, Louisiana and Appalachia region.

As of December 31, 2013, we had approximately 70,000 net acres in our East Texas/North Louisiana region for the Haynesville and Bossier shale formations, 47,800 net acres in our South Texas region for the Eagle Ford shale formation, 145,000 net acres in our Appalachia region prospective for the Marcellus shale formation, all of which are subject to hydraulic fracturing operations. As of December 31, 2013, a total of 725.1 Bcfe of our Proved Reserves were located in our East Texas/North Louisiana operating area, of which 724.2 Bcfe of Proved Reserves were associated with our Haynesville and Bossier shale properties. As of December 31, 2013, a total of 90.6 Bcfe of our Proved Reserves were located in our South Texas operating area, of which predominantly all of the Proved Reserves were associated with Eagle Ford shale assets. As of December 31, 2013, a total of 181.1 Bcfe of our Proved Reserves were located in our Appalachia region, of which 126.2 Bcfe of Proved Reserves were associated with our Marcellus shale properties.

Although the cost of each well will vary, the costs associated with hydraulic fracturing activities on average represent the following portions of the total costs of drilling and completing a well: Haynesville and Bossier shale formation - approximately 15-25%; Eagle Ford shale formation - approximately 35-45%; and Marcellus shale formation - approximately 25-35%.

We review best practices and industry standards to comply with 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. 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, 2013 were approximately 1.1 Tcfe, of which approximately 84% were related to our shale properties. Of our Proved Reserves attributed to shale properties, approximately 77% were located in the Haynesville/Bossier shale, 13% in the Marcellus shale and 10% in the Eagle Ford shale. Our non-shale Proved Reserves represented approximately 16% of total Proved Reserves as of December 31, 2013, which consisted primarily of conventional assets in the Appalachia region and our proportionate share of the conventional assets held by the EXCO/HGI Partnership in the East Texas/North Louisiana and Permian regions.

The following table summarizes Proved Reserves as of December 31, 2013, 2012, and 2011. This information was prepared in accordance with the rules and regulations of the SEC.

	As of December 31,		
	2013	**2012**	**2011**
Oil (Mbbls)			
Developed	11,274	4,371	4,565
Undeveloped	4,104	1,199	1,789
Total	15,378	5,570	6,354
Natural gas (Mmcf)			
Developed	657,116	917,326	955,522
Undeveloped	359,363	18,806	335,942
Total	1,016,479	936,132	1,291,464
Natural gas liquids (Mbbls) (1)			
Developed	2,088	4,784	—
Undeveloped	495	1,855	—
Total	2,583	6,639	—
Equivalent reserves (Mmcfe)			
Developed	737,291	972,256	982,912
Undeveloped	386,954	37,130	346,676
Total	1,124,245	1,009,386	1,329,588
PV-10 (in millions) (2)			
Developed	$ 1,153.5	$ 666.0	$ 1,545.7
Undeveloped	98.8	30.1	128.0
Total	$ 1,252.3	$ 696.1	$ 1,673.7
Standardized Measure (in millions) (3)	$ 1,252.3	$ 696.1	$ 1,426.5

(1) Beginning in 2012, we began reporting our NGLs separately. In 2011, 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 trailing 12 month average of realized prices.

	Average spot prices		
	Oil (per Bbl)	Natural gas (per Mmbtu)	Natural gas liquid (per Bbl)
December 31, 2013	$ 96.78	$ 3.67	$ 39.92
December 31, 2012	94.71	2.76	46.57
December 31, 2011	96.19	4.12	—

(3) There is no difference in Standardized Measure and PV-10 for the years ended December 31, 2013 and 2012 as the impacts of 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, 2013, 2012 and 2011:

	As of December 31,		
(in millions)	2013	2012	2011
PV-10	$ 1,252.3	$ 696.1	$ 1,673.7
Future income taxes	—	—	(390.8)
Discount of future income taxes at 10% per annum	—	—	143.6
Standardized Measure	$ 1,252.3	$ 696.1	$ 1,426.5

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. We also retain outside independent engineering firms to prepare or audit 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 Associates, Inc. ("Lee Keeling"), Netherland, Sewell & Associates, Inc. ("NSAI"), and Ryder Scott Company, L.P. ("Ryder Scott") in connection with the preparation of their estimates of our Proved Reserves or audit of the Proved Reserves prepared by EXCO's internal engineers. Our Vice President of Engineering is a registered Professional Engineer with over 35 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 or auditing of our oil and natural gas reserves.

The estimates of Proved Reserves and future net cash flows for our non-shale properties, excluding the EXCO/HGI Partnership after its formation, as of December 31, 2013, 2012 and 2011 have been prepared by Lee Keeling. The estimates of

Proved Reserves for the EXCO/HGI Partnership were prepared by Lee Keeling as of September 30, 2013 and updated by our internal engineers as of December 31, 2013. Our estimated Proved Reserves and future net cash flows for our shale properties in the South Texas region were prepared by Ryder Scott as of December 31, 2013. Our estimated Proved Reserves and future net cash flows for our shale properties in all regions except South Texas were prepared by our internal engineers and audited by NSAI as of December 31, 2013. 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 were prepared by Haas Petroleum Engineering Services, Inc. Lee Keeling, Haas Petroleum Engineering Services, Inc., NSAI and Ryder Scott 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, NSAI and Ryder Scott 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 20. 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, NSAI and Ryder Scott 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 or performing an audit of our Proved Reserves and future net cash flows attributable to our interests, Lee Keeling, NSAI and Ryder Scott 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, NSAI or Ryder Scott which brought into question the validity or sufficiency of any such information or data, Lee Keeling, NSAI or Ryder Scott 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, NSAI and Ryder Scott determined that their estimates of Proved Reserves or our audited 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, 2013 and changes in our Proved Reserves during 2013. This discussion and analysis should be read in conjunction with “Note 20. 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, 2013 to December 31, 2013.

	Oil (Mbbls)	Natural gas (Mmcf)	Natural gas liquids (Mbbls)	Equivalent natural gas (Mmcfe)
Proved Developed Reserves	11,274	657,116	2,088	737,291
Proved Undeveloped Reserves	4,104	359,363	495	386,954
Total Proved Reserves	15,378	1,016,479	2,583	1,124,245
The changes in reserves for the year are as follows:				
January 1, 2013	5,570	936,132	6,639	1,009,386
Purchases of reserves in place	16,022	290,933	2,201	400,271
Discoveries and extensions	5,960	46,834	513	85,672
Revisions of previous estimates (1):				
Reclassification to unproved reserves (2)	(190)	(1,509)	(196)	(3,825)
Changes in price	457	272,614	686	279,472
Other factors	(3,029)	(105,186)	(545)	(126,630)
Sales of reserves in place	(8,224)	(270,018)	(6,472)	(358,194)
Production	(1,188)	(153,321)	(243)	(161,907)
December 31, 2013	15,378	1,016,479	2,583	1,124,245

(1) Revisions of previous estimates include both reserves in place at the beginning of the year and acquisitions during the year.

(2) Represents Proved Undeveloped Reserves reclassified to unproved reserves pursuant to the five year development rule established by the SEC. This reclassification was a result of decisions not to commit development capital to certain conventional properties held by the EXCO/HGI Partnership in the Permian Basin. 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.

Purchases of reserves in place

Purchases of reserves in place consisted primarily of our acquisition of Haynesville and Eagle Ford assets from Chesapeake in July 2013. The acquisition in the Haynesville shale primarily added natural gas reserves from both an incremental working interests in proved developed producing properties and new leases containing proved producing properties and proved undeveloped locations in our core area of DeSoto Parish, Louisiana. The acquired Haynesville assets added 260.0 Bcfe of Proved Reserves which consisted solely of natural gas reserves. The acquisition in the Eagle Ford shale primarily added oil reserves from proved developed producing properties and undeveloped locations that we plan on developing under a participation agreement with a joint venture partner. The acquired Eagle Ford assets added 115.7 Bcfe of Proved Reserves which consisted of 83% oil, 8% natural gas and 9% natural gas liquid reserves. In addition, purchases of reserves in place included 24.6 Bcfe of Proved Reserves for our proportionate share of the EXCO/HGI Partnership's acquisition of shallow Cotton Valley assets. The reserve quantities attributable to purchases of reserves in place were calculated based on our estimates and assumptions as of the respective acquisition dates.

Discoveries and extensions

Proved Reserves additions from discoveries and extensions in 2013 were 85.7 Bcfe. The additions in the Eagle Ford shale were 36.5 Bcfe as a result of our development subsequent to the acquisition of these properties. The Marcellus shale accounted for 33.6 Bcfe of the total additions as a result of our completion activities and limited appraisal drilling program. The remaining additions included 10.2 Bcfe in the Haynesville shale, 3.9 Bcfe for conventional properties held by the EXCO/HGI Partnership in the Permian Basin, and 1.5 Bcfe for shale properties in the Permian Basin.

Revisions of previous estimates

Our revisions of previous estimates included upward revisions to our Proved Reserve quantities of 279.5 Bcfe as a result of an increase in price, which extended the economic life of certain producing properties and resulted in the reclassification of unproved locations to Proved Undeveloped properties that became economical when using the average of prices for a trailing 12 month period. This change in price was primarily driven by the increase in the trailing 12 month average of natural gas prices from $2.76 per Mmbtu for the year-ended December 31, 2012 to $3.67 per Mmbtu for the year ended December 31, 2013.

The upward revisions due to changes in price were partially offset by downward revisions of 126.6 Bcfe in Proved Reserve quantities due to performance and other factors. These revisions include 91.6 Bcfe from the Haynesville shale assets due to a combination of operational issues including scaling, liquid loading due to high-line pressure and the impact of drainage on new wells drilled directly offset to the unit wells. The majority of our Proved Developed Producing wells produce into a high line pressure system and are showing signs of liquid loading. We have plans to reduce line pressure in the field and expand our artificial lift program. In addition, most of these wells are drilled on 80 acre spacing with the closest offsets to the original unit wells showing lower reserves compared to previous estimates. We have modified our spacing program from eight wells per section to six wells per section in order to optimize our rate of return and value for each section. However, these planned improvements will not be incorporated into our Proved Reserves until we have the data to support and objectively quantify these amounts.

Sales of reserves in place

Sales of reserves in place consisted of our contribution of conventional properties to the EXCO/HGI Partnership and the sale of undeveloped acreage in the Eagle Ford shale to KKR. The properties contributed to the EXCO/HGI Partnership included Proved Reserves of 327.6 Bcfe (net of our 25.5% proportionate interest) for shallow producing assets in East Texas and North Louisiana and shallow Canyon Sand and other assets in the Permian Basin of West Texas. The properties sold to KKR included 30.6 Bcfe of proved undeveloped reserves in the Eagle Ford shale. We retained an interest in these properties and they will be jointly developed under the KKR Participation Agreement. The reserve quantities attributable to sales of reserves in place were calculated based on our estimates and assumptions as of the respective divestiture dates.

Oil and natural gas production

Total oil and natural gas production in 2013 was 161.9 Bcfe, which included approximately 5.0 Bcfe in production from extensions and discoveries that were not reflected in our Proved Reserves at January 1, 2013. Also, our production included approximately 21.7 Bcfe from the Haynesville and Eagle Ford properties that were acquired during the year.

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, 2013:

	Mmcfe
Proved Undeveloped Reserves at January 1, 2013	37,130
Purchases of Proved Undeveloped reserves in place	195,830
Sales of Proved Undeveloped reserves	(50,932)
New discoveries and extensions (1)	46,667
Proved Undeveloped Reserves transferred to developed (2)	(64,277)
Proved Undeveloped Reserves transferred to unproved (3)	(3,825)
Other revisions of previous estimates of Proved Undeveloped Reserves (4)	226,361
Proved Undeveloped Reserves at December 31, 2013	386,954

(1) Approximately 51% and 30% of the discoveries and extensions of Proved Undeveloped Reserves in 2013 occurred in the Eagle Ford shale and Marcellus shale, respectively.

(2) Proved Undeveloped Reserves transferred to Proved Developed Reserves in 2013 were primarily in DeSoto Parish. Capital costs incurred to convert Proved Undeveloped Reserves to Proved Developed Reserves were $72.0 million.

(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 to certain conventional properties held by the EXCO/HGI Partnership in the Permian Basin. 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 upward revisions are due primarily to increased natural gas prices which resulted in the reclassification of unproved locations to Proved Undeveloped properties that became economical when using the prices prescribed by the SEC.

Impacts of changes in reserves on depletion rate and statements of operations in 2013

Our depletion rate decreased to $1.47 per Mcfe in 2013 from $1.52 per Mcfe in 2012. The decrease is primarily the result of significant ceiling test impairments during 2012, which lowered our depletable base. This was partially offset by an increase in our depletable base from the acquisition of the Haynesville and Eagle Ford assets and higher future development costs due to an increase in proved undeveloped reserves resulting from higher natural gas prices. We expect this rate to increase during 2014 as a result of a higher depletion rate associated with our oil producing assets in the South Texas region and the downward revisions of reserve quantities to our properties in the Haynesville shale during the fourth quarter of 2013.

Our production, prices and expenses

The following table summarizes revenues, net production, average sales price per unit and costs and expenses associated with the production of oil, natural gas and NGLs.

	Year Ended December 31,		
(in thousands, except production and per unit amounts)	**2013**	**2012**	**2011**
Revenues, production and prices:			
Oil:			
Revenue	$ 111,440	$ 62,119	$ 67,440
Production sold (Mbbl)	1,188	704	741
Average sales price per Bbl	$ 93.80	$ 88.24	$ 91.01
Natural gas liquids:			
Revenue	$ 8,560	$ 22,068	$ 29,639
Production sold (Mbbl)	243	510	505
Average sales price per Bbl	$ 35.23	$ 43.27	$ 58.69
Natural gas:			
Revenue	$ 514,309	$ 462,422	$ 657,122
Production sold (Mmcf)	153,321	182,644	176,700
Average sales price per Mcf	$ 3.35	$ 2.53	$ 3.72
Costs and Expenses:			
Average production costs per Mcfe (excluding severance and ad valorem taxes)	$ 0.38	$ 0.41	$ 0.46

We had one field that exceeded 15% of our total Proved Reserves as of December 31, 2013. Our Haynesville shale field represented approximately 65% of our total Proved Reserves. The following table provides additional information related to our Haynesville shale field:

	Year Ended December 31,		
	2013	**2012**	**2011**
Haynesville Shale:			
Natural gas production sold (Mmcf)	120,090	136,910	130,028
Average price per Mcf	$ 3.39	$ 2.47	$ 3.64
Average production cost per Mcf (excluding severance and ad valorem taxes)	0.15	0.12	0.08

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, 2013					
	Gross wells (1)			Net wells		
	Oil	Natural gas	Total	Oil	Natural gas	Total
Producing region:						
East Texas/North Louisiana	—	631	631	—	226.1	226.1
South Texas	157	4	161	91.0	2.1	93.1
Appalachia	330	5,850	6,180	161.1	2,645.1	2,806.2
Permian and other	2	24	26	1.0	5.7	6.7
EXCO/HGI Partnership	454	1,001	1,455	109.6	213.4	323.0
Total	943	7,510	8,453	362.7	3,092.4	3,455.1

(1) As of December 31, 2013, we held interests in 2 gross wells with multiple completions.

As of December 31, 2013, we were the operator of 7,863 gross (3,394.6 net) wells, which represented approximately 97.4% of our proved developed producing reserves.

Our drilling activities

Our drilling activities are primarily focused on horizontal drilling in shale plays, particularly in the Haynesville/Bossier, Eagle Ford and Marcellus shales. During 2013, we began drilling activities on the recently acquired properties in the Eagle Ford shale in South Texas. The following tables summarize our approximate gross and net interests in the operated 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, 2013, we had 4 gross (0.9 net) wells being drilled and 21 gross (4.4 net) wells being completed or awaiting completion.

	Development wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2013 (1)	105	2	107	48.7	0.5	49.2
Year ended December 31, 2012	169	2	171	73.8	1.9	75.7
Year ended December 31, 2011	255	2	257	116.9	1.9	118.8

	Exploratory wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2013 (2)	15	—	15	7.7	—	7.7
Year ended December 31, 2012	6	—	6	2.2	—	2.2
Year ended December 31, 2011	80	2	82	26.9	2.0	28.9

(1) Our development wells in 2013 included the Haynesville shale in DeSoto Parish and Southern Caddo Parish, Louisiana, the Eagle Ford shale in our core area in Zavala County, Texas, and the Marcellus shale in Armstrong and Lycoming Counties in Pennsylvania. Additionally, the EXCO/HGI Partnership's development wells in 2013 included shallow conventional properties in the Permian Basin. The dry holes drilled during 2013 included shallow conventional properties held by the EXCO/HGI Partnership in the Permian Basin.

(2) Our exploratory wells in 2013 included certain wells drilled in the Eagle Ford shale under the farmout agreement with Chesapeake outside of our core area in Zavala County, Texas and certain wells in the Marcellus shale in Jefferson, Clarion 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, 2013			
	Developed		Undeveloped	
Area	Gross	Net	Gross	Net
East Texas/North Louisiana	148,100	70,300	41,200	16,700
South Texas (1)	87,700	44,300	9,300	3,500
Appalachia	376,700	171,000	295,800	119,400
Permian and other	6,200	4,400	23,300	13,800
Total	618,700	290,000	369,600	153,400
EXCO/HGI Partnership (2)	170,000	37,600	9,200	1,800

(1) Our acreage in the South Texas region does not include the undeveloped locations associated with the farmout agreement with Chesapeake.

(2) The net acreage reported for the EXCO/HGI Partnership represents our 25.5% economic interest. The acreage reported for the EXCO/HGI Partnership primarily consists of shallow rights in the same acreage for which EXCO owns the deep rights.

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 5,600, 27,500 and 9,600 net acres with leases expiring in 2014, 2015 and 2016, respectively. Approximately 70% of the scheduled expiring acreage is located within our shale resource plays. We are currently evaluating plans to drill on this acreage or extend the term of the leases.

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.

Our significant customers

In 2013, sales to BG Energy Merchants LLC and Chesapeake Energy Marketing Inc. accounted for approximately 48% and 14%, respectively, of total consolidated revenues. BG Energy Merchants LLC is a subsidiary of BG Group, plc ("BG Group") and Chesapeake Energy Marketing Inc. is a subsidiary of Chesapeake. The loss of any significant customer may cause a temporary interruption in sales of, or lower price for, our oil and natural gas. However, 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 ("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 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 ("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 ("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 ("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 ("DOT") under the Hazardous Liquid Pipeline Safety Act of 1979, as amended ("HLPSA") with respect to oil, and the Natural Gas Pipeline Safety Act of 1968, as amended ("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 ("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 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 ("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 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 ("OPA");
- the Clean Water Act of 1972 ("CWA");
- the Rivers and Harbors Act of 1899;
- the Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA");
- the Resource Conservation and Recovery Act ("RCRA");
- the Clean Air Act ("CAA"); and
- the Safe Drinking Water Act ("SDWA").

In general, the oil and gas exploration and production industry has been the subject of increasing scrutiny and regulation by environmental authorities. For example, the United States Environmental Protection Agency (“EPA”) has identified environmental compliance by the energy extraction section as one of its enforcement initiatives for 2014-2016.

Our domestic activities are subject to regulations promulgated under federal 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, restrict the types of substances used in our drilling operations, 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 ("PRPs") include the current and certain past owners and operators of a facility where there has been a release or threat of release of a hazardous substance and persons who disposed of or arranged for the disposal of hazardous substances found at a site. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the cost of such action. Liability can arise from conditions on properties where operations are conducted, even under circumstances where such operations were performed by third parties not under our control, and/or from conditions at third party disposal facilities where wastes from operations were sent. Although CERCLA currently exempts petroleum (including oil, natural gas and NGLs) from the definition of hazardous substance, some similar state statutes do not provide such an exemption. We cannot 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 suspend or 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 ("NSPS"), and National Emission Standards for Hazardous Air Pollutants ("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 ("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 continuously evaluate the effect these rules and amendments 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 ("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.

The EPA has adopted rules that require new major sources and major modifications of GHG to obtain its so-called GHG “tailoring” rule that will phase in federal prevention of significant deterioration (“PSD”) permits, Major sources of GHG also have to obtain Title V operating permits. Those rules including the “tailoring” rule which limits the number of GHG sources subject to these permitting requirements by raising the threshold levels for what constitutes a major source of GHG. 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. The EPA established 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. 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. 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 ("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 Texas, also have coastal management programs, which provide for, among other things, the coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development. Coastal management programs also may provide for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the state coastal management plan. In the event our activities trigger these programs, this review of agency rules and actions may impact other agency permitting and review activities, resulting in possible delays or restrictions of our activities and adding an additional layer of review to certain activities undertaken by us.

The Endangered Species Act (“ESA”) was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species’ habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service must also designate the species’ critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If the Company were to have a portion of its leases designated as critical or suitable habitat, it may adversely impact the value of the affected leases.

Hydraulic fracturing activities

Over the past few years, there has been an increased focus on environmental aspects of hydraulic fracturing activities in the United States. While hydraulic fracturing is typically regulated by state oil and natural gas commissions in the United States, there have recently been a number of regulatory initiatives at the federal and local levels as well as by other state agencies.

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 South Texas, East Texas, North Louisiana and Appalachia. 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 and has issued guidance regarding its authority over the permitting of these activities. 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. This study remains subject to review. The agency also announced that one of its enforcement initiatives for 2014 to 2016 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.

Additionally, the Bureau of Land Management has proposed regulations on hydraulic fracturing activities on Federal land. The EPA has also announced an initiative under the Toxic Substances Control Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals, and is working on regulations governing wastewater generated by hydraulic fracturing. 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 ("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 $25 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 $50,000 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, 2013, we employed 755 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 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended ("the Exchange Act"). These forward-looking statements relate to, among other things, the following:

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

We have based these forward-looking statements on our current assumptions, expectations and projections about future events. We use the words “may,” “expect,” “anticipate,” “estimate,” “believe,” “continue,” “intend,” “plan,” “budget” and other similar words to identify forward-looking statements. The statements that contain these words should be read carefully because they discuss future expectations, contain projections of results of operations or 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 applicable securities laws. These statements also involve risks and uncertainties that could cause our actual results or financial condition to materially differ from our expectations in this prospectus and the documents incorporated herein by reference, including, but not limited to:

- fluctuations in the prices of oil, natural gas and natural gas liquids;
- the availability of foreign oil, natural gas and natural gas liquids;
- future capital requirements and availability of financing;
- our ability to meet our current and future debt service obligations;
- 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, primarily related to our activities in shale formations, including the Eagle Ford shale play in South Texas;
- 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;
- availability of water for drilling and hydraulic fracturing activities;
- 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;
- our ability to manage joint ventures with third parties, including the resolution of any material disagreements and our partners' ability to satisfy obligations under these arrangements;
- 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. We caution users of the financial statements not to place undue reliance on any forward-looking statements. When considering our forward-looking statements, 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 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 "Risk Factors" for a discussion of certain risks related to our business, indebtedness and common stock.

Our revenues, operating results and financial condition depend substantially on prevailing prices for oil and natural gas and the availability of capital from the EXCO Resources 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 to 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 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) same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) same environment of deposition; (iii) similar geological structure; and (iv) 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.

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 method. 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.

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. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well.

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.

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.

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 of natural gas 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 of natural gas 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 **t**he sum of fractional ownership interests owned in gross acres or gross wells equals one. We compute the number of net wells by totaling the percentage interest we hold in all our gross wells.

NYMEX. New York Mercantile Exchange.

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

Overriding royalty interest. An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of 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 method. 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. Proved oil and natural gas reserves are 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, Reasonable Certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery ("EUR") with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

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

Resources. Resources are quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

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 spot prices for the trailing 12 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 for 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 and natural gas regardless of whether such acreage contains Proved Reserves.

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

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

Available information

We make 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

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, 2013, approximately 90% of our Proved Reserves were natural gas and approximately 95% 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 oil and natural gas have been extremely volatile, and we expect this volatility to continue. During 2013, the NYMEX price for natural gas fluctuated from a high of $4.46 per Mmbtu to a low of $3.11 per Mmbtu, while the NYMEX West Texas Intermediate crude oil price ranged from a high of $110.53 per Bbl to a low of $86.68 per Bbl. For the five years ended December 31, 2013, the NYMEX Henry Hub natural gas price ranged from a high of $6.07 per Mmbtu to a low of $1.91 per Mmbtu, while the NYMEX West Texas Intermediate crude oil price ranged from a high of $113.93 per Bbl to a low of $33.98 per Bbl. On December 31, 2013, the spot market price for natural gas at Henry Hub was $4.23 per Mmbtu, a 26% increase from December 31, 2012. On December 31, 2013, the spot market price for crude oil at Cushing was $98.42 per Bbl, a 7% increase from December 31, 2012. For 2013, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were $93.80 per Bbl and $3.35 per Mcf, respectively, compared with 2012 average realized prices of $88.24 per Bbl and $2.53 per Mcf, respectively.

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

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

The reference or regional index prices that we use to price our oil and natural gas sales sometimes reflect a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we reference in our sales contracts is called a differential. We cannot accurately predict oil and natural gas differentials. Changes in differentials between the benchmark price for oil and natural gas and the reference or regional index price we reference in our sales contracts could have a material adverse effect on our results of operations and financial condition. We have recently experienced significant volatility in our price differentials including crude oil production from the Eagle Ford shale and natural gas production in certain areas in Appalachia. Our crude oil production from the Eagle Ford shale is currently sold at a price based on the Phillips 66 West Texas Intermediate index plus or minus the differential to the Argus Louisiana Light Sweet index. During 2013, this differential ranged from a high of $21.98 per barrel to a low of $2.20 per barrel. Our natural gas production from the Marcellus shale in Northeast Pennsylvania is sold at a price based on a Platts index that represents value into the Transco Leidy Pipeline. Due to the increased production in this region without an offsetting increase in pipeline capacity or infrastructure to the Northeast United States markets, this differential in 2013 ranged from a high of NYMEX less $0.02 per Mmbtu to a low of NYMEX less $1.86 per Mmbtu. These differentials vary depending on factors such as supply, demand, pipeline capacity, infrastructure, and weather.

There are risks associated with our drilling activity that could impact our results of operations and financial condition.

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. Also, we may experience issues with the availability of water used in our drilling and hydraulic fracturing activities. All of these risks could adversely affect our results of operations and financial condition.

Our ability to develop properties in new or emerging formations may be subject to more uncertainties than drilling in areas that are more developed or have a longer history of established production.

The results of our drilling in new or emerging formations, including the Eagle Ford shale formation, are more uncertain initially than drilling results in areas that are developed, have established production or where we have a longer history of operation. Because new or emerging formations have limited or no production history, we are less able to use past drilling results in those areas to help predict future drilling results. Further, part of our strategy for the Eagle Ford shale formation involves the use of horizontal drilling and completion techniques that have been successful in other shale formations. Our experience with horizontal drilling in these areas to date, as well as the industry's drilling and production history, while growing, is limited. The ultimate success of these drilling and completion techniques will be better evaluated over time as more wells are drilled and production profiles are better established.

If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, and/or natural gas and oil prices decline, our investment in these areas may not be as attractive as we anticipate and we could incur material impairments of undeveloped properties and the value of our undeveloped acreage could decline in the future, which could have a material adverse effect on our business and results of operations.

Market conditions or operational impediments, such as lack of available transportation or infrastructure, may hinder our production or adversely impact our ability to receive market prices for our production or to achieve expected drilling results.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements or infrastructure may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines, processing facilities and oil and condensate trucking operations owned and operated by third-parties. Our failure to obtain these services on acceptable terms could have a material adverse effect on our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines, gathering systems or trucking capacity. A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, excessive pressures, maintenance, weather, field labor issues or other disruptions of service. Curtailments and disruptions may last from a few days to several months, and we have no control over when or if third-party facilities are restored.

In the past we have experienced production curtailments due to infrastructure and market constraints in the Eagle Ford shale formation, which has caused natural gas production to either be shut in or flared. Any significant curtailment in gathering, processing or pipeline system capacity, significant delay in the construction of necessary facilities or lack of availability of transportation would interfere with our ability to market our oil and natural gas production, and could have a material adverse effect on our cash flow and results of operations.

We depend on Chesapeake to market our oil and natural gas production in the Eagle Ford shale. If Chesapeake is unable or otherwise fails to market our Eagle Ford production, our revenues could be adversely affected.

We have entered into marketing agreements with an affiliate of Chesapeake to sell all of the anticipated oil and natural gas production associated with the acreage we acquired from Chesapeake in the Eagle Ford shale formation. If Chesapeake is unable or otherwise fails to market the oil and natural gas we produce from the Eagle Ford shale formation, we would be required to find alternate means to market our production, which could increase our costs, reduce the revenues we might obtain from the sale of our oil and natural gas or have a material adverse effect on our business, results of operations or financial condition.

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

We conduct a substantial portion of our operations through joint ventures with third parties, principally BG Group, HGI and KKR, 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 development costs pertaining to the joint venture and their share of 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, we are required to present opportunities related to the development of certain conventional assets to the EXCO/HGI Partnership. BG Group also has the right to elect to participate in all acreage and other acquisitions in defined areas of mutual interest in the Haynesville and Appalachia regions. 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.

We may make significant capital expenditures and be subject to certain legal and financial terms as the result of our joint ventures with BG Group that could adversely affect us.

We are a party 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 operates as a joint venture pursuant to a joint development agreement under which EXCO acts as the operator.

We are also party to a joint venture with BG Group covering our Marcellus shale acreage and shallow producing assets in the Appalachia region ("Appalachia JV"). 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 the operating entity that operates the Appalachia JV's 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 a midstream joint venture in Appalachia 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:

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

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, 2013 and 2012, we received cash receipts to settle our derivative financial instrument contracts totaling $42.1 million and $202.1 million, respectively. For the year ended December 31, 2013, 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 $91.9 million. As of December 31, 2013, our oil and natural gas derivative financial instrument contracts were in the net liability position of $6.5 million. The ultimate settlement amount of these unrealized derivative financial instrument contracts is dependent on future commodity prices. We may incur significant realized and 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.

To fund the acquisitions of oil and natural gas assets in the Haynesville and Eagle Ford shale formations, we incurred 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.

To finance the acquisitions of the oil and natural gas assets in the Haynesville and Eagle Ford shale formations from Chesapeake, we entered into the amended EXCO Resources Credit Agreement on July 31, 2013. As of January 31, 2014, the revolving commitment under the EXCO Resources Credit Agreement had an available borrowing base of approximately $900.0 million, with approximately $491.0 million of outstanding indebtedness and $402.1 million of unused borrowing base, net of letters of credit.

Our business may not generate sufficient cash flow from operations to enable us to repay our indebtedness, including our 7.5% senior unsecured notes due September 15, 2018 ("2018 Notes") and the EXCO Resources Credit Agreement, to fund planned capital expenditures and to fund our other liquidity needs. If our cash flow, capital resources and planned asset sales are insufficient to repay our debt obligations and finance capital expenditure programs, we may be forced to sell additional assets, issue additional equity or debt securities or restructure our indebtedness. These options may not be available on commercially reasonable terms, or at all. In addition, the sale of assets or issuance of debt securities would have to be completed in compliance with the financial and other restrictive covenants in the EXCO Resources Credit Agreement and the indenture governing the 2018 Notes.

If we cannot make scheduled payments on our indebtedness, 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. Further, failing to comply with the financial and other restrictive covenants in the EXCO Resources Credit Agreement or the indenture governing the 2018 Notes could result in an event of default, which could adversely affect our business, financial condition and results of operations.

If we are unable to complete the joint development of our assets in the Eagle Ford shale formations with KKR, we may need to find alternative sources of capital, which may not be available on favorable terms, or at all.

On July 31, 2013, we closed the acquisition of certain producing and non-producing oil, natural gas and mineral leases and wells in the Eagle Ford shale located in Zavala, Dimmit and Frio counties in South Texas. In connection with the closing of the acquisition of the Eagle Ford assets, we sold an undivided 50% interest in the undeveloped acreage to affiliates of KKR for approximately $130.9 million. With respect to each well drilled, EXCO will assign half of its undivided 50% interest in such well to KKR such that KKR will fund and own 75% of each well drilled and EXCO will fund and own 25% of each well drilled. There can be no assurance that KKR will elect to proceed with subsequent phases of the development of our Eagle Ford assets. If we cannot identify an alternative joint venture partner or partners for our Eagle Ford assets, sell assets at acceptable valuations or are unable to complete the joint development of our Eagle Ford assets, we will need to utilize cash flow from other operations or will need to find alternative sources of capital to finance the development of the Eagle Ford assets, which may slow the development of these assets and have a material adverse effect on our operations and prospects.

While we are required to make offers to purchase KKR's interest in certain wells, we may not have sufficient funds or borrowing capacity under the EXCO Resources Credit Agreement to complete the acquisitions pursuant to the KKR Participation Agreement. In the event we fail to purchase a group of wells that KKR is obligated to sell, there are remedies available to KKR which allow KKR to reject future EXCO offers, terminate the KKR Participation Agreement, or pursue other legal remedies. This could require us to seek alternative financing to make offers to preserve KKR's obligation to sell to us, or negatively impact our ability to increase our Eagle Ford assets via acquisitions of KKR's producing properties.

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

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

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.

Acquisitions, development drilling and exploration drilling 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 indemnification we receive from sellers may be insufficient to protect us from such risks, which may result in unexpected liabilities and costs to us.

Generally, it is not feasible for us to review in detail every individual property involved in an acquisition. Our business strategy focuses on acquisitions of producing oil and natural gas properties. Any future acquisitions will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards and liabilities, potential tax and Employee Retirement Income Security Act of 1974 liabilities, other liabilities and 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 fully assess 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 from acquisitions could result in material liabilities and costs that could 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 indemnify us against all or part of these problems. Even if a seller agrees to provide indemnification, the indemnification may not be fully enforceable and may be limited by floors and caps on such indemnification.

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

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. The use of firm transportation agreements allows us priority space in a shippers' pipeline. In the event the quantities delivered under these arrangements are significantly below the minimum volumes within the agreements, it could adversely affect our business, financial condition and results of operations.

In addition, we have also entered into a marketing agreement with respect to our Haynesville production whereby we are required to deliver a minimum amount of natural gas from the Haynesville shale. We will be required to make material expenditures for these agreements if we fail to deliver the required quantities of natural gas in the future. To the extent that we do not produce and deliver sufficient natural gas production, the requirements to pay for quantities not delivered could have a material impact on our results of operations and liquidity.

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 gathering systems, pipelines and other transportation facilities. We are primarily dependent upon third parties to transport our products. Transportation space on the gathering systems and pipelines we utilize is occasionally limited or unavailable due to repairs, outages caused by accidents or other events, or improvements to facilities or due to space being utilized by other companies that have priority transportation agreements. We 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 success will depend on the success of our acquisition, exploration, development and exploitation activities. Our decisions to purchase, explore, develop or otherwise exploit properties or prospects will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. These decisions 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 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 of our Proved Reserves. These estimates are based upon reports of our independent petroleum engineers. These reports rely upon various assumptions, including assumptions required by the Securities and Exchange Commission ("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 and such estimates prepared by different engineers or by the same engineers at different times, may vary substantially.

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, decisions and assumptions made by engineers 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 negatively affect 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 Texas, North Louisiana and Appalachia. 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 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.

Certain 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.

The Obama administration's budget proposals for fiscal year 2014 contain numerous proposed tax changes, and from time to time, legislation has been introduced that would enact many of these proposed changes. The proposed budget and legislation would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and impose new fees. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the domestic manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing federal oil and gas leases. The passage of legislation containing some or all of these provisions or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and natural gas exploration and development, and any such change could have a material adverse effect on our business, 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 GHGs for the present appears unlikely, the EPA has been implementing regulations under existing CAA authority, some of which 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.

The EPA has adopted GHG rules that require federal prevention of significant deterioration 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 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. The EPA has also adopted rules 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. We are subject to these rules and the applicable GHG reporting requirements. Although these rules do not limit the amount of GHGs that can be emitted, they require us to incur costs to monitor, recordkeep 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, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act"). The Dodd-Frank Act establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in the market and requires the Commodities Future Trading Commission ("CFTC"), federal regulators of banks and other financial institutions and the SEC to implement the new law by promulgating regulations relating to derivatives transactions, including the derivatives transactions we use to hedge our exposure to commodity price volatility. Under the Dodd-Frank Act and related reforms, over-the-counter derivatives dealers and other over-the-counter major market participants could be subjected to substantial regulatory supervision. The reforms expand the power of the CFTC to regulate derivatives transactions related to energy commodities, including oil and natural gas, to mandate clearance of derivatives contracts through registered derivatives clearing organizations and to impose burdensome capital and margin requirements and business conduct standards on over-the-counter derivatives transactions.

The Dodd-Frank Act also permits the CFTC to set position limits on certain derivatives instruments. In October 2011, the CFTC issued a rule to implement position limits for certain futures and options contracts on certain commodities and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions). Following a challenge in federal court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association, the CFTC's rule on position limits was vacated by the U.S. District Court for the District of Columbia in September 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, such position limits have not yet taken effect, although the CFTC did issue a new set of proposed position limit rules in November 2013 and has taken the position that the Dodd-Frank

Act requires the CFTC to impose such 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 such position limits, which may reduce our ability to enter into hedging transactions.

The reforms may also require us to comply with margin and clearing and trade-execution requirements in connection with our derivatives activities, although whether and the extent to which these requirements will apply to our business is uncertain at this time. Further, the reforms may also require our counterparties to spin off derivatives activities to separate entities which may not be as creditworthy as the original counterparties.

The full impact of the Dodd-Frank Act and related reforms and regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. If the reforms ultimately require that we post margin for our hedging activities or require our counterparties to hold margin or maintain required minimum capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome that current regulations, hedges could become significantly more expensive (including through requirements to post collateral, which could adversely affect available liquidity), uneconomic or unavailable, which could lead to increased costs, commodity price volatility, reductions in commodity prices, or any combination of the foregoing. Further, such developments could reduce our ability to monetize or restructure our existing derivatives contracts, subject us to additional capital or margin requirements, restrict our flexibility in conducting trading activity and taking commodity positions, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives 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. In addition, the Dodd-Frank Act 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 lower commodity prices. Individually and collectively, these factors could have a material adverse effect on our ability to hedge risks and on our business, financial condition or results of operations.

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

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Most hydraulic fracturing (other than hydraulic fracturing using diesel) is exempted from regulation under the SDWA. 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. At the state and local levels, some jurisdictions have adopted, and others are considering adopting, requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities, as well as bans on hydraulic fracturing activities. In the event that new or more stringent state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we have properties, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

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 ("UIC"). 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. Interim results of the study are expected in 2012, with final results expected in 2014. The agency also announced that one of its enforcement initiatives for 2014 through 2016 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.

In addition, the EPA recently issued guidance under the SDWA providing direction on how it will address the use of diesel in hydraulic fracturing activities and how its UIC will be applied to such hydraulic fracturing activities. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. The Bureau of Land Management has proposed draft rules to regulate hydraulic fracturing on federal lands and the EPA has announced an initiative under the Toxic Substances Control Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals. If hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operations restrictions and also to associated permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we ultimately are able to produce.

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

Our operations are subject to numerous complex 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. Laws, rules and regulations protecting the environment have changed frequently and the changes often include increasingly stringent requirements. We could incur material costs, including clean-up costs, fines and civil and criminal sanctions (including injunctive relief) 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 gas industry through its GHG, CAA and SDWA regulations.

The EPA has adopted rules subjecting oil and natural gas operations to regulation under the New Source Performance Standards ("NSPS"), and the National Emissions Standards for Hazardous Air Pollutants, ("NESHAPS"), programs under the CAA, and imposing new and amended requirements under both programs. Among other things, the rule amends standards applicable to natural gas processing plants and expands the NSPS to include all oil and natural gas operations, imposing requirements on those operations. The rule also imposes NSPS standards for completions of hydraulically fractured natural gas wells. These standards include the reduced emission completion techniques. The NESHAPS also includes maximum achievable control technology standards for certain glycol dehydrators and storage vessels, and revises applicability provisions, alternative test protocols and the availability of the startup, shutdown and maintenance exemption. The implementation of these new requirements may result in increased operating and compliance costs, increased regulatory burdens and delays in our operations.

We may have impairments 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 record an impairment to the value of our oil and natural gas properties if the present value of the after-tax future cash flows from our oil and natural gas properties falls below the net book value of these properties. We have in the past experienced, and may experience in the future, ceiling test impairments with respect to our oil and natural gas properties.

Given the short passage of time between the closing of the acquisition of Haynesville and Eagle Ford assets from Chesapeake during July 2013 and the required ceiling test computation, we requested, and received, an exemption from the SEC to exclude these acquired properties from the ceiling test assessments for a period of 12 months following the corresponding acquisition dates. The request for exemption was made because the ceiling test requires companies using the full cost accounting method to price period ending Proved Reserves using the simple average spot price for the trailing 12 month period, which may not be indicative of actual market values. We will assess these acquisitions for impairment during the requested exemption period. Further, if we cannot demonstrate that fair value exceeds the unamortized carrying costs during the requested exemption periods prior to issuance of our financial statements, we are required to recognize an impairment.

Our evaluation of impairment is based upon estimates of Proved Reserves. The value of our Proved Reserves may be lowered in future periods as a result of a decline in prices of oil and natural gas, a downward revision of our oil and natural gas reserves or other factors. As a result, our evaluation of impairment for future periods is subject to 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. Because several of these factors are beyond our control, we cannot accurately predict or control the amount of ceiling test impairments in future periods. Future ceiling test impairments could negatively affect our results of operations and net worth.

For the years ended December 31, 2013, 2012, and 2011 we recognized impairments of $108.5 million, $1.3 billion and $233.2 million, respectively, to our proved oil and natural gas properties. We may have additional impairments of our oil and natural gas properties in future periods if the cost of our unamortized proved oil and natural gas properties exceeds the limitation under the full cost method of accounting.

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. As a result of our testing of goodwill for impairment, we did not record an impairment charge for the periods ended December 31, 2013, 2012 and 2011.

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

Our ability to collect payments from the sale of oil and natural gas to our customers depends on the payment ability of our customer base, which includes several significant customers. If any one or more of our significant customers fails to pay us for any reason, we could experience a material loss. In addition, in recent years, it has become more difficult to maintain and grow a customer base of creditworthy customers because a number of energy marketing and trading companies have discontinued their marketing and trading operations, which has significantly reduced the number of potential purchasers for our oil and natural gas production. As a result, we may experience a material loss as a result of the failure of our customers to pay us for prior purchases of our oil or natural gas.

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

For 2013, sales to BG Energy Merchants LLC accounted for approximately 48% of total consolidated revenues. BG Energy Merchants LLC is a subsidiary of BG Group. In addition, approximately 14% of our total consolidated revenues were to Chesapeake Energy Marketing Inc. Chesapeake Energy Marketing Inc. is a subsidiary of Chesapeake. The loss of any significant customer may cause a temporary interruption in sales of, or a lower price for, our oil and natural gas.

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

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have greater financial and technical resources and a larger headcount 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 has also been strong in hiring experienced personnel, particularly in petroleum engineering, geoscience, accounting and financial reporting, tax and land professions. In addition, competition is strong for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights. We are often outbid by competitors in our attempts to acquire properties or companies. All of these challenges could make it more difficult to execute our growth strategy.

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

We depend upon third party pipelines and other facilities 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 are currently involved in a search for a new chief executive officer and if this search is delayed or if we were to lose the services of other key personnel, our business could be negatively impacted.

On November 20, 2013, Douglas H. Miller resigned from the positions of chief executive officer, chairman of the board of directors and as a director. Our board of directors appointed Jeffrey D. Benjamin to serve as non-executive chairman of the board of directors and initiated a search to identify a new chief executive officer. To the extent there is a delay in choosing a new chief executive officer, our business could be negatively impacted. In addition, our future success depends in part upon the continued service of key members of our senior management team. Our senior management team is critical to our management and they also play a key role in maintaining our culture and setting our strategic direction. All of our executive officers and key employees are at-will employees. The loss of key personnel could seriously harm our business.

Our ability to use net operating loss carryovers to reduce future tax payments may be limited.

Our net operating loss and other tax attribute carryovers ("NOLs") may be limited if we undergo an ownership change. Generally, an ownership change occurs if certain persons or groups increase their aggregate ownership in us by more than 50 percentage points looking back over a rolling three-year period. If an ownership change occurs, our ability to use our NOLs to reduce income taxes is limited to an annual amount, or the Section 382 limitation, equal to the fair market value of our common stock immediately prior to the ownership change multiplied by the long term tax-exempt interest rate, which is published monthly by the IRS. In the event of an ownership change, NOLs can be used to offset taxable income for years within a carryforward period subject to the Section 382 limitation. Any excess NOLs that exceed the Section 382 limitation in any year will continue to be allowed as carryforwards for the remainder of the carryforward period. Whether or not an ownership change occurs, the carryforward period for NOLs is 20 years from the year in which the losses giving rise to the NOLs were incurred. If the carryforward period for any NOL were to expire before that NOL had been fully utilized, the unused portion of that NOL would be lost. Our use of new NOLs arising after the date of an ownership change would not be affected by the Section 382 limitation (unless there is another ownership change after the new NOLs arise).

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 production company, 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.

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

While we have taken actions designed to address compliance with the internal control, disclosure control and other requirements of the Sarbanes-Oxley Act of 2002, as amended, and the rules and regulations promulgated by the SEC implementing these requirements, there are inherent limitations in our ability to control all circumstances. Our management, including our chief financial officer and interim chief accounting officer, does not expect that our internal controls and disclosure controls 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, such as growth of our company or increased transaction volume, or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Certain of our undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on the acreage.

Leases on oil and natural gas properties typically have a term after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. While we seek to actively manage our leasehold inventory through drilling wells to hold the leasehold acreage that we believe is material to our operations, our drilling plans for these areas are subject to change.

Potential physical effects of climate change could adversely affect our operations and cause us to incur significant costs in preparing for or responding to those effects.

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations, including the hydraulic fracturing of our wells, have the potential to be adversely affected. Potential adverse effects could include disruption of our production activities, including, for example, damages to our facilities from powerful winds or increases in our costs of operation or reductions in the efficiency of our operations, as well as potentially increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

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 January 31, 2014 we had approximately $1.5 billion of indebtedness, excluding our proportionate share of indebtedness for the EXCO/HGI Partnership, including $789.5 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 and our proportionate share of interest expense for the EXCO/HGI Partnership, on an annual basis based on currently available interest rates would be approximately $83.0 million and would change by approximately $5.4 million for every 1% change in interest rates.

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

- it may be more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the EXCO Resources Credit Agreement or the indenture governing the 2018 Notes ("Indenture"), and the agreements governing our other indebtedness;
- we may have difficulty borrowing money in the future for acquisitions (including obligations to acquire interests in wells pursuant to the KKR Participation Agreement), 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 more money or raise equity on terms acceptable to us, if at all and may be required to surrender assets pursuant to the security provisions of the EXCO Resources Credit Agreement. Further, failing to comply with the financial and other restrictive covenants in the EXCO Resources Credit Agreement and the Indenture could result in an event of default, which could adversely affect our business, financial condition and results of operations.

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

Together with our subsidiaries, we may incur substantially more debt in the future in connection with our exploration, exploitation, development, acquisitions of undeveloped acreage and 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, fund our planned capital expenditure programs and fund acquisitions under the KKR Participation Agreement, 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, issue additional equity or debt securities 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. 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 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 12 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 common stock price may fluctuate significantly.

Our common stock trades on the NYSE but an active trading market for our common stock may not be sustained. The market price of shares of our common stock could fluctuate significantly as a result of:

- announcements relating to our business or the business of our competitors;
- changes in expectations as to our future financial performance or changes in financial estimates of public market analysis;
- actual or anticipated quarterly variations in our operating results;
- 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 permits 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 shares of 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.

Oaktree Capital Management, WL Ross & Co. LLC and/or their respective affiliates have significant influence over matters requiring shareholder approval because of their ownership of our common stock.

As of January 17, 2014, Oaktree Capital Management, L.P. ("Oaktree"), and WL Ross & Co. LLC ("WL Ross"), directly or through certain affiliates, beneficially owned approximately 16.6% and 18.7%, respectively, of our outstanding shares of common stock. The beneficial ownership of Oaktree and WL Ross and/or their affiliates provides them with significant influence regarding matters submitted for shareholder approval, including proposals regarding:

- any merger, consolidation or sale of all or substantially all of our assets;
- the election of members of our board of directors; and
- any amendment to our articles of incorporation.

The current or increased ownership position of Oaktree, WL Ross and/or their respective affiliates could delay, deter or prevent a change of control or adversely affect the price that investors might be willing to pay in the future for shares of our common stock. The interests of Oaktree, WL Ross, and/or their respective affiliates may significantly differ from the interests of our other shareholders and they may vote the shares of common stock they beneficially own in ways with which our other shareholders disagree.

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	$ 352,500	December 31, 2015
Warrendale, Pennsylvania	56,000	$ 112,000	October 31, 2016
Cranberry Township, Pennsylvania	22,300	$ 29,100	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
2013			
First Quarter	$ 7.92	$ 5.97	$ 0.05
Second Quarter	8.70	6.52	0.05
Third Quarter	9.00	6.63	0.05
Fourth Quarter	7.25	4.83	0.05
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

Our shareholders

According to our transfer agent, Continental Stock Transfer & Trust Company, there were 263 holders of record of our common stock on December 31, 2013 (including nominee holders such as banks and brokerage firms who hold shares for beneficial holders and the restricted stock shareholders).

Our dividend policy

In 2013, we paid cash dividends of $0.20 per share ($0.05 per quarter) totaling $43.2 million. Any future declaration of dividends, as well as the establishment of record and payment dates, is subject to limitations under the EXCO Resources Credit Agreement, 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, 2013:

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 (in millions) (1)
October 1, 2013 - October 31, 2013	—	$ —	—	$ 192.5
November 1, 2013 - November 30, 2013	—	—	—	192.5
December 1, 2013 - December 31, 2013	—	—	—	192.5
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. This financial data should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," our consolidated financial statements, the notes to our consolidated financial statements and the other financial information included in this Annual Report on Form 10-K. This information does not replace the consolidated financial statements.

Selected consolidated financial and operating data

	Year Ended December 31,				
(in thousands, except per share amounts)	2013	2012	2011	2010	2009
Statement of operations data (1):					
Revenues:					
Oil and natural gas	$ 634,309	$ 546,609	$ 754,201	$ 515,226	$ 550,505
Midstream (2)	—	—	—	—	35,330
Total revenues	634,309	546,609	754,201	515,226	585,835
Cost and expenses:					
Oil and natural gas production (3)	83,248	104,610	108,641	108,184	177,629
Midstream operating (2)	—	—	—	—	35,580
Gathering and transportation	100,645	102,875	86,881	54,877	18,960
Depletion, depreciation and amortization	245,775	303,156	362,956	196,963	221,438
Impairment of oil and natural gas properties	108,546	1,346,749	233,239	—	1,293,579
Accretion of discount on asset retirement obligations	2,514	3,887	3,652	3,758	7,132
General and administrative (4)	91,878	83,818	104,618	105,114	99,177
(Gain) loss on divestitures and other operating items (5)	(177,518)	17,029	23,819	(509,872)	(676,434)
Total cost and expenses	455,088	1,962,124	923,806	(40,976)	1,177,061
Operating income (loss)	179,221	(1,415,515)	(169,605)	556,202	(591,226)
Other income (expense):					
Interest expense, net	(102,589)	(73,492)	(61,023)	(45,533)	(147,161)
Gain (loss) on derivative financial instruments (6)	(320)	66,133	219,730	146,516	232,025
Other income (expense)	(828)	969	788	327	126
Equity income (loss) (2)	(53,280)	28,620	32,706	16,022	(69)
Total other income (expense)	(157,017)	22,230	192,201	117,332	84,921
Income (loss) before income taxes	22,204	(1,393,285)	22,596	673,534	(506,305)
Income tax expense	—	—	—	1,608	9,501
Net income (loss)	$ 22,204	$(1,393,285)	$ 22,596	$ 671,926	$ (496,804)
Basic net income (loss) per share	$ 0.10	$ (6.50)	$ 0.11	$ 3.16	$ (2.35)
Diluted net income (loss) per share	$ 0.10	$ (6.50)	$ 0.10	$ 3.11	$ (2.35)
Cash dividends declared per share	$ 0.20	$ 0.16	$ 0.16	$ 0.14	$ 0.05
Weighted average common shares and common share equivalents outstanding:					
Basic	215,011	214,321	213,908	212,465	211,266
Diluted	230,912	214,321	216,705	215,735	211,266
Statement of cash flow data:					
Net cash provided by (used in):					

Operating activities	$ 350,634	$ 514,786	$ 428,543	$ 339,921	$ 433,605
Investing activities	(252,478)	(427,094)	(709,531)	(712,854)	1,235,275
Financing activities	(93,317)	(74,045)	268,756	348,755	(1,657,612)
Balance sheet data:					
Current assets	$ 305,854	$ 361,866	$ 678,008	$ 520,460	$ 402,088
Total assets	2,408,628	2,323,732	3,791,587	3,477,420	2,358,894
Current liabilities	349,170	237,931	287,399	285,698	212,914
Long-term debt	1,858,912	1,848,972	1,887,828	1,588,269	1,196,277
Shareholders' equity	147,905	149,393	1,558,332	1,540,552	859,588
Total liabilities and shareholders' equity	2,408,628	2,323,732	3,791,587	3,477,420	2,358,894

(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 were accounted for using the equity method. On November 15, 2013, we sold our equity interest in TGGT to Azure in exchange for cash proceeds and an equity interest in Azure. We report our equity interest acquired in Azure using the cost method of accounting.

(3) Share-based compensation calculated pursuant to FASB Accounting Standards Codification 718, *Compensation-Stock Compensation* ("ASC 718") included in oil and natural gas production costs was $0.1 million, $1.0 million and $2.8 million for the years ended December 31, 2011, 2010 and 2009, respectively. We had no share-based compensation included in oil and natural gas production costs for the years ended December 31, 2013 and 2012.

(4) Share-based compensation calculated pursuant to ASC 718 included in general and administrative expenses was $10.7 million, $8.9 million, $10.9 million, $15.8 million and $16.2 million for the years ended December 31, 2013, 2012, 2011, 2010 and 2009, respectively.

(5) During 2013, we recognized a gain on the contribution of properties to the EXCO/HGI Partnership. During 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 exploitation, exploration, acquisition, 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 Texas, Louisiana and the Appalachia region.

Our primary strategy focuses on the exploitation and development of our shale resource plays, while continuing to evaluate complementary acquisitions that meet our strategic and financial objectives. We plan to 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, managing our liquidity and enhancing financial flexibility. We believe this will allow us to create long-term value for our shareholders.

Like all oil and natural gas exploration and production companies, we face the challenge of natural production declines. We attempt to offset the impact of this natural decline by implementing drilling and exploitation projects to identify and develop additional reserves and adding reserves through complementary acquisitions.

Recent developments

EXCO/HGI Partnership

On February 14, 2013, we formed the EXCO/HGI 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 net proceeds of $574.8 million, after final purchase price adjustments, and a 25.5% economic interest in the EXCO/HGI Partnership. HGI's economic interest in the EXCO/HGI Partnership is 74.5%. The primary strategy of the EXCO/HGI Partnership is to exploit its current asset base and acquire conventional producing oil and natural gas properties to enhance asset value and cash flow. Proceeds from the formation of the EXCO/HGI Partnership were used to reduce our outstanding indebtedness under the EXCO Resources Credit Agreement.

Immediately following the closing, the EXCO/HGI Partnership entered into an agreement to purchase the remaining shallow Cotton Valley assets within our joint venture with an affiliate of BG Group for $130.7 million, after final purchase price adjustments. The assets acquired as a result of this transaction represented an incremental working interest in properties owned by the EXCO/HGI Partnership. The transaction closed on March 5, 2013 and was funded with borrowings from the EXCO/HGI Partnership Credit Agreement.

Haynesville and Eagle Ford Acquisitions

In July 2013, we closed the acquisition of oil and natural gas assets in the Haynesville and Eagle Ford shale formations from Chesapeake for an aggregate purchase price of $942.9 million, after final purchase price adjustments ("Chesapeake Properties").

We amended and restated the EXCO Resources Credit Agreement to facilitate these acquisitions, which increased the borrowing base to $1.6 billion, including a $1.3 billion revolving commitment and a $300.0 million term loan. The credit agreement included an asset sale requirement of $400.0 million, which was reduced to $28.9 million as of December 31, 2013 using proceeds from asset sales. The asset sale requirement was eliminated as a result of the repayment of outstanding borrowings in January 2014. The repayments of indebtedness under asset sale requirement resulted in a corresponding reduction in our borrowing base. See further discussion of the EXCO Resources Credit Agreement within "Note 6. Debt" in the Notes to our Consolidated Financial Statements.

We closed the acquisition of the Haynesville assets on July 12, 2013 for a purchase price of $281.1 million, after final purchase price adjustments. The acquisition was funded with borrowings from the EXCO Resources Credit Agreement. The acquisition included certain producing wells and non-producing oil, natural gas and mineral leases located in our core Haynesville shale operating area in Caddo Parish and DeSoto Parish, Louisiana. These properties included Chesapeake's non-operated interests in 170 wells operated by EXCO on approximately 5,500 net acres, and operated interests in 11 producing wells on approximately 4,000 net acres. The acquisition added approximately 55 identified drilling locations in the Haynesville shale formation to our drilling inventory. BG Group elected not to exercise its preferential right to acquire a 50% interest in these assets.

We closed the acquisition of the Eagle Ford assets on July 31, 2013 for a purchase price of $661.8 million, after final purchase price adjustments. The acquisition included certain producing wells and non-producing oil, natural gas and mineral leases in the Eagle Ford shale in the counties of Zavala, Dimmit and Frio in South Texas. These properties include operated interests in 120 wells on approximately 53,500 net acres. The acquisition added approximately 300 identified drilling locations to our drilling inventory. In connection with the acquisition of the Eagle Ford assets, we entered into a farm-out agreement with Chesapeake covering acreage adjacent to the acquired properties. Pursuant to the terms of the farm-out agreement, Chesapeake retains an overriding royalty interest in wells drilled on acreage covered by the farm-out agreement, with an option to convert the overriding royalty interest to a working interest at payout of the well.

In connection with closing the acquisition of the Eagle Ford assets, we entered into a participation agreement with KKR, and sold an undivided 50% interest in the undeveloped acreage we acquired for approximately $130.9 million, after final purchase price adjustments. Proceeds from the sale of properties under the KKR Participation Agreement were used to reduce outstanding borrowings under the asset sale requirement of the EXCO Resources Credit Agreement, which also resulted in a corresponding reduction in our borrowing base.

The KKR Participation Agreement provides that EXCO and KKR will jointly fund future costs to develop the Eagle Ford assets. With respect to each well drilled, EXCO will assign half of its undivided 50% interest in such well to KKR such that KKR will fund and own 75% of each well drilled and EXCO will fund and own 25% of each well drilled. On a quarterly basis, EXCO and KKR will determine the development plan covering the following 12 months. EXCO will be required to offer to purchase KKR's 75% working interest in wells drilled that have been on production for one year. These offers will be made on a quarterly basis for groups of wells at a price defined in the KKR Participation Agreement, subject to specific well criteria and return hurdles. We are required to make our first offer during the first quarter of 2015 for wells that have been on-line for approximately one year. The parties have agreed on a minimum of 240 identified locations to be drilled over a five year period.

TGGT Transaction

On November 15, 2013, EXCO and BG Group closed the conveyance of 100% of the equity interests in TGGT to Azure for an aggregate sales price of approximately $910.0 million, subject to customary purchase price adjustments. The consideration consisted of approximately $876.5 million in cash and an equity interest in Azure which was split equally between EXCO and BG Group. The equity interest issued to EXCO was approximately 4% of the total outstanding equity interests of Azure as of the closing date. EXCO and BG Group were granted an option for a period of one year to acquire an additional equity interest in Azure equal to the equity interest issued at closing for approximately $16.8 million plus a premium that will increase over time. We received $240.2 million in net cash proceeds at the closing of the transaction.

At the closing of the agreement, EXCO and BG Group agreed to deliver to Azure’s gathering systems an aggregate minimum volume commitment of 600,000 Mmbtu per day of natural gas production from the Holly and Shelby fields over a five year period. The minimum volume commitment may be satisfied with (i) production of EXCO, BG Group and each of their respective affiliates, (ii) production of joint venture partners of either EXCO, BG Group or their affiliates, and (iii) production of non-operating working interest owners to the extent EXCO, BG Group, and each of their respective affiliates or its joint venture partner controls such production. If there is a shortfall to the minimum volume commitment in any year, then EXCO and BG Group are severally responsible for paying to Azure a shortfall payment in an amount equal to the amount of the shortfall (calculated on an annualized basis) times $0.40 per Mmbtu. EXCO and BG Group are entitled to credit 25% of any production volumes delivered in excess of the minimum volume commitment during any year to the subsequent year.

We utilized the cash proceeds from the sale of TGGT to reduce outstanding borrowings under the asset sale requirement of the EXCO Resources Credit Agreement, which also resulted in a corresponding reduction in our borrowing base. There was $28.9 million outstanding under the asset sale requirement after the repayment of indebtedness using proceeds from the TGGT transaction. We recorded an other than temporary impairment of $86.8 million to our investment in TGGT during the year ended December 31, 2013 as a result of the carrying value exceeding the fair value.

Management Change

Douglas H. Miller resigned from serving as our chief executive officer, chairman of the board of directors and as a director on November 20, 2013. Our board of directors appointed Jeffrey D. Benjamin to serve as non-executive chairman of the board of directors and initiated a search to identify a new chief executive officer.

Rights Offering

On December 19, 2013, the Company granted subscription rights to holders of common stock which entitled the holder to purchase 0.25 of a share of our common stock for each share of common stock owned by such holders ("Rights Offering"). Each subscription right entitled the holder to a basic subscription right and an over-subscription privilege. The basic subscription right entitled the holder to purchase 0.25 of a share of the Company’s common stock at a subscription price equal to $5.00 per share of common stock. The over-subscription privilege entitled the holders who exercised their basic subscription rights in full (including in respect of subscription rights purchased from others) to purchase any or all shares of common stock that other rights holders did not purchase through the purchase of their basic subscription rights at a subscription price equal to $5.00 per share of common stock. The subscription rights expired if they were not exercised by January 9, 2014.

The Company entered into two investment agreements ("Investment Agreements") in connection with the Rights Offering, each dated as of December 17, 2013, one with certain affiliates of WL Ross and one with Hamblin Watsa pursuant to which, subject to the terms and conditions thereof, each of them severally agreed to subscribe for and purchase, in a private placement, its respective pro rata portion of shares under the basic subscription right and all unsubscribed shares under the over-subscription privilege subject to the pro rata allocation among the subscription rights holders who have elected to exercise their over-subscription privilege.

The Rights Offering and related transactions under the Investment Agreements closed on January 17, 2014 which resulted in the issuance of 54,574,734 shares for proceeds of $272.9 million. WL Ross and Hamblin Watsa purchased 19,599,973 and 6,726,712 shares, respectively, pursuant to their basic subscription rights and the over-subscription privilege. After giving effect to the Rights Offering, WL Ross and Hamblin Watsa owned 18.7% and 6.4%, respectively of the Company's outstanding common shares as of January 17, 2014. We used the proceeds to pay the remaining indebtedness related to the asset sale requirement as well as a portion of the indebtedness outstanding under the revolving commitment under the EXCO Resources Credit Agreement. Upon repayment of the asset sale requirement, the interest rate on the revolving commitment decreased by 100 basis points. After giving effect to the Rights Offering and the related transactions under the Investment Agreements, the available borrowing base on the revolving commitment under the EXCO Resources Credit Agreement was $900.0 million with approximately $491.0 million of outstanding indebtedness and approximately $402.1 million of unused borrowing base, net of letters of credit.

Critical accounting policies

In response to the SEC 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 estimates of Proved Reserves, accounting for derivatives, business combinations, share-based compensation, oil and natural gas properties, goodwill, revenue recognition, asset retirement obligations and income taxes.

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

Estimates of Proved Reserves

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

- the quality and quantity of available data;
- the interpretation of 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 shale properties 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. 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 ("*ASC 805-10") to record our acquisitions of oil and natural gas properties or entities. 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.

Derivative financial instruments

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 compensation

We account for share-based compensation in accordance with ASC 718 which requires share-based compensation to employees 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 share-based compensation. EXCO uses the full cost method to account for its oil and natural gas properties. As a result, we capitalize part of our share-based compensation that is attributable to our acquisition, exploration, exploitation and development activities. Total share-based compensation for the year ended December 31, 2013 was $18.0 million, of which $7.3 million was capitalized as part of our oil and natural gas properties. For the years ended December 31, 2012 and 2011, a total of $16.4 million and $17.4 million, respectively, of share-based compensation was incurred, of which $7.5 million and $6.4 million, respectively, was capitalized.

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 $425.3 million and $470.0 million as of December 31, 2013 and 2012, 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 or determination that no proved reserves are attributable to such costs. Our undeveloped properties are predominantly held-by-production, which reduces the risk of impairment as a result of lease expirations. 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. As a result of this evaluation, we impaired approximately $1.0 million and $60.8 million of undeveloped properties during 2013 and 2012, respectively, which were transferred to the depletable portion of the full cost pool during each year. The impairment was recorded 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.

We capitalize interest on the costs related to the acquisition of undeveloped acreage 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 related to these properties.

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 acquisition, 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 ("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 impairment 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 12 month period using the first day of each month. For the 12 months ended December 31, 2013, the trailing 12 month reference prices were $3.67 per Mmbtu for natural gas at Henry Hub and $96.78 per Bbl of oil for West Texas Intermediate ("WTI") at Cushing, Oklahoma. The price used for NGL's was $39.92 per Bbl and was based on average realized prices in 2013. 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 impairments of oil and natural gas properties may not be reversed in subsequent periods. Since we do not designate our derivative financial instruments as hedging instruments, we are not allowed to use the impacts of the derivative financial instruments in our ceiling test computations.

As of December 31, 2013 pursuant to Rule 4-10(c)(4) of Regulation S-X, we were required to compute the ceiling test using the simple average spot price for the trailing 12 month period for oil and natural gas. The computation resulted in the carrying costs of our unamortized proved oil and natural gas properties, exceeding the December 31, 2013 ceiling test limitation by approximately $156.6 million, including the recently acquired Chesapeake Properties. Our pricing for the acquisitions of the Chesapeake Properties was based on models which incorporate, among other things, market prices based on NYMEX futures as of the acquisition date. The ceiling test requires companies using the full cost accounting method to price period ending proved reserves using the simple average spot price for the trailing 12 month period, which may not be indicative of actual market values. Given the short passage of time between closing of these acquisitions and the required ceiling test computation, the Company requested, and received, an exemption from the SEC to exclude the acquisition of the Chesapeake Properties from the ceiling test assessments for a period of 12 months following the corresponding acquisition dates.

If we cannot demonstrate the fair value of the Chesapeake Properties exceeds the unamortized carrying costs during the requested exemption periods prior to issuance of our financial statements, we are required to recognize an impairment. We evaluated the Chesapeake Properties for impairment using discounted cash flow models based on internally generated oil and natural gas reserves as of December 31, 2013. The Company's expectation of future prices is principally based on NYMEX futures contracts, adjusted for basis differentials. We believe the NYMEX futures contract reflects an independent pricing point for determining fair value.

The evaluation of impairment of our oil and natural gas properties includes 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.

For the years ended December 31, 2013, 2012, and 2011 we recognized impairments of $108.5 million, $1.3 billion, and $233.2 million, respectively, to our proved oil and natural gas properties.

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

We apply a two-part, equally weighted approach in determining the fair value of our business as part of the goodwill impairment test. 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 our business exceeded the carrying value of net assets and we did not record an impairment charge for the periods ended December 31, 2013, 2012 and 2011.

The contribution of oil and natural gas properties to the EXCO/HGI Partnership resulted in a significant alteration in our depletion rate. In accordance with full cost accounting rules, we recorded a gain of $186.4 million, net of a proportionate reduction in goodwill of $55.1 million, for the year ended December 31, 2013. The balance of goodwill as of December 31, 2013 and 2012 was $163.2 million and $218.3 million, respectively.

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, 2013, 2012 and 2011 were not significant.

Asset retirement obligations

We follow FASB ASC 410-20, *Asset Retirement Obligations ("*ASC 410-20") 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.

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, 2013, 2012 and 2011 related to our results of operations is presented below:

	Year Ended December 31,			Year to year change	
(dollars in thousands, except per unit prices)	2013	2012	2011	2013-2012	2012-2011
Production:					
Oil (Mbbls)	1,188	704	741	484	(37)
Natural gas liquids (Mbbls)	243	510	505	(267)	5
Natural gas (Mmcf)	153,321	182,644	176,700	(29,323)	5,944
Total production (Mmcfe) (1)	161,907	189,928	184,176	(28,021)	5,752
Average daily production (Mmcfe)	444	519	505	(75)	14
Revenues before derivative financial instrument activities:					
Oil	$ 111,440	$ 62,119	$ 67,440	$ 49,321	$ (5,321)
Natural gas liquids	8,560	22,068	29,639	(13,508)	(7,571)
Natural gas	514,309	462,422	657,122	51,887	(194,700)
Total revenues	$ 634,309	$ 546,609	$ 754,201	$ 87,700	$ (207,592)
Oil and natural gas derivative financial instruments:					
Gain (loss) on derivative financial instruments	$ (320)	$ 66,133	$ 219,730	$ (66,453)	$ (153,597)
Average sales price (before cash settlements of derivative financial instruments):					
Oil (per Bbl)	$ 93.80	$ 88.24	$ 91.01	$ 5.56	$ (2.77)
Natural gas liquids (per Bbl)	35.23	43.27	58.69	(8.04)	(15.42)
Natural gas (per Mcf)	3.35	2.53	3.72	0.82	(1.19)
Natural gas equivalent (per Mcfe)	3.92	2.88	4.10	1.04	(1.22)
Costs and expenses:					
Oil and natural gas operating costs	$ 61,277	$ 77,127	$ 84,766	$ (15,850)	$ (7,639)
Production and ad valorem taxes	21,971	27,483	23,875	(5,512)	3,608
Gathering and transportation	100,645	102,875	86,881	(2,230)	15,994
Depletion	237,899	288,401	344,947	(50,502)	(56,546)
Depreciation and amortization	7,876	14,755	18,009	(6,879)	(3,254)
General and administrative (2)	91,878	83,818	104,618	8,060	(20,800)
Interest expense, net	102,589	73,492	61,023	29,097	12,469
Costs and expenses (per Mcfe):					
Oil and natural gas operating costs	$ 0.38	$ 0.41	$ 0.46	$ (0.03)	$ (0.05)
Production and ad valorem taxes	0.14	0.14	0.13	—	0.01
Gathering and transportation	0.62	0.54	0.47	0.08	0.07
Depletion	1.47	1.52	1.87	(0.05)	(0.35)
Depreciation and amortization	0.05	0.08	0.10	(0.03)	(0.02)
General and administrative	0.57	0.44	0.57	0.13	(0.13)
Net income (loss)	$ 22,204	$ (1,393,285)	$ 22,596	$ 1,415,489	$ (1,415,881)

(1) Mmcfe is calculated by converting one barrel of oil or NGLs into six Mcf of natural gas.
(2) Share-based compensation expense included in general and administrative expenses was $10.7 million, $8.9 million and $10.9 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The following is a discussion of our financial condition and results of operations for the years ended December 31, 2013, 2012 and 2011.

The comparability of our results of operations for 2013, 2012 and 2011 was affected by:

- the acquisitions of the Haynesville and Eagle Ford assets from Chesapeake during 2013, including the debt refinancing to facilitate these acquisitions;
- the formation of the EXCO/HGI Partnership during 2013;
- the sale of our equity interest in TGGT during 2013;
- fluctuations in oil, natural gas and NGLs prices, which impact our oil and natural gas reserves, revenues, cash flows and net income or loss;
- impairments of our oil and natural gas properties in 2013, 2012 and 2011;
- the Chief transaction, the Appalachia transaction and the Haynesville shale acquisition in 2011;
- asset impairments and other non-recurring costs;
- 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 declining natural gas production volumes from our reduced horizontal drilling activities in certain shale formations; and
- significant changes in the amount of our debt.

General

The availability of a ready market and the prices for 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, natural gas and natural gas liquids. We do not refine or process the oil, natural gas or natural gas liquids 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 natural gas liquids 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, 2013, 2012 and 2011, we reported net income of $22.2 million, a net loss of $1.4 billion and net income of $22.6 million, respectively. The net income for the year ended December 31, 2013 was primarily the result of income from operations and the gain on the divestiture of certain oil and natural gas properties and related assets in connection with the formation of the EXCO/HGI Partnership. This was partially offset by the impairments of our oil and natural gas properties and our investment in TGGT. The net loss for 2012 was primarily the result of impairments of our oil and natural gas properties as well as lower revenues, both of which were the result of significant declines in natural gas prices in 2012. The net income for 2011 was the result of increased revenues due to higher natural gas prices and gains on derivative financial instruments, which were partially offset by impairments of our oil and natural gas properties.

Average natural gas equivalent prices for the year ended December 31, 2013 were $3.92 per Mcfe, compared with an average natural gas equivalent price of $2.88 per Mcfe for 2012 and $4.10 per Mcfe for 2011.

We use oil and natural gas swap, basis swap and call option contracts to manage our exposure to commodity price fluctuations, protect our returns on investments and achieve a more predictable cash flow from our operations. The realized and unrealized changes in the fair value of derivative financial instruments resulted in net losses of $0.3 million for the year ended December 31, 2013 and net gains of $66.1 million and $219.7 million for the years ended December 31, 2012, and 2011, respectively.

Presentation of results of operations

Our discussion of production, revenues and direct operating expenses is based on our producing regions and the EXCO/HGI Partnership. The EXCO/HGI Partnership includes conventional non-shale assets in East Texas, North Louisiana and the Permian Basin. Prior to the formation of the EXCO/HGI Partnership on February 14, 2013, the operating results of the properties contributed by EXCO were included within the "East Texas/North Louisiana" and "Permian and other" regions within our discussion of production, revenues and direct operating expenses. The operating results of the EXCO/HGI Partnership represent our proportionate interest subsequent to its formation on February 14, 2013.

We closed the acquisition of Haynesville and Eagle Ford assets from Chesapeake on July 12, 2013 and July 31, 2013, respectively. Our results of operations reflect these assets subsequent to the closing dates of the respective acquisitions. The Haynesville assets are included within our "East Texas/North Louisiana" region, and the Eagle Ford assets are included within our "South Texas" region.

Oil and natural gas production, revenues and prices

We are presenting information on a pro forma basis to provide a more meaningful analysis of our on-going production activity as a result of the formation of the EXCO/HGI Partnership and our recent acquisitions of the Chesapeake Properties. These pro forma adjustments reflect the contribution of properties by EXCO in connection with the formation of the EXCO/HGI Partnership, the EXCO/HGI Partnership's acquisition of shallow Cotton Valley assets from an affiliate of BG Group, and the acquisition of the Chesapeake Properties. The pro forma adjustments reflect our production as if the aforementioned transactions had occurred on January 1, 2011.

(in Mmcfe)	Year Ended December 31, 2013 Production	 EXCO/HGI pro forma adjustments	 Chesapeake Properties pro forma adjustments	 Pro forma production
Producing region:				
East Texas/North Louisiana	123,218	(3,094)	20,031	140,155
South Texas	6,197	—	7,248	13,445
Appalachia	22,816	—	—	22,816
Permian and other	1,139	(972)	—	167
EXCO/HGI Partnership	8,537	1,361	—	9,898
Total	161,907	(2,705)	27,279	186,481

(in Mmcfe)	Year Ended December 31, 2012 Production	 EXCO/HGI pro forma adjustments	 Chesapeake Properties pro forma adjustments	 Pro forma production
Producing region:				
East Texas/North Louisiana	164,779	(27,811)	38,004	174,972
South Texas	—	—	8,410	8,410
Appalachia	16,153	—	—	16,153
Permian and other	8,996	(8,830)	—	166
EXCO/HGI Partnership	—	11,564	—	11,564
Total	189,928	(25,077)	46,414	211,265

(in Mmcfe)	Year Ended December 31, 2011 Production	 EXCO/HGI pro forma adjustments	 Chesapeake Properties pro forma adjustments	 Pro forma production
Producing region:				
East Texas/North Louisiana	162,693	(31,485)	26,053	157,261
South Texas	—	—	2,107	2,107
Appalachia	12,408	—	—	12,408
Permian and other	9,075	(5,562)	—	3,513
EXCO/HGI Partnership	—	17,767	—	17,767
Total	184,176	(19,280)	28,160	193,056

The following table presents our production, revenue and average sales prices for the years ended December 31, 2013 and 2012:

	Year Ended December 31,								
	2013			2012			Year to year change		
(dollars in thousands, except per unit rate)	Production (Mmcfe)	Revenue	$/Mcfe	Production (Mmcfe)	Revenue	$/Mcfe	Production (Mmcfe)	Revenue	$/Mcfe
Producing region:									
East Texas/North Louisiana	123,218	$ 417,811	$ 3.39	164,779	$ 420,579	$ 2.55	(41,561)	$ (2,768)	$ 0.84
South Texas	6,197	85,926	13.87	—	—	—	6,197	85,926	13.87
Appalachia	22,816	78,424	3.44	16,153	47,379	2.93	6,663	31,045	0.51
Permian and other	1,139	9,135	8.02	8,996	78,651	8.74	(7,857)	(69,516)	(0.72)
EXCO/HGI Partnership	8,537	43,013	5.04	—	—	—	8,537	43,013	5.04
Total	161,907	$ 634,309	$ 3.92	189,928	$ 546,609	$ 2.88	(28,021)	$ 87,700	$ 1.04

Production in our East Texas/North Louisiana region for the year ended December 31, 2013 decreased by 41.6 Bcfe from 2012. The decrease in production was primarily due to the impact of the contribution of properties to the EXCO/HGI Partnership of 24.7 Bcfe, as well as normal production declines and a reduced drilling program. The decrease was partially offset by additional production from the Haynesville assets acquired from Chesapeake. During the year ended December 31, 2013, we operated an average of three horizontal rigs in the East Texas/North Louisiana region, as compared to an average of eight rigs during the year ended December 31, 2012. Additionally, there was a large inventory of wells that were waiting on completion at the end of 2011 that were completed and turned-to-sales during the 2012 fiscal year. This resulted in 84 wells turned-to-sales during 2012 compared to 51 wells turned-to-sales during 2013. We acquired assets in South Texas region focused on the Eagle Ford shale on July 31, 2013. Our production in the South Texas region was 6.2 Bcfe from the acquisition date to December 31, 2013, which consisted of 941 Mbbls of oil, 28 Mbbls of natural gas liquids and 379 Mmcf of natural gas. The increase in production of 6.7 Bcfe in the Appalachia region was a result of our completion activities in the Marcellus shale. During 2013, we turned-to-sales 20 wells in the Marcellus shale which primarily consisted of wells in our inventory waiting upon completion as of the end of 2012. The decrease in production in the Permian and other region was primarily the result of the contribution of properties to the EXCO/HGI Partnership. Our proportionate share of the EXCO/HGI Partnership's production consisted of 6.7 Bcfe from East Texas/North Louisiana and 1.8 Bcfe from the Permian Basin.

For the years ended December 31, 2013 and 2012, oil and natural gas revenues were $634.3 million and $546.6 million, respectively. The increase in revenues was primarily the result of an increase in oil and natural gas prices and the acquisition of the Chesapeake Properties, which was partially offset by lower revenues arising from the contribution of properties to the EXCO/HGI Partnership and normal production declines. Our average natural gas sales price increased 32.4% to $3.35 per Mcf for the year ended December 31, 2013 from $2.53 per Mcf for the year ended December 31, 2012. Our average sales price for natural gas during 2013 was negatively impacted by the widening of differentials in Appalachia as a result of an oversupply in the Northeast region. Also, our average sales price for natural gas in 2013 was negatively impacted by lower prices received from our purchasers for natural gas production in the South Texas region due to higher deductions for gathering and transportation costs. Our average sales price of oil per Bbl increased 6.3% to $93.80 per Bbl for the year ended December 31, 2013 from $88.24 per Bbl for the year ended December 31, 2012. Our average sales price for oil in the South Texas region is most closely correlated to the Louisiana Light Sweet ("LLS") price index. LLS prices have historically traded at a premium to WTI, however this differential narrowed during 2013. Our average sales price of natural gas liquids per Bbl decreased 18.6% to $35.23 per Bbl for the year ended December 31, 2013 from $43.27 per Bbl for the year ended December 31, 2012.

Our production volumes in shale operations are impacted by curtailed volumes of oil and natural gas due to operational requirements associated with drilling, 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.

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

	Year Ended December 31,								
	2012			2011			Year to year change		
(dollars in thousands, except per unit rate)	Production (Mmcfe)	Revenue	$/Mcfe	Production (Mmcfe)	Revenue	$/Mcfe	Production (Mmcfe)	Revenue	$/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)
South Texas	—	—	—	—	—	—	—	—	—
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)
EXCO/HGI Partnership	—	—	—	—	—	—	—	—	—
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 2011. This increase is the result of the continued development of our shale assets in this region during 2011 and 2012. This increase was partially offset by normal production declines of 4.8 Bcfe in our Vernon Field and other shallow conventional wells in the region. The increase in Appalachia area is the result of the horizontal drilling program in the Marcellus shale. Our production in the Permian Basin remained flat as a result of a continued one drilling rig program focused on conventional assets.

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 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 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. The average sales price of natural gas decreased 32.0% to $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.

The prices received for our oil and natural gas production are 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. Market conditions involving over or under supply of oil or 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, 2013 average production levels remain constant, 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 $15.3 million, a change in the average sales price of $1.00 per Bbl of NGLs would result in an increase or decrease in revenues and cash flows of approximately $0.2 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 $1.2 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, 2013 and 2012 were $61.3 million and $77.1 million, respectively. The decreases in total oil and natural gas operating expenses for 2013 as compared to 2012 were primarily due to the contribution of properties to the EXCO/HGI Partnership. Additionally, we continued to focus on cost saving initiatives throughout the organization. These decreases were offset by additional oil and natural gas operating costs as a result of the acquisition of the Chesapeake Properties.

As shown in the tables below, oil and natural gas operating costs for the year ended December 31, 2013 were $0.38 per Mcfe, a decrease of 7.3% from 2012. The net decrease in oil and natural gas operating costs per Mcfe is attributable to the contribution of properties to EXCO/HGI Partnership, which typically have a higher cost per Mcfe compared to the rest of our properties. This was partially offset by a higher cost per Mcfe associated with our oil production in the South Texas region.

	Year Ended December 31,								
	2013			2012			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	$ 16,980	$ 4,294	$ 21,274	$ 39,897	$ 9,497	$ 49,394	$(22,917)	$ (5,203)	$ (28,120)
South Texas	11,454	13	11,467	—	—	—	11,454	13	11,467
Appalachia	14,073	—	14,073	14,882	—	14,882	(809)	—	(809)
Permian and other	1,623	—	1,623	12,539	312	12,851	(10,916)	(312)	(11,228)
EXCO/HGI Partnership	11,397	1,443	12,840	—	—	—	11,397	1,443	12,840
Total	$ 55,527	$ 5,750	$ 61,277	$ 67,318	$ 9,809	$ 77,127	$(11,791)	$ (4,059)	$ (15,850)

	Year Ended December 31,								
	2013			2012			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	$ 0.14	$ 0.03	$ 0.17	$ 0.24	$ 0.06	$ 0.30	$ (0.10)	$ (0.03)	$ (0.13)
South Texas	1.85	—	1.85	—	—	—	1.85	—	1.85
Appalachia	0.62	—	0.62	0.92	—	0.92	(0.30)	—	(0.30)
Permian and other	1.42	—	1.42	1.39	0.03	1.42	0.03	(0.03)	—
EXCO/HGI Partnership	1.34	0.17	1.51	—	—	—	1.34	0.17	1.51
Total	$ 0.34	$ 0.04	$ 0.38	$ 0.36	$ 0.05	$ 0.41	$ (0.02)	$ (0.01)	$ (0.03)

Our oil and natural gas operating costs for the year ended December 31, 2012 and 2011 were $77.1 million and $84.8 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. Examples of these actions include shutting in marginal producing wells with high-cost water production, decreased compression expenditures and modification of our chemical treating programs.

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 decreases in both our East Texas/North Louisiana and Appalachia regions were primarily due to the combination of increased production in 2012 and implementation of numerous cost savings initiatives. The Permian Basin operating expenses per Mcfe increased due to higher field maintenance and general service costs associated with oil and NGL production in 2012.

(in thousands)	Year Ended December 31, 2012 Lease operating expenses	Workovers and other	Total	2011 Lease operating expenses	Workovers and other	Total	Year to year change 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)
South Texas	—	—	—	—	—	—	—	—	—
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
EXCO/HGI Partnership	—	—	—	—	—	—	—	—	—
Total	$ 67,318	$ 9,809	$ 77,127	$ 74,139	$ 10,627	$ 84,766	$ (6,821)	$ (818)	$ (7,639)

(per Mcfe)	Year Ended December 31, 2012 Lease operating expenses	Workovers and other	Total	2011 Lease operating expenses	Workovers and other	Total	Year to year change 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)
South Texas	—	—	—	—	—	—	—	—	—
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
EXCO/HGI Partnership	—	—	—	—	—	—	—	—	—
Total	$ 0.36	$ 0.05	$ 0.41	$ 0.40	$ 0.06	$ 0.46	$ (0.04)	$ (0.01)	$ (0.05)

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 contain revenues which are reported under two separate bases. Gathering and transportation expenses totaled $100.6 million, or $0.62 per Mcfe, for the year ended December 31, 2013, as compared to $102.9 million, or $0.54 per Mcfe for the year ended December 31, 2012 and $86.9 million, or $0.47 per Mcfe for the year ended December 31, 2011. The increases in gathering and transportation expense on a per Mcfe basis from 2011 to 2013 were primarily due to higher costs associated with unused firm transportation volumes.

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 2013, our firm transportation agreements covered an average of 1.1 Bcf per day through 2016, with average minimum gathering and transportation expenses of approximately $135.3 million per year. For the years 2017 through 2021, our firm transportation agreements range from covering an average of 1.0 Bcf per day in 2017 and trend down to 333 Mmcf per day in 2021, with average annual minimum gathering and transportation expenses ranging from approximately $132.9 million per year in 2017 and trending down to $40.7 million in 2021. These volumes and expenses represent our gross commitments under these contracts and a portion of these costs will be incurred by all working interest owners.

Production and ad valorem taxes

	Year Ended December 31,								
	2013			2012			2011		
(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	$ 9,287	2.2%	$ 0.08	$ 17,501	4.2%	$ 0.11	$ 14,851	2.4%	$ 0.09
South Texas	4,962	5.8%	0.80	—	—%	—	—	—%	—
Appalachia	2,653	3.4%	0.12	3,013	6.4%	0.19	1,694	3.2%	0.14
Permian and other	815	8.9%	0.72	6,969	8.9%	0.77	7,330	7.8%	0.81
EXCO/HGI Partnership	4,254	9.9%	0.50	—	—%	—	—	—%	—
Total	$ 21,971	3.5%	$ 0.14	$ 27,483	5.0%	$ 0.14	$ 23,875	3.2%	$ 0.13

Production and ad valorem taxes were $22.0 million, $27.5 million and $23.9 million for the years ended 2013, 2012, and 2011, respectively. The decrease for the year ended December 31, 2013 compared to 2012 was primarily attributable to lower production volumes due to the contribution of properties to the EXCO/HGI Partnership and the decrease in the State of Louisiana severance tax rate to $0.118 per Mcf in July 2013 for wells that did not have a severance tax holiday. These decreases were partially offset by higher production and ad valorem taxes associated with our liquids production in the South Texas region. The increase for the year ended December 31, 2012 compared to 2011 was primarily attributable to higher production volumes, higher ad valorem taxes based on our continued development in the Haynesville shale, and the enactment of the Pennsylvania impact fee. This increase was partially offset by the decrease in the State of Louisiana severance tax rate from $0.164 to $0.148 per Mcf in July 2012 for wells that did not have a severance tax holiday.

Production and ad valorem tax rates per Mcfe were $0.14, $0.14 and $0.13 for 2013, 2012 and 2011, respectively. The rate per Mcfe stayed consistent on a consolidated basis for the year ended December 31, 2013 compared 2012, however there were offsetting fluctuations amongst our producing regions. The rate per Mcfe in the East Texas/North Louisiana region decreased from 2012 primarily due to the contribution of properties to the EXCO/HGI Partnership, which typically have a higher rate per Mcfe compared to our shale properties in the region since these assets do not currently receive severance tax holidays. The rate per Mcfe in the Appalachia region decreased due to higher production in relation to the number of wells spud during the year that would be subject to the Pennsylvania impact fee. This decrease was offset by higher production and ad valorem taxes per Mcfe associated with our liquids production in the South Texas region. The rate per Mcfe increased by $0.01 on a consolidated basis for the year ended December 31, 2012 compared to 2011. The increase was primarily due to the enactment of the Pennsylvania impact fee during 2012 and higher ad valorem taxes as a result of our development in the Haynesville shale.

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. Our horizontal wells in the state of Louisiana are eligible for an exemption from severance taxes for the earlier of two years from the date of first production or until payout of qualified costs. In July 2013, the state of Louisiana decreased its severance tax rate to $0.118 per Mcf. During the period from July 1, 2012 to June 30, 2013, wells that did not have a severance tax holiday were charged a severance tax rate of $0.148 per Mcf. Prior to the adjustment of the severance tax rate in July 2012, wells that did not have a severance tax holiday were charged a severance tax rate of $0.164 per Mcf.

In February 2012, the Commonwealth of Pennsylvania enacted a comprehensive reform to Pennsylvania's Oil and Gas Act ("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 was 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. For the years ended December 31, 2013 and 2012, we recorded $1.6 million and $1.8 million as our estimated impact fees, respectively.

Production and ad valorem taxes are set by state and local governments and vary as to the tax rate and the value to which that rate is applied. 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.

Depletion, depreciation and amortization

The depletion, depreciation and amortization rate per Mcfe produced varies significantly for each of the periods presented due to acquisitions, divestitures and impairments of our oil and natural gas properties. The depletion rate for the year ended December 31, 2013 was $1.47 per Mcfe, a $0.05 decrease from the year ended December 31, 2012. The decrease is primarily the result of significant impairments of our oil and natural gas properties during 2012, which lowered our depletable base. This was partially offset by an increase in our depletable base from the acquisition of the Chesapeake Properties and higher future development costs due to an increase in proved undeveloped reserves resulting from higher natural gas prices. The depletion rate for the year ended December 31, 2012 was $1.52 per Mcfe, a $0.35 decrease from the year ended December 31, 2011. The decrease is primarily the result of impairments of our oil and natural gas properties, which lowered our depletable base. We expect this rate to increase during 2014 as a result of a higher depletion rate associated with our oil producing assets in the South Texas region and the downward revisions of reserve quantities to our properties in the Haynesville shale during the fourth quarter of 2013.

Our depreciation and amortization costs for the year ended December 31, 2013 decreased by $6.9 million, or 46.6%, compared to the same period in 2012. The decrease was due to contribution of gathering assets to the EXCO/HGI Partnership and the sale of other corporate assets in the prior year. Our depreciation and amortization costs for the year ended December 31, 2012 decreased by $3.3 million, or 18.1%, from 2011. The decrease was primarily due to the sale of other corporate assets during 2012.

Accretion of discount on asset retirement obligations was $2.5 million, $3.9 million and $3.7 million for the years ended December 31, 2013, 2012 and 2011, respectively. The decrease for the year ended December 31, 2013 compared to prior years was the result of the contribution of properties to the EXCO/HGI Partnership.

Impairment of oil and natural gas properties

For the years ended December 31, 2013, 2012, and 2011, we recorded impairments of our oil and natural gas properties of $108.5 million, $1.3 billion and $233.2 million, respectively. The impairments for the year ended December 31, 2013 were primarily due to continued low natural gas prices for the trailing 12 months at the end of the first quarter of 2013, downward revisions to the reserves of our Haynesville shale properties based on operational matters, narrowing of basis differentials between oil price indices, and higher costs associated with the gathering and transportation of our natural gas production from the Eagle Ford shale. The impairments of our oil and natural gas properties during 2012 and 2011 were due to the significant decline in natural gas prices.

General and administrative

The following table presents our general and administrative expenses for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,			Year to year change	
(in thousands, except per unit rate)	**2013**	**2012**	**2011**	**2013-2012**	**2012-2011**
General and administrative costs:					
Gross general and administrative expense	$ 147,432	$ 152,057	$ 175,030	$ (4,625)	$ (22,973)
Technical services and service agreement charges	(26,846)	(25,242)	(29,061)	(1,604)	3,819
Operator overhead reimbursements	(10,462)	(20,544)	(18,407)	10,082	(2,137)
Capitalized salaries and share-based compensation	(18,246)	(22,453)	(22,944)	4,207	491
General and administrative expense	$ 91,878	$ 83,818	$ 104,618	$ 8,060	$ (20,800)
General and administrative expense per Mcfe	$ 0.57	$ 0.44	$ 0.57	$ 0.13	$ (0.13)

Significant components of the changes in general and administrative expense for the year ended December 31, 2013 compared to 2012 were a result of:

- decreased personnel expenses of $11.0 million primarily related to a reduction in employee headcount. This decrease was partially offset by $5.0 million of severance costs associated with the resignation of our former Chairman and Chief Executive Officer. The decrease also included a reduction in contract labor costs as part of cost-cutting initiatives throughout the Company;
- increased technical service and service agreement recoveries of $1.6 million primarily due to service agreement charges associated with the operations of the EXCO/HGI Partnership, which was partially offset by decreased employee costs;
- decreased overhead recoveries of $10.1 million arising from reductions in our drilling program and the contribution of properties to the EXCO/HGI Partnership;
- decreased capitalized salaries and share-based compensation of $4.2 million primarily as a result of a reduction in employee headcount;
- increased share-based compensation expense of $1.6 million primarily associated with the modification of share-based payments in connection with the retirement of our former President and Chief Financial Officer, as well as the resignation of our former Chairman and Chief Executive Officer. This was partially offset by a reduction in employee headcount from prior year; and
- increased various other expenses of $4.8 million primarily consisting of employee relocation costs associated with the centralization of certain functions from the Appalachia region, transition service costs associated with the acquisition of the Chesapeake Properties, as well as higher engineering and technology costs.

Significant components of the changes in general and administrative expense for the year ended December 31, 2012 compared to 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 employee headcount and decrease in the number of options granted in 2012;
- decreased travel costs of $1.9 million as part of our cost reduction efforts;
- 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;
- increased operated overhead recoveries of $2.1 million arising from additional wells drilled in 2012 and 2011;
- higher legal expenses of $0.6 million and $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.

(Gain) loss on divestitures and other operating items

Our (gain) loss on divestitures and other operating items for the year ended December 31, 2013 was a net gain of $177.5 million, compared with net losses of $17.0 million and $23.8 million for the years ended December 31, 2012 and 2011, respectively. The net gain for the year ended December 31, 2013 was primarily related to the gain of $186.4 million as a result of the contribution of certain oil and natural gas properties to the EXCO/HGI Partnership. Partially offsetting the gain were $3.0 million of transaction costs associated with the acquisition of Haynesville and Eagle Ford assets, $6.7 million of expenses related to various lawsuits including the underpayment of royalties and the allocation of post-production costs, and various other transactions. The net loss of $17.0 million for the year ended December 31, 2012 included 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 impairments. 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 comparisons between periods. The net loss of $23.8 million for 2011 included expenses related to various lawsuits, the impairment of treating facilities in our Vernon Field, impairments of inventory items and costs associated with the former acquisition proposal that was terminated in July 2011.

Interest expense, net

Our interest expense, net for the year ended December 31, 2013 increased $29.1 million from the year ended December 31, 2012. The increase was primarily due to the acceleration of deferred financing costs associated with the EXCO Resources Credit Agreement. We incurred $21.0 million in accelerated deferred financing costs during 2013 primarily as a result of the amendments to the EXCO Resources Credit Agreement and the reduction in our borrowing base from the repayment of outstanding borrowings with the proceeds from the contribution of properties to the EXCO/HGI Partnership, sale of assets to KKR, and sale of our equity interest in TGGT. The increase in interest expense, net was also the result of a reduction in capitalized interest related to lower balance of unproved oil and natural gas properties. The increase in our average interest rate under the EXCO Resources Credit Agreement as a result of the asset sale requirement and the term loan was partially offset by lower average borrowings during 2013 compared to prior year.

Our interest expense, net for the year ended December 31, 2012 increased $12.5 million from December 31, 2011 due to higher average outstanding borrowings under the EXCO Resources Credit Agreement and decreases of capitalized interest related to the lower balances of 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 paid in 2011 in connection with the formation of the TGGT credit facility.

The following table presents our interest expense for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,			Period to period change	
(in thousands)	**2013**	**2012**	**2011**	**2013-2012**	**2012-2011**
Interest expense:					
2018 Notes	$ 57,485	$ 57,394	$ 57,309	$ 91	$ 85
Revolving credit facility under EXCO Resources Credit Agreement	26,858	31,068	23,517	(4,210)	7,551
Term Loan under EXCO Resources Credit Agreement	6,261	—	—	6,261	—
EXCO/HGI Partnership Credit Agreement	2,335	—	—	2,335	—
Amortization and write-off of deferred financing costs	28,169	8,644	8,700	19,525	(56)
Capitalized interest	(18,729)	(23,809)	(30,083)	5,080	6,274
Other	210	195	1,580	15	(1,385)
Total interest expense	$ 102,589	$ 73,492	$ 61,023	$ 29,097	$ 12,469

Cash interest payments for the years ended December 31, 2013, 2012 and 2011 were $88.9 million, $86.3 million and $78.1 million, respectively.

Derivative financial instruments

Our oil and natural gas derivative financial instruments resulted in a net loss of $0.3 million and net gains of $66.1 million and $219.7 million for the years ended December 31, 2013, 2012 and 2011, respectively. The net loss during 2013 compared to the gains during the years ended December 31, 2012 and 2011 were the result of declines in the price of natural gas in prior years. Based on the nature of our derivative contracts, decreases in the related commodity price typically result in increases to the value of our derivatives contracts. The significant fluctuations demonstrate the 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.

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

	Year Ended December 31,			Period to period change	
Average realized pricing:	**2013**	**2012**	**2011**	**2013-2012**	**2012-2011**
Natural gas equivalent per Mcfe	$ 3.92	$ 2.88	$ 4.10	$ 1.04	$ (1.22)
Cash settlements on derivative financial instruments, per Mcfe	0.26	1.06	0.74	(0.80)	0.32
Net price per Mcfe, including derivative financial instruments	$ 4.18	$ 3.94	$ 4.84	$ 0.24	$ (0.90)

Our total cash settlements for 2013 were $42.1 million, or $0.26 per Mcfe compared to cash settlements of $202.1 million, or $1.06 per Mcfe in 2012 and $135.4 million, or $0.74 per Mcfe, in 2011. As noted above, the significant fluctuations between settlements on our derivative financial instruments demonstrate the volatility in 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. 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.

Equity income (loss)

Our equity income (loss) for the years ended December 31, 2013, 2012 and 2011 was a net loss of $53.3 million, net income of $28.6 million and $32.7 million, respectively. The decrease for the year ended December 31, 2013 compared to the year ended December 31, 2012 was primarily due to the $86.8 million other than temporary impairment of our investment in TGGT in 2013. Equity loss from our investment in OPCO increased $4.7 million from the prior year primarily due to impairment charges on a water management system as a result of low utilization. These decreases were partially offset by an increase in equity income from our investment in our midstream joint venture in Appalachia.

The decrease for the year ended December 31, 2012 compared to the year ended December 31, 2011 was primarily due to lower equity income of $4.3 million from our investment in TGGT. 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. The impact of these impairments was partially offset by higher operating margins as a result of effective cost-cutting initiatives.

See "Note 14. Equity investments" in the Notes to our Consolidated Financial Statements for further information related to our investments accounted for under the equity method. The sale of TGGT during the fourth quarter of 2013 will have a significant impact on our equity income (loss) in future periods.

Income taxes

The following table presents a reconciliation of our income tax provision (benefit) for the years ended December 31, 2013, 2012 and 2011.

	Year Ended December 31,		
(in thousands)	**2013**	**2012**	**2011**
Federal income taxes (benefit) provision at statutory rate of 35%	$ 7,772	$ (487,649)	$ 7,909
Increases (reductions) resulting from:			
Goodwill	16,382	—	—
Adjustments to the valuation allowance	(28,865)	544,949	(11,665)
Non-deductible compensation	1,328	1,893	1,760
State taxes net of federal benefit	3,239	(59,406)	1,554
Other	144	213	442
Total income tax provision	$ —	$ —	$ —

During 2013, 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 2013.

During 2012, our net loss was significantly impacted by ceiling test write downs. The tax benefits arising from the ceiling test impairments were offset by a valuation allowance. 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 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.

As of December 31, 2013, 2012, and 2011, there were no unrecognized tax benefits, including interest and penalties, that would be required to be recognized in our 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 2005. The Company was notified during the year ended December 31, 2013 that the corporate tax return for the year ended December 31, 2011 would be examined by the Internal Revenue Service. In addition, two pass-through entities in which the Company owns an interest will also be examined for the year ended December 31, 2010.

Pro forma financial information

As discussed in "Note 3. Acquisitions, divestitures and other significant events" in the Notes to our Consolidated Financial Statements, the EXCO/HGI Partnership was formed on February 14, 2013, which resulted in the reduction of our economic interest in certain oil and natural gas properties contributed to the partnership. On March 5, 2013, the EXCO/HGI Partnership purchased the remaining shallow Cotton Valley assets in the East Texas/North Louisiana JV from an affiliate of BG Group. During the third quarter of 2013, we closed the acquisitions of oil and natural gas properties in the Haynesville and Eagle Ford shale formations from Chesapeake. The following table presents selected pro forma operating and financial information for the years ended December 31, 2013, 2012 and 2011 as if these transactions had occurred on January 1, 2011:

	Year ended December 31, 2013			
(dollars in thousands, except per unit rate)	**Historical EXCO**	**EXCO/HGI Partnership pro forma adjustments**	**Chesapeake Properties pro forma adjustments**	**Pro forma EXCO**
Production:				
Total production (Mmcfe)	161,907	(2,705)	27,279	186,481
Average production (Mmcfe/d)	444	(7)	75	512
Revenues:				
Oil and natural gas revenues	$ 634,309	$ (12,657)	$ 150,319	$ 771,971
Average realized price ($/Mcfe)	3.92	4.68	5.51	4.14
Expenses:				
Direct operating costs	61,277	(3,489)	22,564	80,352
Per Mcfe	0.38	1.29	0.83	0.43
Production and ad valorem taxes	21,971	(1,545)	5,965	26,391
Per Mcfe	0.14	0.57	0.22	0.14
Gathering and transportation (1)	100,645	(782)	—	99,863
Per Mcfe	0.62	0.29	—	0.54
Excess of revenues over operating expenses	450,416	(6,841)	121,790	565,365

	Year ended December 31, 2012			
(dollars in thousands, except per unit rate)	**Historical EXCO**	**EXCO/HGI Partnership pro forma adjustments**	**Chesapeake Properties pro forma adjustments**	**Pro forma EXCO**
Production:				
Total production (Mmcfe)	189,928	(25,077)	46,414	211,265
Average production (Mmcfe/d)	519	(69)	127	577
Revenues:				
Oil and natural gas revenues	$ 546,609	$ (111,276)	$ 168,677	$ 604,010
Average realized price ($/Mcfe)	2.88	4.44	3.63	2.86
Expenses:				
Direct operating costs	77,127	(29,081)	28,173	76,219
Per Mcfe	0.41	1.16	0.61	0.36
Production and ad valorem taxes	27,483	(13,379)	9,217	23,321
Per Mcfe	0.14	0.53	0.20	0.11
Gathering and transportation (1)	102,875	(7,892)	—	94,983
Per Mcfe	0.54	0.31	—	0.45
Excess of revenues over operating expenses	339,124	(60,924)	131,287	409,487

	Year ended December 31, 2011			
(dollars in thousands, except per unit rate)	Historical EXCO	EXCO/HGI Partnership pro forma adjustments	Chesapeake Properties pro forma adjustments	Pro forma EXCO
Production:				
Total production (Mmcfe)	184,176	(19,280)	28,160	193,056
Average production (Mmcfe/d)	505	(53)	77	529
Revenues:				
Oil and natural gas revenues	$ 754,201	$ (155,743)	$ 101,343	$ 699,801
Average realized price ($/Mcfe)	4.10	8.08	3.60	3.62
Expenses:				
Direct operating costs	84,766	(36,525)	8,600	56,841
Per Mcfe	0.46	1.89	0.31	0.29
Production and ad valorem taxes	23,875	(13,967)	3,204	13,112
Per Mcfe	0.13	0.72	0.11	0.07
Gathering and transportation (1)	86,881	(8,375)	—	78,506
Per Mcfe	0.47	0.43	—	0.41
Excess of revenues over operating expenses	558,679	(96,876)	89,539	551,342

(1) The oil and natural gas revenues for the Chesapeake Properties are presented net of gathering and treating expenses.

The pro forma information is not necessarily indicative of what actually would have occurred if the transaction had been completed as of January 1, 2011, 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 conditions are favorable. Factors that could impact our liquidity, capital resources and capital commitments in 2014 and future years include the following:

- the level of planned drilling activities;
- the results of our ongoing drilling programs;
- our ability to fund, finance or repay financing incurred in connection with acquisitions of oil and natural gas properties;
- the integration of acquisitions of oil and natural gas properties or other assets;
- our ability to effectively manage operating, general and administrative expenses and capital expenditure programs;
- reduced oil and natural gas revenues resulting from, among other things, depressed oil and natural gas prices and lower production from reductions to our drilling and development activities;
- our ability to mitigate commodity price volatility with derivative financial instruments;
- our ability to meet minimum volume commitments under firm transportation agreements and other fixed commitments;
- potential acquisitions and/or sales of oil and natural gas properties or other assets, including our ability to obtain financing in order to fund the acquisition of properties under the KKR Participation Agreement;
- reductions to our borrowing base; and
- our ability to maintain compliance with debt covenants.

Recent events affecting liquidity

In July 2013, we closed the acquisition of oil and natural gas assets in the Haynesville and Eagle Ford shale formations from Chesapeake. We amended and restated the EXCO Resources Credit Agreement to facilitate these acquisitions, which increased the borrowing base to $1.6 billion, including a $1.3 billion revolving commitment and a $300.0 million term loan. The amendment to the EXCO Resources Credit Agreement also included a $400.0 million asset sale requirement. The interest rate on borrowings under the revolving commitment of the EXCO Resources Credit Agreement was increased by 100 basis points while the asset sale requirement was outstanding. Proceeds from the sale of properties under the KKR Participation Agreement on July 31, 2013 and proceeds from the sale of our equity interest in TGGT on November 15, 2013 were used to reduce outstanding borrowings under the EXCO Resources Credit Agreement. After giving effect to these transactions, the EXCO Resources Credit Agreement borrowing base and outstanding borrowings were reduced by $371.1 million and our asset sale requirement was reduced to $28.9 million as of December 31, 2013.

We closed the Rights Offering and related private placement on January 17, 2014 which resulted in the issuance of 54,574,734 shares of our common stock for net proceeds of $272.9 million. We used the net proceeds to pay indebtedness under the EXCO Resources Credit Agreement, including payment in full of the remaining indebtedness related to the asset sale requirement as well as a portion of the indebtedness outstanding under the revolving commitment under the EXCO Resources Credit Agreement. Upon repayment of the asset sale requirement, the interest rate on the revolving commitment decreased by 100 basis points. The repayments of indebtedness under asset sale requirement resulted in a corresponding reduction in our borrowing base. After giving effect to the Rights Offering and the related transactions under the Investment Agreements, the available borrowing base on the revolving commitment under the EXCO Resources Credit Agreement was $900.0 million with approximately $491.0 million of outstanding indebtedness and approximately $402.1 million of unused borrowing base, net of letters of credit. We expect to receive approximately $65.0 million upon closing of the sale of our interest in a joint venture including producing wells and undeveloped acreage in the Permian Basin. This transaction is expected to close in the first or second quarter of 2014, and we plan to utilize the proceeds to repay indebtedness under the EXCO Resources Credit Agreement.

While 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, there are certain risks and uncertainties that could negatively impact our results of operations and financial condition. The next borrowing base redetermination for the EXCO Resources Credit Agreement will occur in April 2014. Reductions in our borrowing capacity as a result of a redetermination to our borrowing base could have an impact on our capital resources and liquidity. Accordingly, our ability to effectively manage our capital budget is critical to our financial condition, liquidity and our results of operations.

The following table presents information relating to our liquidity as of December 31, 2013 as well as on a pro forma basis as if the closing of the Rights Offering had occurred on December 31, 2013. The pro forma information is not considered to be complete and excludes the impact of all other transactions subsequent to December 31, 2013.

(in thousands)	December 31, 2013	Pro forma
Cash (1) (2)	$ 66,518	$ 66,518
Revolving credit facility under the EXCO Resources Credit Agreement	735,000	490,992
Asset sale requirement under the EXCO Resources Credit Agreement	28,866	—
Term loan under the EXCO Resources Credit Agreement (3)	298,500	298,500
2018 Notes (4)	750,000	750,000
Total debt (5)	$ 1,812,366	$ 1,539,492
Net debt	$ 1,745,848	$ 1,472,974
Borrowing base (6)	$ 1,228,866	$ 1,200,000
Unused borrowing base (7)	$ 158,112	$ 402,120
Unused borrowing base plus cash (1) (7)	$ 224,630	$ 468,638

(1) Includes restricted cash of $20.6 million at December 31, 2013.
(2) Excludes our proportionate share of cash related to the EXCO/HGI Partnership of $4.5 million at December 31, 2013.
(3) Excludes unamortized discount of $2.8 million at December 31, 2013.
(4) Excludes unamortized discount of $7.3 million at December 31, 2013.
(5) Excludes our proportionate share of the debt related to the EXCO/HGI Partnership of $88.5 million as of December 31, 2013.
(6) Includes the borrowing base for the revolving commitment and term loan under the EXCO Resources Credit Agreement.
(7) Net of $6.9 million in letters of credit and $1.5 million in repayments for the term loan under the EXCO Resources Credit Agreement as of December 31, 2013.

Debt covenants

As of December 31, 2013, our consolidated debt consisted of the EXCO Resources Credit Agreement, the 2018 Notes and our 25.5% proportionate share of the EXCO/HGI Partnership Credit Agreement (see "Note 6. Long-Term Debt" in the Notes to our Consolidated Financial Statements for a further description of each agreement). While our proportionate share of the EXCO/HGI Partnership's debt is consolidated, we are not a guarantor of the debt.

As of December 31, 2013, EXCO and the EXCO/HGI Partnership were in compliance with the financial covenants contained in their respective credit agreements, which are presented in the following table. Management believes the following table contains important information related to our liquidity and compliance with the financial covenants of each agreement. However, the information is not complete and is qualified in its entirety by the terms of the EXCO Resources Credit Agreement and the EXCO/HGI Partnership Credit Agreement.

	As of December 31, 2013				
(dollars in millions)	**Borrowing base**	**Outstanding**	**Covenant type (2)**	**Required ratio (3)**	**Actual ratio**
EXCO Resources:					
EXCO Resources Credit Agreement (1)	$ 1,228.9	$ 1,062.4	Current ratio	> 1.0	1.5
			Leverage ratio	< 4.5	3.6
EXCO/HGI Partnership:					
EXCO/HGI Partnership Credit Agreement (4)	$ 400.0	$ 347.0	Current ratio	> 1.0	3.0
			Leverage ratio	< 4.5	3.6

(1) The borrowing base presented within this table for the EXCO Resources Credit Agreement includes both the revolving commitment and the term loan. The interest rate grid on the revolving credit facility of the EXCO Resources Credit Agreement 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. The interest rate grid was increased by 100 bps per annum until the asset sale requirement was repaid in January 2014. The revolving credit facility portion of the EXCO Resources Credit Agreement matures on July 31, 2018. The interest rate on the term loan portion of the EXCO Resources Credit Agreement is LIBOR (with a floor of 100 bps) plus 400 bps (or ABR plus 300 bps). The term loan portion of the EXCO Resources Credit Agreement matures on August 19, 2019.
(2) As defined in the respective credit agreements.
(3) Maximum leverage permitted, or minimum coverage required per the respective credit agreement.
(4) Interest rates range from LIBOR plus 175 bps to 275 bps or (ABR plus 75bps to 175 bps) depending on borrowing base usage. The EXCO/HGI Partnership Credit Agreement matures on February 14, 2018.

The 2018 Notes mature in September 2018 and have a fixed interest rate of 7.5%. The indenture governing the 2018 Notes contains incurrence covenants which restrict our ability to incur additional indebtedness or pledge assets.

There are certain risks arising from the depressed oil and/or natural gas prices that could impact our ability to meet debt covenants in future periods. In particular, our leverage ratio, 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 credit agreement. Our results of operations, cash flows from operations and Proved Reserves were reduced by the 74.5% economic interest in the EXCO/HGI Partnership acquired by HGI in the first quarter of 2013. As a result, our ability to maintain compliance with this covenant is negatively impacted when oil and/or natural gas prices and/or production decline over an extended period of time. In addition, our recent acquisitions in the Eagle Ford and Haynesville shale formations resulted in a significant increase in our consolidated indebtedness. Our ability to maintain compliance with our financial covenants is dependent on our ability to effectively integrate these properties as well as their future development and production.

Furthermore, the increase in our indebtedness may limit our ability to pay dividends as a result of covenants within the EXCO Resources Credit Agreement which states that we may declare and pay cash dividends on our common stock in an amount not to exceed a cumulative total of $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 revolving commitment, as defined in the EXCO Resources Credit Agreement, 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, 2013, we had approximately 18% of the revolving commitment available under the EXCO Resources Credit Agreement. As a result of the repayment of indebtedness from the proceeds of the Rights Offering and related private placement, we had approximately 45% of the revolving commitment available under the EXCO Resources Credit Agreement as of January 17, 2014. As a result of the issuance of additional shares of our common stock in connection with the Rights Offering, we will be required to reduce our dividends in order to maintain compliance with the annual limitation of $50.0 million under the EXCO Resources Credit Agreement unless we are able to amend the related covenant.

Capital commitments

We entered into the KKR Participation Agreement to mitigate the impact of development expenditures on our capital resources and liquidity. EXCO is required to offer to purchase KKR's 75% working interest in wells drilled that have been on production for approximately one year. These offers will be made on a quarterly basis for groups of wells based on a price defined in the KKR Participation Agreement, subject to specific well criteria and return hurdles. The value of EXCO's offers will be based on the PV-10 of the producing properties within each quarterly tranche of wells that have been on production for approximately one year. The pricing used in determining the PV-10 value will be based on NYMEX WTI futures contracts for 60 months then held constant for oil, NYMEX Henry Hub futures contracts for 60 months then held constant for natural gas, and the trailing 12 month actual NGL prices realized relative to WTI prices for NGLs. If EXCO and KKR are unable to agree upon the PV-10 value, an independent external engineering firm will be engaged to provide an independent valuation. The required return utilized in the offer acceptance process is based on 120% of KKR's total invested capital for the wells within each quarterly tranche. The total invested capital used in the calculation of required return is reduced by the cash flows from the production of the wells prior to the offer date. KKR is required to accept the offer if it exceeds the required return. If the PV-10 value exceeds KKR's required return on investment, then EXCO and KKR will share the excess returns in the determination of the purchase price. This will result in a purchase price less than the PV-10 value. KKR has a right to retain an undivided 15% of their collective interest in the quarterly tranche of wells included in each offer. These acquisitions are expected to increase the borrowing base under the revolving commitment of the EXCO Resources Credit Agreement, and the acquisitions are expected to be funded with borrowings under the EXCO Resources Credit Agreement, cash flows from operations, or alternative financing arrangements.

During 2013, we spud 23 wells under the KKR Participation Agreement and these wells are expected to be included within the first quarterly buyback in the first quarter of 2015. The timing of these buybacks is dependent upon the date these wells are turned-to-sales and the downtime during the year preceding the offer process. KKR's share of the average development and completion costs per well to be included within the first quarterly buyback is approximately $3.5 million. During 2013, there were 7 wells turned-to-sales and KKR's share of the revenues less operating expenses for these wells was $5.7 million. Prior to buybacks in future periods, our average working interest in wells developed under this agreement is approximately 17% and KKR's average working interest is approximately 50%. The remaining working interest is held by other third-party owners and is not part of the buyback program. During 2014, we expect to spud 84 wells which will be included in future buybacks beginning in the second quarter of 2015.

While we are required to make offers to purchase KKR's interest on certain wells, we may not have sufficient funds or borrowing capacity under the EXCO Resources Credit Agreement to complete the acquisitions. In the event we fail to purchase a group of wells that KKR is obligated to sell, there are remedies available to KKR which allow KKR to reject future EXCO offers, terminate the KKR Participation Agreement, or pursue other legal remedies. This could require us to seek alternative financing to make offers to preserve KKR's obligation to sell to us, or negatively impact our ability to increase our Eagle Ford assets via acquisitions of KKR's producing properties. See Item "1A—Risk Factors. If we are unable to complete the joint development of our assets in the Eagle Ford shale formations with KKR, we may need to find alternative sources of capital, which may not be available on favorable terms, if at all."

Historical sources and uses of funds

Our primary sources of cash in 2013 were cash flows from operations, borrowings under the EXCO Resources Credit Agreement and proceeds from the sale of assets. We utilized borrowings under the EXCO Resources Credit Agreement to fund the acquisition of the Chesapeake Properties. We have focused on efficiently managing our capital expenditures as part of our increased development program due to our recent acquisitions.

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

(in thousands)	Year Ended December 31, 2013	2012	2011
Net cash provided by operating activities	$ 350,634	$ 514,786	$ 428,543
Net cash used in investing activities	(252,478)	(427,094)	(709,531)
Net cash provided by (used in) financing activities	(93,317)	(74,045)	268,756
Net increase (decrease) in cash	$ 4,839	$ 13,647	$ (12,232)

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, natural gas and natural gas liquids 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. Our cash flows from operating activities have historically been impacted by fluctuations in oil and natural gas prices and our production volumes.

Net cash provided by operating activities for the year ended December 31, 2013 was $350.6 million as compared to $514.8 million for the year ended December 31, 2012. The decrease is primarily attributable to lower settlement proceeds on our derivatives and less favorable working capital conversions. Settlements on derivative contracts decreased by $160.0 million for the year ended December 31, 2013 as compared to the year ended December 31, 2012. The cash inflows from the acquisition of the Chesapeake Properties and higher realized oil and natural gas prices were partially offset by lower production primarily due to our contribution of properties to the EXCO/HGI Partnership.

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 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.

Investing activities

Our investing activities consist primarily of drilling and development expenditures, acquisitions and divestitures. Our recent acquisition of the Chesapeake Properties was directed toward producing properties with additional undeveloped upside potential. Future acquisitions are dependent on oil and natural gas prices, availability of producing properties and attractive acreage, acceptable rates of return and availability of borrowing capacity under the EXCO Resources Credit Agreement or from other capital sources.

For the year ended December 31, 2013, our cash flows used in investing activities were $252.5 million, as compared with $427.1 million of cash flows used in investing activities for the year ended December 31, 2012. Our property acquisitions during 2013 were primarily attributable to the acquisition of the Chesapeake Properties of $942.9 million and our proportionate share of the EXCO/HGI Partnership's acquisition of the shallow Cotton Valley assets from an affiliate of BG Group. Our capital expenditures of $320.5 million were primarily focused on our development program in the East Texas/North Louisiana and South Texas regions. The cash used in investing activities was partially offset by the $574.8 million in proceeds as a result of the contribution of properties to the EXCO/HGI Partnership, the sale of our equity investment in TGGT of $236.6 million, net of commissions and fees, the sale of undeveloped acreage to KKR for $130.9 million and other asset divestitures of $37.9 million.

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. The decrease was primarily attributable to reductions in our drilling program in response to a decline in natural gas prices. 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.

Financing activities

For the year ended December 31, 2013, our cash flows used in financing activities were $93.3 million. The cash flows used in financing activities were primarily attributable to borrowings of approximately $1.0 billion under the EXCO Resources Credit Agreement to fund the acquisition of the Chesapeake Properties and the additional borrowings of the EXCO/HGI Partnership to fund the acquisition of shallow Cotton Valley assets from an affiliate of BG Group. These borrowings were offset by total repayments of our EXCO Resources Credit Agreement of approximately $1.0 billion which consisted of the application of proceeds from the contribution of properties to the EXCO/HGI Partnership, the sale of undeveloped acreage to

KKR, the sale of TGGT, cash flows from operations and other asset sales. We utilized borrowings under the EXCO Resources Credit Agreement to pay deferred financing costs associated with the amendment to facilitate the acquisition of the Chesapeake Properties. We paid $43.2 million of dividends on our common stock during 2013.

For the year ended December 31, 2012, our cash flows used in financing activities were $74.0 million. The cash flows used in investing activities primarily consisted of net repayments of indebtedness under the EXCO Resources Credit Agreement of $40.0 million. We paid $34.4 million of dividends on our common stock during 2012.

For the year ended December 31, 2011, our cash flows provided by financing activities were $268.8 million. The cash flows provided by financing activities primarily consisted of net borrowings of $298.5 million under the EXCO Resources Credit Agreement to fund the acquisitions of properties in the Marcellus shale and the Haynesville shale. We also received $12.1 million for the issuance of common stock as a result of the exercise of stock options by employees. We paid $34.2 million of dividends on our common stock during 2011.

Capital expenditures

During 2013, our capital expenditures primarily consisted of our acquisitions of Haynesville and Eagle Ford assets as well as our development programs in these regions. The oil and natural gas property acquisitions of $942.9 million during 2013 included the Eagle Ford and Haynesville assets acquired from Chesapeake. In connection with closing the acquisition of the Eagle Ford assets, we entered into the KKR Participation Agreement and sold an undivided 50% interest in the undeveloped acreage we acquired for approximately $130.9 million. Our development program during 2013 focused on our properties in the Haynesville and Eagle Ford shales. We operated three drilling rigs throughout 2013 in the Haynesville shale focused on our core area in DeSoto and Caddo Parish, Louisiana. We continued to emphasize cost containment and reducing our drilling and completion costs. We began our development program in the Eagle Ford shale which included three to four operated drilling rigs from the date we acquired the properties to year-end. We also incurred additional expenditures in this region for surface acreage, infrastructure and operating facilities. Our expenditures in the Appalachia region focused on a limited appraisal drilling program, completion activities and the construction of pads for future drilling activity.

During 2012, our capital expenditures primarily focused on our development program in the Haynesville shale as well as our appraisal and development program in the Marcellus shale. We significantly reduced our capital expenditures during 2012 as a result of the decline in natural gas prices. We also had a limited development program in the Permian Basin focused on conventional assets which were contributed to the EXCO/HGI Partnership during 2013. Our lease purchases during 2012 were primarily in the Permian Basin on acreage with horizontal drilling potential.

During 2011, our oil and natural gas property acquisitions consisted of the acquisition of Haynesville shale assets as wells as Marcellus shale assets including $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 developmental capital expenditures were primarily focused on the Haynesville shale concentrated on DeSoto Parish and the Shelby area, and the early stages of our appraisal and development programs in the Marcellus shale. We also had a limited development program in the Permian Basin focused on conventional assets which were contributed to the EXCO/HGI Partnership during 2013. Our lease purchases during 2011 primarily consisted of undeveloped acreage in the Haynesville/Bossier shale and Marcellus shale.

The following table presents our capital expenditures for the years ended December 31, 2013, 2012 and 2011. These capital expenditures exclude the EXCO/HGI Partnership, which funded its capital expenditures through internally generated cash flow and credit agreement.

	Year Ended December 31,		
(in thousands)	**2013**	**2012**	**2011**
Capital expenditures:			
Oil and natural gas property acquisitions (1) (2)	$ 942,946	$ 3,349	$ 755,520
Lease purchases (3)	14,835	46,678	63,367
Development capital expenditures	265,120	403,342	855,451
Seismic	10,217	2,480	10,146
Field operations, gathering and water pipelines	12,379	1,044	6,495
Corporate and other	37,287	48,303	65,747
Total capital expenditures	$ 1,282,784	$ 505,196	$ 1,756,726

(1) The oil and natural gas property acquisitions of $942.9 million during 2013 included the Eagle Ford and Haynesville assets acquired from Chesapeake. This amount was reduced by $130.9 million from the sale of a portion of the undeveloped acreage we acquired in the Eagle Ford shale to KKR.
(2) Excludes reimbursements from BG Group of $359.1 million in 2011. There were no reimbursements from BG Group in 2013 and 2012.
(3) Excludes reimbursements from BG Group $2.1 million in 2012 and $31.9 million in 2011. There were no reimbursements from BG Group in 2013.

2014 capital budget

Our board of directors approved a capital budget of $368.0 million for 2014, of which $294.0 million is allocated to development and completion activities. Our developmental activities in the East Texas/North Louisiana region are primarily focused on our core area in DeSoto Parish as well as a limited drilling program in the Shelby area. In the South Texas region, our developmental activities will primarily be focused on our core area as part of the participation agreement with KKR. We believe the capital budget is appropriate for current commodity prices and our capital structure. Our capital program was designed to manage our capital expenditures in relation to our operating cash flow. These capital expenditures exclude the EXCO/HGI Partnership, which funds its capital expenditures through internally generated cash flow and its credit agreement, and also exclude any capital expenditures for our joint development of shale properties in the Permian Basin. The 2014 capital budget is currently allocated among the different budget categories as follows:

(in millions, except wells)	Gross Wells Spud (1)	Net Wells Spud (1)	Net Wells Completed (1)	Drilling & Completion	Other Capital	Total Capital
East Texas/North Louisiana	42	20.5	18.3	$ 173	$ 11	$ 184
South Texas	90	15.2	14.3	109	29	138
Appalachia	2	0.5	0.5	12	5	17
Corporate and other (2)	—	—	—	—	29	29
Total	134	36.2	33.1	$ 294	$ 74	$ 368

(1) The wells spud and completed within this table only include those operated by EXCO.
(2) Includes $18 million of capitalized interest.

Derivative financial instruments

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 commodity 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.

Our derivative financial instruments are comprised of oil and natural gas swaps, basis swaps and call option contracts. As of December 31, 2013, we had derivative financial instruments in place for the volumes and prices shown below:

(in thousands, except prices)	NYMEX gas volume - Mmbtu	Weighted average contract price per Mmbtu	NYMEX oil volume - Bbls	Weighted average contract price per Bbl
Swaps:				
2014	84,060	$ 4.22	1,644	$ 95.03
2015	28,288	4.31	548	91.78
Basis Swaps:				
2014	—	—	183	6.03
2015	—	—	91	6.10
Call options:				
2014	20,075	4.29	365	100.00
2015	20,075	4.29	365	100.00

We proportionately consolidate the derivative financial instruments entered into by the EXCO/HGI Partnership. However, we are not liable in the event of default on the EXCO/HGI Partnership's derivative contracts. As of December 31, 2013, our proportionate share of the EXCO/HGI Partnership's natural gas derivative swap contracts included approximately 15,000 Mmbtu per day at an average price of $4.15 during 2014. Our proportionate share of the EXCO/HGI Partnership's oil derivative swap contracts included approximately 255 Bbls per day at an average price of $91.87 during 2014. The EXCO/HGI Partnership had derivative financial instruments that covered approximately 77% of production volumes during the period from its inception until December 31, 2013.

See further details on our derivative financial instruments in "Note 4. Derivative financial instruments" and "Note 5. Fair value measurements" in the Notes to our Consolidated Financial Statements.

Off-balance sheet arrangements

As of December 31, 2013, 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, 2013:

	Payments due by period				
(in thousands)	**Less than one year**	**One to three years**	**Three to five years**	**More than five years**	**Total**
EXCO Resources Credit Agreement (1)	$ 31,866	$ 6,000	$ 741,000	$ 283,500	$ 1,062,366
2018 Notes (2)	—	—	750,000	—	750,000
Firm transportation services (3)	136,376	269,469	262,000	190,678	858,523
Other fixed commitments (4)	14,532	30,525	8,625	5,929	59,611
Drilling contracts	40,286	—	—	—	40,286
Operating leases and other	8,055	6,536	140	—	14,731
Total contractual obligations (5) (6)	$ 231,115	$ 312,530	$ 1,761,765	$ 480,107	$ 2,785,517

(1) The EXCO Resources Credit Agreement includes both the revolving commitment and the term loan. The revolving commitment included the asset sale requirement of $28.9 million which was repaid on January 17, 2013. The interest rate grid on the revolving credit facility of the EXCO Resources Credit Agreement 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. The revolving credit facility portion of the EXCO Resources Credit Agreement matures on July 31, 2018. The interest rate on the term loan portion of the EXCO Resources Credit Agreement is LIBOR (with a floor of 100 bps) plus 400 bps (or ABR plus 300 bps). The term loan portion of the EXCO Resources Credit Agreement matures on August 19, 2019.

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

(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 and minimum sales commitments under marketing contracts.

(5) Excludes commitments of our equity method investees as neither EXCO nor any of its subsidiaries are guarantors of these commitments. OPCO's total commitments as of December 31, 2013, which consisted primarily of firm transportation contracts, drilling contracts and completion services, totaled $39.1 million.

(6) Excludes commitments of the EXCO/HGI Partnership as neither EXCO nor any of its subsidiaries are guarantors of these commitments. The EXCO/HGI Partnership's total commitments as of December 31, 2013, which consisted primarily of borrowings under the EXCO/HGI Partnership Credit Agreement, totaled $347.7 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.

Our most significant 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.

Our use of derivative financial instruments could have the effect of reducing our revenues and the value of our securities. For the year ended December 31, 2013, 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 $91.9 million. The ultimate settlement amount of our outstanding 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.

Interest rate risk

At December 31, 2013, our exposure to interest rate changes related primarily to borrowings under the EXCO Resources Credit Agreement and the EXCO/HGI Partnership Credit Agreement. 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, 2013, we had approximately $1.1 billion in outstanding borrowings under the EXCO Resources Credit Agreement, including the revolving commitment and the term loan, and $88.5 million for our proportionate share of outstanding borrowings under the EXCO/HGI Partnership Credit Agreement. A 1% change in interest rates (100 bps) based on the variable borrowings as of December 31, 2013 would result in an increase or decrease in our interest expense of approximately $8.6 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, 2013. 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 (1992)*. Based on management's assessment, management believes that, as of December 31, 2013, 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, 2013 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which appears herein.

By:	/s/ Harold L. Hickey	By:	/s/ Mark F. Mulhern
Title:	President and Chief Operating Officer	Title:	Executive Vice President, Chief Financial Officer and interim Chief Accounting Officer

Dallas, Texas
February 26, 2014

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of EXCO Resources, Inc. and subsidiaries as of December 31, 2013 and 2012, 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, 2013. We also have audited EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* 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, 2013 and 2012, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2013, 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, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Dallas, Texas
February 26, 2014

EXCO RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(in thousands)	December 31, 2013	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$ 50,483	$ 45,644
Restricted cash	20,570	70,085
Accounts receivable, net:		
Oil and natural gas	128,352	84,348
Joint interest	70,759	69,446
Other	18,022	15,053
Inventory	3,087	5,705
Derivative financial instruments	8,226	49,500
Other	6,355	22,085
Total current assets	305,854	361,866
Equity investments	57,562	347,008
Oil and natural gas properties (full cost accounting method):		
Unproved oil and natural gas properties and development costs not being amortized	425,307	470,043
Proved developed and undeveloped oil and natural gas properties	3,554,210	2,715,767
Accumulated depletion	(2,183,464)	(1,945,565)
Oil and natural gas properties, net	1,796,053	1,240,245
Gathering assets	33,473	130,830
Accumulated depreciation and amortization	(10,338)	(34,364)
Gathering assets, net	23,135	96,466
Office, field and other equipment, net	27,204	20,725
Deferred financing costs, net	28,807	22,584
Derivative financial instruments	6,829	16,554
Goodwill	163,155	218,256
Other assets	29	28
Total assets	$ 2,408,628	$ 2,323,732

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share and share data)	December 31, 2013	December 31, 2012
Liabilities and shareholders’ equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 132,188	$ 83,240
Revenues and royalties payable	154,862	134,066
Accrued interest payable	18,144	17,029
Current portion of asset retirement obligations	191	1,200
Income taxes payable	—	—
Derivative financial instruments	11,919	2,396
Current maturities of long-term debt	31,866	—
Total current liabilities	349,170	237,931
Long-term debt	1,858,912	1,848,972
Deferred income taxes	—	—
Derivative financial instruments	9,671	26,369
Asset retirement obligations and other long-term liabilities	42,970	61,067
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; 218,783,540 shares issued and 218,244,319 shares outstanding at December 31, 2013; 218,126,071 shares issued and 217,586,850 shares outstanding at December 31, 2012	215	215
Subscription rights, $0.001 par value, 54,574,734 issued and outstanding at December 31, 2013	55	—
Additional paid-in capital	3,219,748	3,200,067
Accumulated deficit	(3,064,634)	(3,043,410)
Treasury stock, at cost; 539,221 shares at December 31, 2013 and December 31, 2012	(7,479)	(7,479)
Total shareholders’ equity	147,905	149,393
Total liabilities and shareholders’ equity	$ 2,408,628	$ 2,323,732

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share data)	Year Ended December 31, 2013	2012	2011
Revenues:			
Oil	$ 111,440	$ 62,119	$ 67,440
Natural gas liquids	8,560	22,068	29,639
Natural gas	514,309	462,422	657,122
Total revenues	634,309	546,609	754,201
Costs and expenses:			
Oil and natural gas operating costs	61,277	77,127	84,766
Production and ad valorem taxes	21,971	27,483	23,875
Gathering and transportation	100,645	102,875	86,881
Depletion, depreciation and amortization	245,775	303,156	362,956
Impairment of oil and natural gas properties	108,546	1,346,749	233,239
Accretion of discount on asset retirement obligations	2,514	3,887	3,652
General and administrative	91,878	83,818	104,618
(Gain) loss on divestitures and other operating items	(177,518)	17,029	23,819
Total costs and expenses	455,088	1,962,124	923,806
Operating income (loss)	179,221	(1,415,515)	(169,605)
Other income (expense):			
Interest expense, net	(102,589)	(73,492)	(61,023)
Gain (loss) on derivative financial instruments	(320)	66,133	219,730
Other income (expense)	(828)	969	788
Equity income (loss)	(53,280)	28,620	32,706
Total other income (expense)	(157,017)	22,230	192,201
Income (loss) before income taxes	22,204	(1,393,285)	22,596
Income tax expense	—	—	—
Net income (loss)	$ 22,204	$ (1,393,285)	$ 22,596
Earnings (loss) per common share:			
Basic:			
Net income (loss)	$ 0.10	$ (6.50)	$ 0.11
Weighted average common shares outstanding	215,011	214,321	213,908
Diluted:			
Net income (loss)	$ 0.10	$ (6.50)	$ 0.10
Weighted average common shares and common share equivalents outstanding	230,912	214,321	216,705

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)	Year Ended December 31, 2013	2012	2011
Operating Activities:			
Net income (loss)	$ 22,204	$ (1,393,285)	$ 22,596
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	245,775	303,156	362,956
Share-based compensation expense	10,748	8,926	11,012
Accretion of discount on asset retirement obligations	2,514	3,887	3,652
Impairment of oil and natural gas properties	108,546	1,346,749	240,039
(Income) loss from equity investments	53,280	(28,620)	(32,706)
(Gain) loss on derivative financial instruments	320	(66,133)	(219,730)
Cash settlements of derivative financial instruments	42,119	202,078	135,417
Deferred income taxes	—	—	—
Amortization of deferred financing costs and discount on debt issuance	29,624	9,788	9,759
(Gain) loss on divestitures and other non-operating items	(185,163)	1,303	(479)
Effect of changes in:			
Accounts receivable	(46,176)	112,919	(79,359)
Other current assets	9,627	7,090	(5,961)
Accounts payable and other current liabilities	57,216	6,928	(18,653)
Net cash provided by operating activities	350,634	514,786	428,543
Investing Activities:			
Additions to oil and natural gas properties, gathering assets and equipment	(320,538)	(534,175)	(984,085)
Property acquisitions	(976,714)	(2,748)	(753,286)
Proceeds from disposition of property and equipment	749,628	38,045	449,683
Restricted cash	49,515	85,840	5,792
Net changes in advances to joint ventures	10,645	851	(1,707)
Equity method investments	236,289	(14,907)	111,171
Deposit on acquisitions	—	—	464,151
Other	(1,303)	—	(1,250)
Net cash used in investing activities	(252,478)	(427,094)	(709,531)
Financing Activities:			
Borrowings under credit agreements	1,004,523	53,000	706,000
Repayments under credit agreements	(1,022,785)	(93,000)	(407,500)
Proceeds from issuance of common stock	1,712	1,968	12,063
Payment of common stock dividends	(43,214)	(34,358)	(34,238)
Deferred financing costs and other	(33,553)	(1,655)	(7,569)
Net cash provided by (used in) financing activities	(93,317)	(74,045)	268,756
Net increase (decrease) in cash	4,839	13,647	(12,232)
Cash at beginning of period	45,644	31,997	44,229
Cash at end of period	$ 50,483	$ 45,644	$ 31,997
Supplemental Cash Flow Information:			
Cash interest payments	$ 88,936	$ 86,298	$ 78,125
Income tax payments	—	—	1,458
Supplemental non-cash investing and financing activities:			
Capitalized share-based compensation	$ 7,288	$ 7,513	$ 6,406
Capitalized interest	18,729	23,809	30,083
Issuance of common stock for director services	93	597	70
Accrued restricted stock dividends	214	300	129
Debt assumed upon formation of EXCO/HGI Partnership, net	58,613	—	—
Issuance of subscription rights	55	—	—

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(in thousands)	Common Stock		Subscription Rights		Treasury Stock		Additional paid-in capital	Accumulated deficit	Total shareholders' equity
	Shares	Amount	Shares	Amount	Shares	Amount			
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
Issuance of common stock	228	—	—	—	—	—	1,805	—	1,805
Share-based compensation	—	—	—	—	—	—	17,931	—	17,931
Restricted stock issued, net of cancellations	429	—	—	—	—	—	—	—	—
Common stock dividends	—	—	—	—	—	—	—	(43,428)	(43,428)
Issuance of subscription rights	—	—	54,575	55	—	—	(55)	—	—
Net income	—	—	—	—	—	—	—	22,204	22,204
Balance at December 31, 2013	218,783	$ 215	54,575	$ 55	(539)	$ (7,479)	$ 3,219,748	$ (3,064,634)	$ 147,905

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 Texas, Louisiana and the Appalachia region. The following is a brief discussion of our producing regions and the EXCO/HGI Partnership.

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

  The East Texas/North Louisiana region is primarily comprised of our Haynesville and Bossier shale assets. We have a joint venture with BG Group, plc ("BG Group") covering an undivided 50% interest in certain Haynesville/Bossier shale assets in East Texas and North Louisiana ("East Texas/North Louisiana JV"). We previously held certain conventional shallow producing assets that we contributed to the EXCO/HGI Partnership, as defined below, upon its formation on February 14, 2013. We serve as the operator for most of our properties in the East Texas/North Louisiana region.

- ***South Texas***

  The South Texas region is primarily comprised of our Eagle Ford shale assets. We have a joint venture with affiliates of Kohlberg Kravis Roberts & Co. L.P. ("KKR") to develop our Eagle Ford shale assets in South Texas. The South Texas region also includes assets in the Pearsall shale and the Austin Chalk and Buda formations. We serve as the operator for most of our properties in the South Texas region.

- ***Appalachia***

  The Appalachia region is primarily comprised of Marcellus shale assets as well as shallow conventional assets in other formations. We have a joint venture with BG Group covering our shallow producing assets and Marcellus shale properties in the Appalachia region ("Appalachia JV"). EXCO and BG Group each own an undivided 50% interest in the Appalachia JV and a 49.75% working interest in the Appalachia JV's properties. The remaining 0.5% working interest is owned by a jointly owned operating entity ("OPCO") that operates the Appalachia JV's properties. We own a 50% interest in OPCO.

- ***Permian and other***

  Our Permian and other region is comprised of properties in the Permian Basin with horizontal drilling potential and conventional assets in the Mid-Continent region. Our shallow assets in the Permian Basin were contributed to the EXCO/HGI Partnership on February 14, 2013. On March 13, 2013, we closed a sale and joint development agreement with a private party for the sale of an undivided 50% of our interest in certain undeveloped acreage in the Permian basin. We formed a joint venture with the private party to develop our acreage with horizontal drilling potential in the Permian Basin. The private party will serve as the operator. On February 13, 2014, we entered into a purchase and sale agreement with the private party for the sale of our interest in the joint venture including producing wells and undeveloped acreage. See further discussion in "Note 3. Acquisitions, divestitures and other significant events".

- ***EXCO/HGI Partnership***

  A joint venture formed on February 14, 2013, with Harbinger Group Inc. ("HGI") in which we own a 25.5% economic interest in conventional shallow producing assets in East Texas and North Louisiana and shallow Canyon Sand and other assets in the Permian Basin ("EXCO/HGI Partnership").

The accompanying Consolidated Balance Sheets as of December 31, 2013 and 2012, Consolidated Statements of Operations, Consolidated Statements of Cash Flows and Consolidated Statements of Changes in Shareholders’ Equity for the years ended December 31, 2013, 2012 and 2011 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 ("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, 2013 and 2012 and the Consolidated Statements of Operations, Consolidated Statements of Cash Flows and Changes in Shareholders' Equity for the years ended December 31, 2013, 2012 and 2011. Investments in unconsolidated affiliates in which we are able to exercise significant influence are accounted for using the equity method. We use the cost method of accounting for investments in unconsolidated affiliates in which we are not able to exercise significant influence. All intercompany transactions and accounts have been eliminated.

During the year ended December 31, 2013, we sold our equity interest in TGGT Holdings, LLC ("TGGT") which previously made up the majority of our midstream segment. See further discussion of this transaction in "Note 14. Equity investments". Our remaining midstream investments are not considered to be significant and do not meet the disclosure requirements for a separate reportable business segment.

We report our interests in oil and natural gas properties using the proportional consolidation method of accounting. Also, we report our 25.5% interest in the EXCO/HGI Partnership using proportional consolidation. From January 1, 2013 to February 13, 2013, our operating results reflect 100% of our interest in the properties we contributed to the EXCO/HGI Partnership. From February 14, 2013 to December 31, 2013, our operating results reflect 25.5% of our interest in the properties we contributed to the EXCO/HGI Partnership.

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, asset retirement obligations, share-based compensation, 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 was immaterial at both December 31, 2013 and 2012. We place our derivative financial instruments with financial institutions 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, 2013, 2012 and 2011, sales to BG Energy Merchants LLC accounted for approximately 48%, 36% and 36%, respectively, of total consolidated revenues. BG Energy Merchants LLC is a subsidiary of BG Group. For the year ended December 31, 2013, Chesapeake Energy Marketing Inc. accounted for approximately 14% of total consolidated revenues. Chesapeake Energy Marketing Inc. is a subsidiary of Chesapeake Energy Corporation ("Chesapeake").

Derivative financial instruments

In connection with the incurrence of debt related to our acquisition, exploration, exploitation, development and production 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 ("FASB"), Accounting Standards Codification, ("ASC"), Topic 815, *Derivatives and Hedging,* ("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 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 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 $425.3 million and $470.0 million as of December 31, 2013 and 2012, 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 or determination that no proved reserves are attributable to such costs. Our undeveloped properties are predominantly held-by-production, which reduces the risk of impairment as a result of lease expirations. 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. As a result of this evaluation, we impaired approximately $1.0 million and $60.8 million of undeveloped properties during 2013 and 2012, respectively, which were transferred to the depletable portion of the full cost pool during each year. The impairment was recorded to reflect the 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.

We capitalize interest on the costs related to the acquisition of undeveloped acreage 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 related to these properties.

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 acquisition, 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 ("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 impairment 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 12 month period using the first day of each month. For the 12 months ended December 31, 2013, the trailing 12 month reference prices were $3.67 per Mmbtu for natural gas at Henry Hub, and $96.78 per Bbl of oil for West Texas Intermediate at Cushing, Oklahoma. The price used for NGL's was $39.92 per Bbl and was based on the trailing 12 month average of realized prices. 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 impairments of oil and natural gas properties may not be reversed in subsequent periods. Since we do not designate our derivative financial instruments as hedging instruments, we are not allowed to use the impacts of the derivative financial instruments in our ceiling test computations.

As of December 31, 2013 pursuant to Rule 4-10(c)(4) of Regulation S-X, we were required to compute the ceiling test using the simple average spot price for the trailing 12 month period for oil and natural gas. The computation resulted in the carrying costs of our unamortized proved oil and natural gas properties, exceeding the December 31, 2013 ceiling test limitation by approximately $156.6 million, including the recently acquired Haynesville and Eagle Ford properties from Chesapeake ("Chesapeake Properties"). Our pricing for the acquisitions of the Chesapeake Properties was based on models which incorporate, among other things, market prices based on NYMEX futures as of the acquisition date. The ceiling test requires companies using the full cost accounting method to price period-ending proved reserves using the simple average spot price for the trailing 12 month period, which may not be indicative of actual market values. Given the short passage of time between closing of these acquisitions and the required ceiling test computation, the Company requested, and received, an exemption from the Securities and Exchange Commission ("SEC") to exclude the acquisition of the Chesapeake Properties from the ceiling test assessments for a period of 12 months following the corresponding acquisition dates.

If we cannot demonstrate the fair value of the Chesapeake Properties exceeds the unamortized carrying costs during the requested exemption periods prior to issuance of our financial statements, we are required to recognize an impairment. We evaluated the Chesapeake Properties for impairment using discounted cash flow models based on internally generated oil and natural gas reserves as of December 31, 2013. The Company's expectation of future prices is principally based on NYMEX futures contracts, adjusted for basis differentials. We believe the NYMEX futures contract reflects an independent pricing point for determining fair value.

The evaluation of impairment of our oil and natural gas properties includes 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.

For the years ended December 31, 2013, 2012 and 2011 we recognized impairments of $108.5 million, $1.3 billion and $233.2 million, respectively, to our proved oil and natural gas properties.

Gathering assets

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 cost of inventory is capitalized in 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 ranging 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 31 of each year. Losses, if any, resulting from impairment tests will be reflected in operating income in the Consolidated Statements of Operations.

We apply a two-part, equally weighted approach in determining the fair value of our business as part of the goodwill impairment test. 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 our business exceeded the carrying value of net assets and we did not record an impairment charge for the periods ending December 31, 2013, 2012 and 2011.

The contribution of oil and natural gas properties to the EXCO/HGI Partnership resulted in a significant alteration in our depletion rate. In accordance with full cost accounting rules, we recorded a gain of $186.4 million, net of a proportionate reduction in goodwill of $55.1 million, for the year ended December 31, 2013. The balance of goodwill as of December 31, 2013 and 2012 was $163.2 million and $218.3 million, respectively.

Asset retirement obligations

We apply FASB ASC 410-20, *Asset Retirement and Environmental Obligations* ("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)	**2013**	**2012**	**2011**
Asset retirement obligations at beginning of period	$ 61,864	$ 58,088	$ 50,292
Activity during the period:			
Liabilities incurred during the period	514	971	3,765
Revisions in estimated assumptions	1,268	—	—
Liabilities settled during the period	(187)	(338)	(291)
Adjustment to liability due to acquisitions (1)	5,566	—	1,684
Adjustment to liability due to divestitures (2)	(28,585)	(744)	(1,014)
Accretion of discount	2,514	3,887	3,652
Asset retirement obligations at end of period	42,954	61,864	58,088
Less current portion	191	1,200	732
Long-term portion	$ 42,763	$ 60,664	$ 57,356

(1) Adjustment to liability due to acquisitions consisted of $3.0 million from the acquisition of Eagle Ford assets, $1.9 million from our proportionate share of the EXCO/HGI Partnership acquisition of the Cotton Valley assets and $0.6 million from the acquisition of Haynesville assets.

(2) Adjustment to liability due to divestitures consisted primarily of $28.3 million from the contribution of our certain conventional assets to the EXCHO/HGI Partnership.

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, 2013, 2012 and 2011 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 $100.6 million, $102.9 million and $86.9 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Capitalization of internal costs

As part of our proved developed oil and natural gas properties, we capitalize a portion of salaries and related share-based compensation for employees who are directly involved in the acquisition, exploration, exploitation and development of oil and natural gas properties. During the years ended December 31, 2013, 2012 and 2011, we capitalized $18.2 million, $22.5 million and $22.9 million, respectively. The capitalized amounts include $7.3 million, $7.5 million and $6.4 million of share-based compensation for the years ended December 31, 2013, 2012 and 2011, respectively.

Overhead reimbursement fees

We have classified fees from overhead charges billed to working interest owners of $10.5 million, $20.5 million and $18.4 million, for the years ended December 31, 2013, 2012 and 2011, respectively, as a reduction of general and administrative expenses in the accompanying Consolidated Statements of Operations. Our share of these charges was $5.8 million, $10.3 million and $9.6 million for the years ended December 31, 2013, 2012 and 2011, 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. In connection with the formation of the EXCO/HGI Partnership, we entered into an agreement to perform certain operational, managerial, and administrative services. The EXCO/HGI Partnership reimburses us for costs incurred in connection with the performance of these services based on an agreed upon service fee. For the years ended December 31, 2013, 2012 and 2011, general and administrative expenses were reduced by $26.8 million, $25.2 million and $29.1 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* ("ASC 740"), 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"). ASC 260-10 requires companies to present two calculations of earnings per share ("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"). 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 ("2005 Incentive Plan") provides for the granting of options and other equity incentive awards 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.

Recent accounting pronouncement

In February 2013, the FASB issued Accounting Standards Update ("ASU") No. 2013-04, Liabilities (Topic 405): *Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date* ("ASU 2013-04"). ASU 2013-04 provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date, except for obligations addressed within existing guidance in GAAP. The update is effective for interim and annual periods beginning after December 15, 2013 and is required to be applied retrospectively to all prior periods presented for those obligations that existed upon adoption of ASU 2013-04. We do not expect our adoption of ASU 2013-04 to have an impact on our consolidated financial condition and results of operations.

3. Acquisitions, divestitures and other significant events

2013 Acquisitions, divestitures and other significant events

EXCO/HGI Partnership

On February 14, 2013, we formed the EXCO/HGI Partnership. Pursuant to the agreements governing the transaction, we contributed our conventional shallow producing 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 net cash proceeds of $574.8 million, after final purchase price adjustments, and a 25.5% economic interest in the partnership. HGI's economic interest in the EXCO/HGI Partnership is 74.5%. The primary strategy of the EXCO/HGI Partnership is to exploit its current asset base and acquire conventional producing oil and natural gas properties to enhance asset value and cash flow.

The contribution of oil and natural gas properties to the EXCO/HGI Partnership resulted in a significant alteration in our depletion rate. In accordance with full cost accounting rules, we recorded a gain of $186.4 million, net of a proportionate reduction in goodwill of $55.1 million, for the year ended December 31, 2013.

Immediately following the closing, the EXCO/HGI Partnership entered into an agreement to purchase the remaining shallow Cotton Valley assets within the East Texas/North Louisiana JV from an affiliate of BG Group for $130.7 million, after final purchase price adjustments. The assets acquired as a result of this transaction represented an incremental working interest in properties owned by the EXCO/HGI Partnership. The transaction closed on March 5, 2013 and was funded with borrowings from the EXCO/HGI Partnership's credit agreement ("EXCO/HGI Partnership Credit Agreement").

Acreage transaction

On March 13, 2013, we closed a sale and joint development agreement with a private party for the sale of an undivided 50% of our interest in certain undeveloped acreage in the Permian Basin. The private party was designated as the operator under the joint development agreement. We received $37.9 million in cash, after final closing adjustments. In addition to the cash consideration received at closing, the purchaser agreed to fund our share of drilling and completion costs within the joint venture area up to $18.9 million. As of December 31, 2013, there was approximately $5.1 million remaining under the carry.

On February 13, 2014, we entered into a purchase and sale agreement with the private party for the sale of our interest in the joint venture including producing wells and undeveloped acreage for approximately $65.0 million, subject to customary purchase price adjustments and the receipt of certain third-party consents. The effective date of the transaction will be January 1, 2014 and any amounts remaining under the drilling carry will be terminated upon closing of the acquisition. The transaction is expected to close in the first half of 2014.

Haynesville and Eagle Ford Acquisitions

On July 2, 2013, we entered into definitive agreements with Chesapeake to acquire producing and undeveloped oil and natural gas assets in the Haynesville and Eagle Ford shale formations. We closed the acquisition of the Haynesville assets on July 12, 2013 for a purchase price of $281.1 million, after final purchase price adjustments. The acquisition included certain producing wells and non-producing oil, natural gas and mineral leases located in our core Haynesville shale operating area in Caddo Parish and DeSoto Parish, Louisiana. These properties included Chesapeake's non-operated interests in 170 wells operated by EXCO on approximately 5,500 net acres, and operated interests in 11 producing wells on approximately 4,000 net acres. The acquisition added approximately 55 identified drilling locations in the Haynesville shale formation to our drilling inventory. BG Group elected not to exercise its preferential right to acquire a 50% interest in these assets.

We closed the acquisition of the Eagle Ford assets on July 31, 2013 for a purchase price of $661.8 million, after final purchase price adjustments. The acquisition included certain producing wells and non-producing oil, natural gas and mineral leases in the Eagle Ford shale in the counties of Zavala, Dimmit and Frio in South Texas. These properties initially included operated interests in 120 wells on approximately 53,500 net acres. The acquisition added approximately 300 identified locations to our drilling inventory. In connection with the acquisition of the Eagle Ford assets, we entered into a farm-out agreement with Chesapeake covering acreage adjacent to the acquired properties. Pursuant to the terms of the farm-out agreement, Chesapeake retains an overriding royalty interest in wells drilled on acreage covered by the farm-out agreement, with an option to convert the overriding royalty interest to a working interest at payout of the well.

We accounted for the acquisitions in accordance with FASB ASC Topic 805, *Business Combinations*. The following table presents a summary of the fair value of assets acquired and liabilities assumed as part of the Haynesville and Eagle Ford acquisitions based on the final settlement statements as of July 12, 2013 and July 31, 2013, respectively:

Purchase Price Allocation (in thousands):	**Haynesville Acquired Properties**	**Eagle Ford Acquired Properties**
Assets acquired:		
Unproved oil and natural gas properties	$ 2,319	$ 227,869
Proved developed and undeveloped oil and natural gas properties	282,918	437,616
Liabilities assumed:		
Accounts payable and accrued liabilities	—	(580)
Revenues and royalties payable	(3,526)	—
Asset retirement obligations	(610)	(3,060)
Total purchase price	$ 281,101	$ 661,845

We performed a valuation of the assets acquired and liabilities assumed as of the respective acquisition dates. A summary of the key inputs are as follows:

Oil and Natural Gas Properties - The fair value allocated to proved and unproved oil and natural gas properties was $285.2 million for the Haynesville assets and $665.5 million for the Eagle Ford assets. The fair value of oil and natural gas properties was determined based on a discounted cash flow model of the estimated reserves. The estimated quantities of reserves utilized assumptions based on our internal geological, engineering and financial data. We utilized NYMEX forward strip prices to value the reserves, then applied various discount rates depending on the classification of reserves and other risk characteristics.

Asset Retirement Obligations - The fair value allocated to asset retirement obligations was $0.6 million for the Haynesville assets and $3.1 million for the Eagle Ford assets. These asset retirement obligations represent the present value of the estimated amount to be incurred to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state laws. The fair value was determined based on a discounted cash flow model, which included assumptions of the estimated current abandonment costs, discount rate, inflation rate, and timing associated with the incurrence of these costs.

Revenues and royalties payable and accounts payable and accrued liabilities - The fair value was equivalent to the carrying amount because of their short-term nature. The revenues and royalties payable related to the Eagle Ford acquisition will be settled outside of the final settlement statement in the first quarter of 2014. We have accrued for the revenues and royalties payable as well as recorded a related receivable from Chesapeake based on our estimate of the expected settlement.

Pro forma results of operations - The following table reflects the unaudited pro forma results of operations as though the acquisition of the Chesapeake Properties had occurred on January 1, 2012:

	Year Ended December 31,	
(in thousands, except for per share data)	**2013**	**2012**
Oil and natural gas revenues	$ 784,628	$ 715,286
Net income (loss)	$ 38,663	$ (1,398,169)
Basic earnings (loss) per share	$ 0.18	$ (6.52)
Diluted earnings (loss) per share	$ 0.17	$ (6.52)

KKR Participation Agreement

In connection with closing the acquisition of the Eagle Ford assets, we entered into the KKR Participation Agreement and sold an undivided 50% interest in the undeveloped acreage we acquired for approximately $130.9 million, after final purchase price adjustments. Proceeds from the sale of properties under the KKR Participation Agreement were used to reduce outstanding borrowings under the EXCO Resources Credit Agreement. After giving effect to the KKR payment, the EXCO Resources Credit Agreement borrowing base and outstanding borrowings were reduced by $130.9 million.

The KKR Participation Agreement provides that EXCO and KKR will jointly fund future costs to develop the Eagle Ford assets. With respect to each well drilled, EXCO will assign half of its undivided 50% interest in such well to KKR such that KKR will fund and own 75% of each well drilled and EXCO will fund and own 25% of each well drilled. On a quarterly basis, EXCO and KKR will determine the development plan covering the following 12 months. EXCO will be required to offer to purchase KKR's 75% working interest in wells drilled that have been on production for one year. These offers will be made on a quarterly basis for groups of wells at a price defined in the KKR Participation Agreement, subject to specific well criteria and return hurdles. KKR is required to accept the offer if it exceeds the required return. We are required to make our first offer during the first quarter of 2015 for wells that have been on-line for approximately one year.

TGGT transaction

On November 15, 2013, EXCO and BG Group closed the conveyance of 100% of the equity interests in TGGT to Azure Midstream Holdings LLC ("Azure"). We received $240.2 million in net cash proceeds at the closing and an equity interest in Azure of approximately 4%. For further discussion see "Note 14. Equity investments".

2012 Acquisitions, divestitures 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.

2011 Acquisitions, divestitures 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 ("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).

Haynesville shale acquisition

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

TGGT incident

During 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.

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 instruments. 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 ASC 815, which requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. ASC 815 requires that changes in the derivative's fair value be recognized 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 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)	December 31, 2013	December 31, 2012
Derivative financial instruments - Current assets	$ 8,226	$ 49,500
Derivative financial instruments - Long-term assets	6,829	16,554
Derivative financial instruments - Current liabilities	(11,919)	(2,396)
Derivative financial instruments - Long-term liabilities	(9,671)	(26,369)
Net derivative financial instruments	$ (6,535)	$ 37,289

The Effect of Derivative Financial Instruments

	Year Ended December 31,		
(in thousands)	2013	2012	2011
Gain (loss) on derivative financial instruments	$ (320)	$ 66,133	$ 219,730

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 oil and natural gas derivative instruments are comprised of swap, basis 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. Basis swap contracts allow us to receive a fixed price differential between market indices for oil prices based on the delivery point. Our oil basis swaps typically have a positive differential to NYMEX West Texas Intermediate oil prices ("WTI"). Call options are financial contracts that give our trading counterparties the right, but not the obligation, to buy an agreed quantity of oil or 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. These transactions were conducted contemporaneously with a single counterparty and resulted in a net cashless transaction.

We place our derivative financial instruments with the financial institutions that are lenders under our respective credit agreements 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. We proportionately consolidate the derivative financial instruments entered into by the EXCO/HGI Partnership, however the contracts of the EXCO/HGI Partnership involve separate master netting agreements with their counterparties and we are not liable in the event of default.

The following table presents the volumes and fair value of our oil and natural gas derivative financial instruments (including our 25.5% proportionate interest in the EXCO/HGI Partnership's derivative financial instruments) as of December 31, 2013:

(in thousands, except prices)	Volume Mmbtu/ Bbl	Weighted average strike price per Mmbtu/Bbl	Fair value at December 31, 2013
Natural gas:			
Swaps:			
2014	84,060	$ 4.22	2,941
2015	28,288	4.31	4,742
Call options:			
2014	20,075	4.29	(4,581)
2015	20,075	4.29	(7,017)
Total natural gas			$ (3,915)
Oil:			
Swaps:			
2014	1,644	$ 95.03	(1,555)
2015	548	91.78	1,079
Basis Swaps			
2014	183	6.03	411
2015	91	6.10	242
Calls options:			
2014	365	100.00	(909)
2015	365	100.00	(1,888)
Total oil			$ (2,620)
Total oil and natural gas derivative financial instruments			$ (6,535)

At December 31, 2012, we had outstanding derivative contracts to mitigate our exposure to price volatility covering 216,263 Mmmbtu of natural gas and 1,095 Mbbls of oil. At December 31, 2013, the average forward NYMEX WTI oil prices per Bbl for the calendar years 2014 and 2015 were $96.14, and $88.75, respectively, the average forward NYMEX Louisiana Light Sweet ("LLS"), oil prices per barrel for the calendar years 2014 and 2015 were $99.90, and $92.18, respectively, and the average forward NYMEX Henry Hub natural gas prices per Mmbtu for the calendar years 2014 and 2015 were $4.17 and $4.14, respectively.

Our derivative financial instruments covered approximately 57% and 44% of production volumes for the years ended December 31, 2013 and 2012.

5. Fair value measurements

We value our derivatives and other financial instruments 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.

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 fair value of our derivative financial instruments 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. During the years ended December 31, 2013 and 2012 there were no changes in the fair value level classifications. The following table presents a summary of the estimated fair value of our derivative financial instruments as of December 31, 2013 and 2012.

	December 31, 2013			
(in thousands)	**Level 1**	**Level 2**	**Level 3**	**Total**
Oil and natural gas derivative financial instruments	$ —	$ (6,535)	$ —	$ (6,535)

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

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 or the credit-adjusted risk-free rate curve of the EXCO/HGI Partnership. 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 ("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. In addition, the credit-adjusted risk-free rate for the EXCO/HGI Partnership is based on the cost of debt 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, basis swaps and call option contracts, is discussed below.

Oil derivatives. Our oil derivatives are swap, basis swap and call option contracts for notional Bbls of oil at fixed (in the case of swap and basis swap contracts) or interval (in the case of call option contracts) NYMEX oil index 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 oil index prices, (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 NYMEX oil index prices.

Natural gas derivatives. Our natural gas derivatives are swap and call option contracts for notional Mmbtus of natural gas at posted price indexes, including NYMEX Henry Hub ("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 for natural gas swaps, (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 values of our borrowings under the revolving commitment of the EXCO Resources Credit Agreement and EXCO/HGI Partnership Credit Agreement approximate fair value, as these are subject to short-term floating interest rates that approximate the rates available to us for those periods.

The estimated fair values of our 7.5% senior unsecured notes due September 15, 2018 ("2018 Notes") and the term loan under the EXCO Resources Credit Agreement ("Term Loan"), at December 31, 2013 and December 31, 2012 are presented below. The estimated fair values of the 2018 Notes and the Term Loan have been calculated based on market quotes.

(in thousands)	December 31, 2013 Level 1	Level 2	Level 3	Total
2018 Notes	$ 714,000	$ —	$ —	$ 714,000
Term Loan	298,500	—	—	298,500

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

Other fair value measurements

We recorded an other than temporary impairment of $86.8 million to our investment in TGGT in 2013 as a result of the carrying value exceeding the fair value. We considered third-party offers in determining the fair value. The inputs used in determining the fair value as part of the impairment calculation are considered to be Level 2 within the fair value hierarchy. See further discussion of our investment in TGGT in "Note 14. Equity investments".

6. Debt

Our total debt is summarized as follows:

(in thousands)	December 31, 2013	December 31, 2012
Revolving credit facility under EXCO Resources Credit Agreement	$ 763,866	$ 1,107,500
Term Loan under EXCO Resources Credit Agreement	298,500	—
Unamortized discount on Term Loan	(2,780)	—
2018 Notes	750,000	750,000
Unamortized discount on 2018 Notes	(7,293)	(8,528)
Total debt excluding the EXCO/HGI Partnership	1,802,293	1,848,972
EXCO/HGI Partnership Credit Agreement	88,485	—
Total debt	1,890,778	1,848,972
Less amounts due within one year	31,866	—
Total debt due after one year	$ 1,858,912	$ 1,848,972

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

EXCO Resources Credit Agreement

On July 31, 2013, we amended and restated the EXCO Resources Credit Agreement which increased our borrowing base to $1.6 billion, including a $1.3 billion revolving commitment and a $300.0 million term loan commitment. The amendment to the EXCO Resources Credit Agreement included a $400.0 million asset sale requirement which was eliminated as a result of the repayment of outstanding borrowings in January 2014. The maturity date of the revolving commitment of the EXCO Resources Credit Agreement is July 31, 2018.

On August 19, 2013, the EXCO Resources Credit Agreement was amended to reflect a term loan that ranks pari passu in right of payment and of security with the revolving loans. The term loan has a maturity date of August 19, 2019 unless a permitted refinancing of the 2018 Notes does not occur prior to March 15, 2018, in which case the term loan will have a maturity date of July 31, 2018. We have scheduled principal payments on the term loan in the amount of $0.8 million due and payable on the last day of March, June, September and December of each year beginning on September 30, 2013. As of December 31, 2013, $298.5 million in principal was outstanding on the term loan. The unamortized discount on the term loan at December 31, 2013 was $2.8 million.

Proceeds from the sale of properties under the KKR Participation Agreement on July 31, 2013 and proceeds from the sale of our equity interest in TGGT on November 15, 2013 were used to reduce outstanding borrowings under the EXCO Resources Credit Agreement. After giving effect to these transactions, the EXCO Resources Credit Agreement borrowing base and outstanding borrowings were reduced by $371.1 million and our asset sale requirement was reduced to $28.9 million as of December 31, 2013. As discussed in "Note 17. Rights Offering", on January 17, 2014, we received proceeds of $272.9 million from the rights offering of our common stock ("Rights Offering"), which we used to pay down the remaining indebtedness related to the asset sale requirement as well as a portion of the indebtedness outstanding under the revolving commitment under the EXCO Resources Credit Agreement. Upon repayment of the asset sale requirement, the interest rate on the revolving commitment decreased by 100 basis points. After giving effect to the Rights Offering and the related transactions, the available borrowing base on the revolving commitment under the EXCO Resources Credit Agreement was $900.0 million with approximately $491.0 million of outstanding indebtedness and approximately $402.1 million of unused borrowing base, net of letters of credit.

As of December 31, 2013, the revolving commitment under the EXCO Resources Credit Agreement had an available borrowing base of approximately $928.9 million, with $763.9 million of outstanding indebtedness and $158.1 million of unused borrowing base, net of letters of credit.

Under the EXCO Resources Credit Agreement, the next borrowing base redetermination for the revolving commitment will occur in April 2014. Subsequent redeterminations will occur semi-annually with us and the lenders having the right to request interim unscheduled redeterminations in certain circumstances. The interest rate grid for the revolving commitment under the EXCO Resources Credit Agreement ranges from LIBOR plus 175 bps to 275 bps (or alternate base rate ("ABR") plus 75 bps to 175 bps), depending on our borrowing base usage. The interest rate grid was increased by 100 bps per annum until the asset sale requirement was eliminated in January 2014. On December 31, 2013, the one month LIBOR was 0.2%, which resulted in an interest rate of approximately 3.7% on the revolving commitment. The term loan bears interest at LIBOR, with a floor of 100 bps, plus 400 bps (or ABR plus 300 bps). The interest rate on the term loan was approximately 5.0% as of December 31, 2013.

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 to date. The repurchase of our common stock was prohibited until the asset sale requirement was eliminated in January 2014. There were no share repurchases during 2013, 2012 and 2011.

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, for any month during the first two years of the forthcoming five-year period, 90% of forecasted production from total Proved Reserves for any month during the third year of the forthcoming five-year period and 85% of forecasted production from total Proved Reserves for any month during the fourth and fifth years 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 a cumulative total of $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 revolving commitment, as defined in the EXCO Resources Credit Agreement, 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, 2013, 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.

The amendment to the EXCO Resources Credit Agreement also added that a breach of any financial covenants with respect to any term loans shall not be considered an event of default unless the aggregate revolving loans and letters of credit then outstanding is equal to or greater than $10.0 million and until the earlier of: (i) 90 days after the date such event of default arises, unless waived by the revolving lenders having a revolving exposure representing at least 66 2/3% of the aggregate revolving loans, letters of credit and unused commitments prior to such 90th day, and (ii) the date on which the administrative agent or such revolving lenders cause such indebtedness to become due prior to July 31, 2018.

While we believe our existing capital resources, including our cash flow from operations and borrowing capacity under the EXCO Resources Credit Agreement are sufficient to conduct our operations through 2014 and into 2015, there are certain risks arising from depressed oil and natural gas prices and declines in production volumes 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 the trailing 12 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 credit agreement. As a result, our ability to maintain compliance with this covenant may be negatively impacted when oil and/or natural gas prices remain depressed for an extended period of time.

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, our jointly-held equity investments with BG Group and the EXCO/HGI Partnership. 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, 2013, $750.0 million in principal was outstanding on the 2018 Notes. The unamortized discount on the 2018 Notes at December 31, 2013 was $7.3 million. Interest accrues at 7.5% and is payable 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.

EXCO/HGI Partnership Credit Agreement

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. The EXCO/HGI Partnership entered into the First Amendment to the EXCO/HGI Partnership Credit Agreement on March 5, 2013, which increased the borrowing base to $470.0 million as a result of the acquisition of the shallow Cotton Valley assets from an affiliate of BG Group. The borrowing base is redetermined semi-annually, with the EXCO/HGI Partnership and the lenders having the right to request interim unscheduled redeterminations in certain circumstances. On December 3, 2013, the borrowing base was reduced to $400.0 million in conjunction with the semi-annual redetermination. The EXCO/HGI Partnership Credit Agreement matures on February 14, 2018.

Borrowings under the EXCO/HGI Partnership Credit Agreement are secured by properties owned by 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 or the 2018 Notes. As of December 31, 2013, $347.0 million was drawn under this agreement and our proportionate share of the obligation was $88.5 million. 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. On December 31, 2013, the interest rate on the outstanding borrowings was approximately 2.7%.

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. 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 years of the forthcoming five year period.

As of December 31, 2013, the EXCO/HGI Partnership was in compliance with the financial covenants contained in the EXCO/HGI Partnership Credit Agreement, which require that it:

- maintain a consolidated current ratio (as defined in the agreement) of at least 1.0 to1.0 as of the end of any fiscal quarter; and
- not permit the ratio of consolidated funded indebtedness (as defined in the agreement) to consolidated EBITDAX (as defined in the agreement) to be greater than 4.5 to1.0 at the end of any fiscal quarter.

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

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 $5.9 million, $6.8 million and $8.2 million for the years ended December 31, 2013, 2012 and 2011, respectively. We have also entered into various drilling rig contracts primarily to develop our Haynesville and Eagle Ford shale assets. These contracts are short-term in nature and are dependent on our planned drilling program.

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 2013, our firm transportation agreements covered an average of 1.1 Bcf per day through 2016, with average annual minimum gathering and transportation expenses of approximately $135.3 million per year. For the years 2017 through 2021, our firm transportation agreements range from covering an average of 1.0 Bcf per day in 2017 and trend down to 333 Mmcf per day in 2021, with average annual minimum gathering and transportation expenses ranging from approximately $132.9 million per year in 2017 and trending down to $40.7 million in 2021. These volumes and expenses represent our gross commitments under these contracts and a portion of these costs will be incurred by other working interest owners. Our other fixed commitments primarily consist of completion service contracts and marketing contracts in which we are obligated to pay the buyer a fee if we fail to deliver minimum quantities of natural gas.

Our future minimum obligations under these agreements for office and equipment leases, drilling rig contracts, firm transportation services and other fixed commitments at December 31, 2013 are presented in the table below. 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
2014	$ 136,376	$ 14,532	$ 40,286	$ 8,055	$ 199,249
2015	136,040	17,299	—	4,978	158,317
2016	133,429	13,226	—	1,558	148,213
2017	132,860	5,428	—	140	138,428
2018	129,140	3,197	—	—	132,337
Thereafter	190,678	5,929	—	—	196,607
Total	$ 858,523	$ 59,611	$ 40,286	$ 14,731	$ 973,151

In the ordinary course of business, we are periodically a party to lawsuits. From time to time, oil and natural gas producers, including EXCO, have been named in various lawsuits alleging underpayment of royalties and the allocation of production costs in connection with oil, 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

We sponsor a 401(k) plan for our employees and matched 100% of employee contributions. Our matching contributions were \$8.8 million, \$9.4 million and \$9.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

10. Earnings per share

We account for earnings per share in accordance with ASC 260-10 which requires companies to present two calculations of EPS: basic and diluted. Basic EPS for the years ended December 31, 2013, 2012 and 2011 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, 2013, 2012 and 2011 is 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 stock options, restricted stock awards and subscription rights, whether exercisable or not. The computation of diluted EPS excluded 55,524,191, 17,242,306 and 7,251,289 antidilutive common share equivalents for the years ended December 31, 2013, 2012 and 2011, respectively. The antidilutive common share equivalents for the year ended December 31, 2013 primarily consisted of subscription rights outstanding as well as out-of-the-money stock options. The antidilutive common share equivalents for the years ended December 31, 2012 and 2011 primarily related to out-of-the-money stock options.

The following table presents the basic and diluted earnings (loss) per share computations for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
(in thousands, except per share data)	**2013**	**2012**	**2011**
Basic net income (loss) per common share:			
Net income (loss)	\$ 22,204	\$ (1,393,285)	\$ 22,596
Weighted average common shares outstanding	215,011	214,321	213,908
Net income (loss) per basic common share	\$ 0.10	\$ (6.50)	\$ 0.11
Diluted net income (loss) per common share:			
Net income (loss)	\$ 22,204	\$ (1,393,285)	\$ 22,596
Weighted average common shares outstanding	215,011	214,321	213,908
Dilutive effect of:			
Stock options	—	—	2,797
Restricted shares	420	—	—
Subscription rights	15,481	—	—
Weighted average common shares and common share equivalents outstanding	230,912	214,321	216,705
Net income (loss) per diluted common share	\$ 0.10	\$ (6.50)	\$ 0.10

11. Stock options and awards

Description of plan

As of December 31, 2013 and 2012, there were 21,118,292 and 2,682,249 shares, respectively, available for issuance under the 2005 Incentive Plan. Under the plan we grant both options and restricted stock. Effective June 11, 2013, our shareholders voted to increase the total shares authorized for issuance under the 2005 Incentive Plan from 28,500,000 to 45,500,000 shares, increasing the number of shares available for grant by 17,000,000. 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, 2.1 shares for awards granted after October 6, 2011 and 1.74 shares for awards granted after June 11, 2013. 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, 2013 was $23.6 million. Of this amount, $7.0 million related to unvested options will be recognized over a weighted average period of 2.5 years and $16.6 million related to unvested restricted stock awards will be recognized over a weighted average period of 2.1 years.

The following is a reconciliation of our share-based compensation expense for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
(in thousands)	**2013**	**2012**	**2011**
General and administrative expense	$ 10,748	$ 8,926	$ 10,872
Lease operating expense	—	—	140
Total share-based compensation expense	10,748	8,926	11,012
Share-based compensation capitalized	7,288	7,513	6,406
Total share-based compensation	$ 18,036	$ 16,439	$ 17,418

The total tax benefit attributable to our share-based compensation for the year ended December 31, 2011 was $1.2 million. We did not recognize a tax benefit attributable to our share-based compensation for the years ended December 31, 2013 and 2012.

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 5.1 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, 2013, 2012 and 2011:

	Stock Options	Weighted average exercise price per share	Weighted average remaining terms (in years)	Aggregate intrinsic value
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		
Granted	2,886,500	7.48		
Forfeitures	4,969,877	11.32		
Exercised	220,675	7.66		
Options outstanding at				
December 31, 2013	11,711,743	$ 12.69	5.1	$ —
Options exercisable at				
December 31, 2013	9,839,918	$ 13.64	4.3	$ —

The weighted average fair value of stock options on the date of the grant during the years ended December 31, 2013, 2012 and 2011 was $3.53, $3.96 and $5.92, respectively. The total intrinsic value of stock options exercised for the years ended December 31, 2013, 2012 and 2011 was $0.2 million, $0.1 million and $6.0 million, respectively.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model. The exercise price of the options is based on 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, for the years ended December 31:

	2013	2012	2011
Expected life	3.8 to 7.5 years	3.8 to 7.5 years	3.8 to 7.5 years
Risk-free rate of return	0.48 - 2.49 %	0.56 - 1.64 %	0.67 - 3.09 %
Volatility	49.47 - 59.86 %	57.34 - 60.24 %	55.77 - 72.83 %
Dividend yield	2.27 - 3.87 %	0.52 - 1.92 %	0.77 - 1.15 %

Expected life was determined based on EXCO's exercise history. 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. Dividend yield was determined based on EXCO's expected annual dividend and the market price of our common stock on the date of grant.

Service-based restricted stock awards

Our service-based restricted stock awards are valued at the closing price of our stock on the date of grant and vest over a range of three to five years. A summary of our service-based restricted stock activity for the years ended December 31, 2013, 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
Granted	556,700	7.15
Vested	(832,706)	10.47
Forfeited	(602,045)	9.84
Non-vested shares outstanding at December 31, 2013	1,928,314	$ 9.26

Market-based restricted stock awards

On August 13, 2013, EXCO's officers were granted a market-based restricted stock award for shares of common stock. The total number of units granted was 736,000 of which 368,000 will be vested following any 30 consecutive trading days in which the company's common stock equals or exceeds $10.00 per share and 368,000 units will be vested following any 30 consecutive trading days in which the company's common stock equals or exceeds $15.00 per share. Shares vest over a two year period and are subject to other vesting provisions depending on when the attainment date occurs.

The grant date fair value of our market-based restricted stock awards was determined using a Monte Carlo model which uses company-specific inputs to generate different stock price paths. A summary of our market-based restricted stock activity for the year ended December 31, 2013 is as follows:

	Shares	Weighted average grant date fair value per share
Non-vested shares outstanding at December 31, 2012	—	$ —
Granted	736,000	6.36
Vested	—	—
Forfeited	(261,400)	6.36
Non-vested shares outstanding at December 31, 2013	474,600	$ 6.36

12. Income taxes

The income tax provision attributable to our income (loss) before income taxes for the years ended December 31, 2013, 2012 and 2011, consisted of the following:

(in thousands)	Year ended December 31, 2013	2012	2011
Current:			
Federal	$ —	$ —	$ —
State	—	—	—
Total current income tax (benefit)	$ —	$ —	$ —
Deferred:			
Federal	$ 25,626	$ (485,543)	$ 10,111
State	3,239	(59,406)	1,554
Valuation allowance	(28,865)	544,949	(11,665)
Total deferred income tax (benefit)	—	—	—
Total income tax (benefit)	$ —	$ —	$ —

We have net operating loss carryforwards ("NOLs") for United States income tax purposes that have been generated from our operations. Our NOLs are scheduled to expire if not utilized between 2027 and 2033. NOL and alternative minimum tax credits available for utilization as of December 31, 2013 were approximately $1.9 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, 2013	December 31, 2012
Current deferred tax asset (liabilities):		
Derivative financial instruments	$ —	$ —
Other	5,332	152
Valuation allowance	(5,332)	(152)
Net current deferred tax assets (liabilities)	—	—
Non-current deferred tax assets:		
Net operating loss and AMT credits carryforwards	$ 737,399	$ 604,437
Share-based compensation	16,060	11,173
Oil and natural gas properties, gathering assets, and equipment	47,491	398,350
Goodwill	9,812	6,291
Derivative financial instruments	2,102	—
Investment in partnerships	73,328	—
Other	85	85
Total non-current deferred tax assets	886,277	1,020,336
Valuation allowance	(886,277)	(919,986)
Total non-current deferred tax assets	—	100,350
Non-current deferred tax liabilities:		
Oil and natural gas properties, gathering assets, and equipment	$ —	$ (4,931)
Investments in partnerships	—	(80,825)
Derivative financial instruments	—	(14,594)
Total non-current deferred tax liabilities	—	(100,350)
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, 2013, 2012 and 2011 is presented in the following table:

(in thousands)	Year Ended December 31, 2013	2012	2011
Federal income taxes (benefit) provision at statutory rate of 35%	$ 7,772	$ (487,649)	$ 7,909
Increases (reductions) resulting from:			
Goodwill	16,382	—	—
Adjustments to the valuation allowance	(28,865)	544,949	(11,665)
Non-deductible compensation	1,328	1,893	1,760
State taxes net of federal benefit	3,239	(59,406)	1,554
Other	144	213	442
Total income tax provision	$ —	$ —	$ —

During 2013, 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 2013.

During 2012, our net loss was greatly impacted by the ceiling test impairments and the recognized valuation allowance almost completely offset the impairments. 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.

We adopted the provisions of ASC 740-10 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, 2013, 2012 and 2011, 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 2005. The Company was notified during the year ended December 31, 2013 that the corporate tax return for the year ended December 31, 2011 would be examined by the Internal Revenue Service. In addition, two pass-through entities in which the Company owns an interest will also be examined for the year ended December 31, 2010.

13. Related party transactions

TGGT and OPCO

TGGT provided us with gathering, treating and well connection services in the ordinary course of business as well as purchased natural gas from us in certain areas. Also, we previously provided administrative services to TGGT for which we were reimbursed. On November 15, 2013, we sold our equity investment in TGGT to Azure. See further discussion of this transaction in "Note 14. Equity Investments". Transactions with Azure after November 15, 2013 are not included in the tables below as Azure no longer meets the disclosure requirements as a related party. OPCO serves as the operator of our wells in the Appalachia JV. There are service agreements between us and OPCO whereby we provide administrative and technical services for which we are reimbursed.

For the years ended December 31, 2013, 2012 and 2011 these transactions included the following:

(in thousands)	Year Ended December 31, 2013 TGGT	2013 OPCO	2012 TGGT	2012 OPCO	2011 TGGT	2011 OPCO
Amounts paid:						
Gathering, treating and well connection fees (1)	$ 160,167	$ —	$ 218,902	$ —	$ 199,449	$ —
Advances to operator	—	28,378	—	76,729	—	69,111
Total	$ 160,167	$ 28,378	$ 218,902	$ 76,729	$ 199,449	$ 69,111
Amounts received:						
Natural gas purchases	$ 7,251	$ —	$ 15,340	$ —	$ 27,948	$ —
General and administrative services	18,413	43,632	18,258	52,206	15,730	47,337
Purchase of gathering and other assets	—	—	—	—	3,422	—
Other	52	—	1,905	—	2,147	—
Total	$ 25,716	$ 43,632	$ 35,503	$ 52,206	$ 49,247	$ 47,337

(1) Represents the gross billings from TGGT.

As of December 31, 2013 and 2012, the amounts owed under the service agreements were as follows:

(in thousands)	December 31, 2013 OPCO	December 31, 2012 TGGT	December 31, 2012 OPCO
Amounts due to EXCO	$ 2,283	$ 2,483	$ 2,956
Amounts due from EXCO (1)	—	12,540	—

(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 recorded 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 related party transactions

As discussed in "Note 6. Debt", the EXCO Resources Credit Agreement was amended to reflect a term loan on August 19, 2013. Investment accounts managed by Invesco Advisers, Inc. are lenders under the term loan. Invesco Advisers, Inc. is an indirect owner of WL Ross & Co. LLC. Wilbur L. Ross, Jr., the Chairman and Chief Executive Officer at WL Ross & Co. LLC, serves on EXCO's board of directors. Invesco Advisers, Inc. holds approximately 10% of total borrowings under the term loan and does not act as an administrative agent or serve in any other administrative capacity to the EXCO Resources Credit Agreement. After giving effect to the closing of the Rights Offering and related private placement, as discussed in "Note 17. Rights Offering", investment entities managed by WL Ross & Co. LLC beneficially own approximately 18.7% of EXCO's outstanding shares of common stock.

14. Equity investments

We hold equity investments in entities which are described below.

- 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. We use the equity method of accounting for our equity investment in OPCO.
- We own a 50% interest in the Appalachia Midstream JV, which holds interests in midstream assets in the Marcellus shale. We use the equity method of accounting for our equity investment in Appalachia Midstream JV.
- We own a 50% interest in an entity that manages certain surface acreage which is accounted for by the equity method of accounting.
- We own approximately 4% of the equity interests in Azure which holds interests in midstream assets in East Texas and North Louisiana. We use the cost method of accounting for our equity investment in Azure. We previously

owned a 50% interest in TGGT, which held interests in midstream assets in East Texas and North Louisiana. We sold our equity investment in TGGT to Azure on November 15, 2013, which is described below.

On November 15, 2013, EXCO and BG Group closed the conveyance of 100% of the equity interests in TGGT to Azure for an aggregate sales price of approximately $910.0 million, of which approximately $876.5 million was paid in cash and the remaining portion was paid in the form of an equity interest in Azure, which was split equally between EXCO and BG Group. The equity interest issued to EXCO is approximately 4% of the total outstanding equity interests of Azure as of the closing date. EXCO and BG Group were also granted an option for a period of one year to acquire an additional equity interest in Azure equal to the equity interest issued at closing for approximately $16.8 million plus a premium that will increase over time.

After the repayment of TGGT's indebtedness as of the closing date, we received $240.2 million in net cash proceeds from Azure after final purchase price adjustments. We also incurred expenses of $3.6 million to third-parties in connection with the transaction which primarily consisted of commissions and financial advisory fees. We recorded an equity investment of $13.4 million, net of a discount for a control premium, in Azure which will be accounted for under the cost method of accounting. Investments accounted for by the cost method are tested for impairment if an impairment indicator is present.

At the closing of the agreement, EXCO and BG Group agreed to deliver to Azure's gathering systems an aggregate minimum volume commitment of 600,000 Mmbtu/day of natural gas production from the Holly and Shelby fields over a five year period. The minimum volume commitment may be satisfied with (i) production of EXCO, BG Group and each of their respective affiliates, (ii) production of joint venture partners of either EXCO, BG Group or their affiliates, and (iii) production of non-operating working interest owners to the extent EXCO, BG Group, and each of their respective affiliates or its joint venture partner controls such production. If there is a shortfall to the minimum volume commitment in any year, then EXCO and BG Group are severally responsible for paying to Azure a shortfall payment in an amount equal to the amount of the shortfall (calculated on an annualized basis) times $0.40 per Mmbtu. EXCO and BG Group are entitled to credit 25% of any production volumes delivered in excess of the minimum volume commitment during any year to the subsequent year.

We used all of the cash proceeds from the sale of TGGT to reduce outstanding borrowings under the asset sale requirement of the EXCO Resources Credit Agreement, which also resulted in a corresponding reduction in our borrowing base. We recorded an other than temporary impairment of $86.8 million to our investment in TGGT during 2013 as a result of the carrying value exceeding the fair value.

The following tables present summarized consolidated financial information of our equity method investments and a reconciliation of our investment to our proportionate 50% interest. Our equity investment in Azure is not included in the tables below as it is accounted for under the cost method of accounting.

(in thousands)	**December 31, 2013**	**December 31, 2012**
Assets		
Total current assets	$ 78,437	$ 151,098
Property and equipment, net	73,451	1,228,231
Other assets	1,041	6,408
Total assets	$ 152,929	$ 1,385,737
Liabilities and members' equity		
Total current liabilities	$ 63,043	$ 120,408
Total long term liabilities	258	492,071
Members' equity:		
Total members' equity	89,628	773,258
Total liabilities and members' equity	$ 152,929	$ 1,385,737

(in thousands)	Year Ended December 31, 2013	2012	2011
Revenues:			
Oil and natural gas	$ 776	$ 456	$ 524
Midstream	188,882	253,586	242,366
Total revenues	189,658	254,042	242,890
Costs and expenses:			
Oil and natural gas production	289	234	55
Midstream operating	52,086	69,682	108,116
Impairment of oil and natural gas properties	—	1,230	1,445
Asset impairments, net of insurance recoveries	7,246	50,771	9,688
General and administrative	12,638	24,593	19,597
Depletion, depreciation and amortization	40,409	40,570	28,482
Other expenses	12,961	13,049	13,211
Total costs and expenses	125,629	200,129	180,594
Income before income taxes	64,029	53,913	62,296
Income tax expense	361	425	636
Net income	$ 63,668	$ 53,488	$ 61,660
EXCO’s share of equity income before amortization and impairment	$ 31,834	$ 26,744	$ 30,830
Amortization of the difference in the historical basis of our contribution	1,670	1,876	1,876
Impairment of equity investment	(86,784)	—	—
EXCO’s share of equity income (loss) after amortization and impairment	$ (53,280)	$ 28,620	$ 32,706

(in thousands)	December 31, 2013	December 31, 2012
Equity method investments	$ 44,162	$ 347,008
Basis adjustment (1)	1,618	45,755
Cumulative amortization of basis adjustment (2)	(966)	(6,134)
EXCO’s 50% interest in equity method investments	$ 44,814	$ 386,629

(1) Our equity in TGGT and OPCO, at inception, exceeded the book value of our investments by an aggregate of $45.8 million, comprised of an aggregate $57.2 million difference in the historical basis of our contribution and the fair value of BG Group’s contribution, offset by $11.4 million of goodwill included in our investment in TGGT. The basis difference in our investment in TGGT was eliminated as a result of the sale during 2013. The December 31, 2013 basis adjustment reflects OPCO's difference in historical basis.

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

15. Dividends

On November 21, 2013, our board of directors approved a cash dividend of $0.05 per share for the fourth quarter of 2013. The total cash dividend was $10.9 million, of which $10.8 million was paid on December 16, 2013 to holders of record on December 2, 2013 and the remainder was accrued to be paid to holders of restricted shares upon vesting. Total dividends paid to our shareholders in 2013, 2012 and 2011 were $43.2 million, $34.4 million, and $34.2 million, respectively.

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.

16. 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 repurchase of our common stock was prohibited until the asset sale requirement of the EXCO Resources Credit Agreement was eliminated in January 2014. As of December 31, 2013, we have repurchased a total of 539,221 shares for $7.5 million at an average price of $13.87 per share. There were no share repurchases during 2013, 2012 or 2011.

17. Rights Offering

On December 19, 2013, the Company granted subscription rights to holders of common stock which entitled the holder to purchase 0.25 of a share of our common stock for each share of common stock owned by such holders. Each subscription right entitled the holder to a basic subscription right and an over-subscription privilege. The basic subscription right entitled the holder to purchase 0.25 of a share of the Company's common stock at a subscription price equal to $5.00 per share of common stock. The over-subscription privilege entitled the holders who exercised their basic subscription rights in full (including in respect of subscription rights purchased from others) to purchase any or all shares of common stock that other rights holders do not purchase through the purchase of their basic subscription rights at a subscription price equal to $5.00 per share of common stock. The subscription rights expired if they were not exercised by January 9, 2014.

The Company entered into two investment agreements ("Investment Agreements") in connection with the Rights Offering, each dated as of December 17, 2013, one with certain affiliates of WL Ross and one with Hamblin Watsa pursuant to which, subject to the terms and conditions thereof, each of them has severally agreed to subscribe for and purchase, in a private placement, its respective pro rata portion of shares under the basic subscription right and all unsubscribed shares under the over-subscription privilege subject to pro rata allocation among the subscription rights holders who have elected to exercise their over-subscription privilege.

The Rights Offering and related transactions under the Investment Agreements closed on January 17, 2014 which resulted in the issuance of 54,574,734 shares for proceeds of $272.9 million. We used the proceeds to pay indebtedness under the EXCO Resources Credit Agreement which is further discussed in "Note 6. Debt". WL Ross and Hamblin Watsa purchased 19,599,973 and 6,726,712 shares, respectively, pursuant to their basic subscription rights and the over-subscription privilege. After giving effect to the Rights Offering, WL Ross and Hamblin Watsa owned 18.7% and 6.4%, respectively of the Company's outstanding common shares as of January 17, 2014.

18. Condensed consolidating financial statements

As of December 31, 2013, the majority of EXCO's subsidiaries were guarantors under the EXCO Resources Credit Agreement and the indenture governing the 2018 Notes. All of our non-guarantor subsidiaries were 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, 2013 our equity method investment in OPCO represented $12.9 million of equity method investments and contributed $4.7 million of equity method losses.

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 are 100% 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;
- 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 for the disclosures within this footnote. 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, 2013

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 81,840	$ (35,892)	$ 4,535	$ —	$ 50,483
Restricted cash	—	20,570	—	—	20,570
Other current assets	22,533	206,708	5,560	—	234,801
Total current assets	104,373	191,386	10,095	—	305,854
Equity investments	—	—	57,562	—	57,562
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties and development costs not being amortized	6,758	415,290	3,259	—	425,307
Proved developed and undeveloped oil and natural gas properties	337,972	3,097,335	118,903	—	3,554,210
Accumulated depletion	(330,086)	(1,840,332)	(13,046)	—	(2,183,464)
Oil and natural gas properties, net	14,644	1,672,293	109,116	—	1,796,053
Gathering, office, field and other equipment, net	3,479	24,612	22,248	—	50,339
Investments in and advances to affiliates, net	1,834,197	—	—	(1,834,197)	—
Deferred financing costs, net	27,771	—	1,036	—	28,807
Derivative financial instruments	6,829	—	—	—	6,829
Goodwill	13,293	149,862	—	—	163,155
Other assets	2	27	—	—	29
Total assets	$ 2,004,588	$ 2,038,180	$ 200,057	$ (1,834,197)	$ 2,408,628
Liabilities and shareholders' equity					
Current liabilities	$ 76,174	$ 264,485	$ 8,511	$ —	$ 349,170
Long-term debt	1,770,427	—	88,485	—	1,858,912
Deferred income taxes	—	—	—	—	—
Other long-term liabilities	10,082	33,831	8,728	—	52,641
Payable to parent	—	2,230,108	35,777	(2,265,885)	—
Total shareholders' equity	147,905	(490,244)	58,556	431,688	147,905
Total liabilities and shareholders' equity	$ 2,004,588	$ 2,038,180	$ 200,057	$ (1,834,197)	$ 2,408,628

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
Gathering, office, field and other equipment, net	7,701	109,490	—	—	117,191
Investments in and advances to affiliates, net	1,622,731	—	—	(1,622,731)	—
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	$ 2,070,082	$ 1,529,373	$ 347,008	$ (1,622,731)	$ 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	—	(2,172,526)	—
Total shareholders' equity	149,393	(896,803)	347,008	549,795	149,393
Total liabilities and shareholders' equity	$ 2,070,082	$ 1,529,373	$ 347,008	$ (1,622,731)	$ 2,323,732

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the year ended December 31, 2013

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 9,136	$ 582,158	$ 43,015	$ —	$ 634,309
Costs and expenses:					
Oil and natural gas production	2,440	63,716	17,092	—	83,248
Gathering and transportation	—	97,166	3,479	—	100,645
Depletion, depreciation and amortization	5,917	225,499	14,359	—	245,775
Impairment of oil and natural gas properties	—	108,546	—	—	108,546
Accretion of discount on asset retirement obligations	63	1,881	570	—	2,514
General and administrative	23,125	66,558	2,195	—	91,878
Gain on divestitures and other operating items	(25,950)	(151,549)	(19)	—	(177,518)
Total costs and expenses	5,595	411,817	37,676	—	455,088
Operating income (loss)	3,541	170,341	5,339	—	179,221
Other income (expense):					
Interest expense, net	(99,815)	—	(2,774)	—	(102,589)
Gain (loss) on derivative financial instruments	1,439	(177)	(1,582)	—	(320)
Other income	(1,068)	229	11	—	(828)
Equity loss	—	—	(53,280)	—	(53,280)
Net earnings from consolidated subsidiaries	118,107	—	—	(118,107)	—
Total other income (expense)	18,663	52	(57,625)	(118,107)	(157,017)
Income (loss) before income taxes	22,204	170,393	(52,286)	(118,107)	22,204
Income tax expense	—	—	—	—	—
Net income (loss)	$ 22,204	$ 170,393	$ (52,286)	$ (118,107)	$ 22,204

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
Depletion, depreciation and amortization	7,767	295,389	—	—	303,156
Impairment 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, net	(73,489)	(3)	—	—	(73,492)
Gain on derivative financial instruments	62,812	3,321	—	—	66,133
Other income	238	731	—	—	969
Equity income	—	—	28,620	—	28,620
Net loss from consolidated 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
Impairment 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:					
Interest expense, net	(59,764)	(1,259)	—	—	(61,023)
Gain on derivative financial instruments	190,043	29,687	—	—	219,730
Other income	316	472	—	—	788
Equity income	—	—	32,706	—	32,706
Net loss from consolidated subsidiaries	(95,419)	—	—	95,419	—
Total other income	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 CASH FLOWS

For the year ended December 31, 2013

(in thousands)	Resources	Guarantor Subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by (used in) operating activities	$ (32,678)	$ 365,770	$ 17,542	$ —	$ 350,634
Investing Activities:					
Additions to oil and natural gas properties, gathering assets and equipment and property acquisitions	(15,767)	(1,242,667)	(38,818)	—	(1,297,252)
Restricted cash	—	49,515	—	—	49,515
Equity method investments	—	236,289	—	—	236,289
Proceeds from disposition of property and equipment	244,500	505,128	—	—	749,628
Distributions received from EXCO/HGI Partnership	3,825	—	—	(3,825)	—
Net changes in advances to joint ventures	—	10,645	—	—	10,645
Advances/investments with affiliates	(59,575)	59,575	—	—	—
Other	(1,303)	—	—	—	(1,303)
Net cash provided by (used in) investing activities	171,680	(381,515)	(38,818)	(3,825)	(252,478)
Financing Activities:					
Borrowings under credit agreements	967,766	—	36,757	—	1,004,523
Repayments under credit agreements	(1,015,900)	—	(6,885)	—	(1,022,785)
Proceeds from issuance of common stock	1,712	—	—	—	1,712
Payment of common stock dividends	(43,214)	—	—	—	(43,214)
EXCO/HGI Partnership cash distribution	—	—	(3,825)	3,825	—
Deferred financing costs and other	(33,317)	—	(236)	—	(33,553)
Net cash provided by (used in) financing activities	(122,953)	—	25,811	3,825	(93,317)
Net increase (decrease) in cash	16,049	(15,745)	4,535	—	4,839
Cash at beginning of period	65,791	(20,147)	—	—	45,644
Cash at end of period	$ 81,840	$ (35,892)	$ 4,535	$ —	$ 50,483

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 assets and equipment and property acquisitions	(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
Net changes in advances to joint ventures	—	851	—	—	851
Advances/investments with affiliates	(59,126)	59,126	—	—	—
Net cash used in investing activities	(120,971)	(306,123)	—	—	(427,094)
Financing Activities:					
Borrowings under credit agreements	53,000	—	—	—	53,000
Repayments under credit agreements	(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 assets and equipment	(63,089)	(1,670,029)	(4,253)	—	(1,737,371)
Restricted cash	—	5,792	—	—	5,792
Equity method investments	—	111,171	—	—	111,171
Proceeds from disposition of property and equipment	3,129	446,554	—	—	449,683
Deposit on acquisitions	—	464,151	—	—	464,151
Net changes in advances to joint ventures	—	(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 credit agreements	706,000	—	—	—	706,000
Repayments under the credit agreements	(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

19. Quarterly financial data (unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2013 and 2012:

	Quarter			
(in thousands, except per share amounts)	1st	2nd	3rd	4th
2013				
Oil and natural gas revenues	$ 138,223	$ 150,332	$ 165,314	$ 180,440
Operating income (loss) (1)	209,075	33,883	15,594	(79,331)
Net income (loss) (2) (3)	$ 158,120	$ 85,598	$ (98,651)	$ (122,863)
Basic earnings (loss) per share:				
Net income (loss)	$ 0.74	$ 0.40	$ (0.46)	$ (0.57)
Weighted average shares	214,784	214,788	215,056	215,410
Diluted earnings (loss) per share:				
Net income (loss)	$ 0.74	$ 0.40	$ (0.46)	$ (0.57)
Weighted average shares	214,861	216,023	215,056	215,410
2012				
Oil and natural gas revenues	$ 134,848	$ 117,978	$ 141,621	$ 152,162
Operating loss (4)	(311,087)	(476,036)	(321,021)	(307,371)
Net loss	$ (281,649)	$ (496,433)	$ (346,174)	$ (269,029)
Basic loss per share:				
Net loss	$ (1.32)	$ (2.32)	$ (1.62)	$ (1.25)
Weighted average shares	214,145	214,164	214,301	214,672
Diluted loss per share:				
Net loss	$ (1.32)	$ (2.32)	$ (1.62)	$ (1.25)
Weighted average shares	214,145	214,164	214,301	214,672

(1) Operating income (loss) for the first quarter and the fourth quarter of 2013 includes $10.7 million and $97.8 million, respectively, of impairments of oil and natural gas properties. See "Note 2. Summary of significant accounting policies" for further discussion.

(2) Net income (loss) for the third quarter of 2013 includes a $91.5 million impairment to our investment in TGGT as a result of the carrying value exceeding the fair value. The impairment was reduced by $4.7 million in the fourth quarter of 2013 to $86.8 million as a result of final closing adjustments, fees and transaction expenses related to the sale of our equity investment in TGGT. See "Note 14. Equity investments" for further discussion.

(3) Net income (loss) for the first quarter of 2013 includes a gain of $187.0 million from our contribution of oil and natural gas properties to the EXCO/HGI Partnership. See "Note 3. Acquisitions, divestitures and other significant events" for further discussion.

(4) Operating loss for the first quarter, second quarter, third quarter and fourth quarter of 2012 includes $275.9 million, $428.8 million, $318.0 million and $324.0 million, respectively, of impairments of oil and natural gas properties. See "Note 2. Summary of significant accounting policies" for further discussion.

20. 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, 2013, 2012 and 2011 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
2013:		
Proved property acquisition costs	$	754,370
Unproved property acquisition costs		232,020
Total property acquisition costs (1)		986,390
Development		231,447
Exploration costs (2)		38,579
Lease acquisitions and other		14,835
Capitalized asset retirement costs		514
Depletion per Boe	$	8.82
Depletion per Mcfe	$	1.47
2012:		
Proved property acquisition costs	$	—
Unproved property acquisition costs		3,349
Total property acquisition costs		3,349
Development		346,017
Exploration costs (3)		57,325
Lease acquisitions and other (4)		44,546
Capitalized asset retirement costs		971
Depletion per Boe	$	9.11
Depletion per Mcfe	$	1.52
2011:		
Proved property acquisition costs	$	136,295
Unproved property acquisition costs		260,076
Total property acquisition costs (5)		396,371
Development		593,331
Exploration costs (6)		262,120
Lease acquisitions and other (7)		31,466
Capitalized asset retirement costs		3,765
Depletion per Boe	$	11.24
Depletion per Mcfe	$	1.87

(1) Acquisition costs in 2013 include the Eagle Ford acquisition, Haynesville acquisition and our proportionate share of the EXCO/HGI Partnership acquisition of shallow Cotton Valley assets.

(2) Exploration costs in 2013 include approximately $29.2 million in the Eagle Ford shale and approximately $9.4 million in the Marcellus shale.

(3) Exploration costs in 2012 include approximately $40.1 million in the Haynesville shale, and approximately $17.2 million in the Marcellus shale.

(4) Lease acquisition costs in 2012 are net of acreage reimbursements from BG Group totaling $2.1 million.

(5) Acquisition costs in 2011, net of BG Group reimbursements of $359.1 million, include the Chief Transaction, Appalachia Transaction and the Haynesville Shale Acquisition.

(6) 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.

(7) Lease acquisition costs in 2011 are net of acreage reimbursements from BG Group totaling $31.9 million.

We retain independent engineering firms to prepare or audit 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) (13)	Mmcfe
December 31, 2010 (1)	7,358	1,454,953		1,499,101
Purchase of reserves in place	—	62,489	—	62,489
Discoveries and extensions (2)	929	195,565	—	201,139
Revisions of previous estimates:				
Changes in price	100	(15,165)	—	(14,565)
Other factors (3)	(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 (4)	6,354	1,291,464	—	1,329,588
Purchase of reserves in place	—	—	—	—
Discoveries and extensions (5)	492	96,615	424	102,111
Revisions of previous estimates:				
Changes in price	(110)	(466,238)	—	(466,898)
Other factors (6)	(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 (7)	5,570	936,132	6,639	1,009,386
Purchase of reserves in place (8)	16,022	290,933	2,201	400,271
Discoveries and extensions (9)	5,960	46,834	513	85,672
Revisions of previous estimates:				
Changes in price	457	272,614	686	279,472
Other factors (10)	(3,219)	(106,695)	(741)	(130,455)
Sales of reserves in place (11)	(8,224)	(270,018)	(6,472)	(358,194)
Production	(1,188)	(153,321)	(243)	(161,907)
December 31, 2013 (12)	15,378	1,016,479	2,583	1,124,245

Estimated Quantities of Proved Developed and Proved Undeveloped Reserves

	Oil (Mbbls)	Natural Gas (Mmcf)	Natural Gas Liquids (Mbbls) (13)	Mmcfe
Proved developed:				
December 31, 2013	11,274	657,116	2,088	737,291
December 31, 2012	4,371	917,326	4,784	972,256
December 31, 2011	4,565	955,522	—	982,912
Proved undeveloped:				
December 31, 2013	4,104	359,363	495	386,954
December 31, 2012	1,199	18,806	1,855	37,130
December 31, 2011	1,789	335,942	—	346,676

(1) 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 $0.4 million, or 0.03%, of our consolidated Standardized Measure.

(2) 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 the Permian Basin.

(3) 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.

(4) 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 $0.6 million, or 0.04%, of our consolidated Standardized Measure.

(5) 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 the Permian Basin.

(6) 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.

(7) 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 $0.5 million, or 0.07% of our consolidated Standardized Measure.

(8) Purchases of reserves in place include 115,718 Mmcfe in the Eagle Ford shale, 259,991 Mmcfe in the Haynesville shale, and 24,558 Mmcfe for our proportionate share of the EXCO/HGI Partnership's acquisition of shallow Cotton Valley assets in East Texas/North Louisiana.

(9) New discoveries and extensions in 2013 included 36,501 Mmcfe in the Eagle Ford shale, 33,591 Mmcfe in the Marcellus shale, 10,211 Mmcfe in the Haynesville shale, 3,881 Mmcfe for conventional properties held by the EXCO/HGI Partnership in the Permian Basin, and 1,486 Mmcfe for shale properties in the Permian Basin.

(10) Total revisions due to Other factors were approximately 130,455 Mmcfe of downward revisions primarily in the Haynesville shale as a result of operational matters including scaling, liquid loading due to high-line pressure and the impact of drainage on new wells drilled directly offset to the unit wells.

(11) Sales of reserves in place included 327,608 Mmcfe as a result of our contribution of properties to the EXCO/HGI Partnership and 30,582 Mmcfe from the sale of undeveloped properties in the Eagle Ford in connection with the KKR Participation Agreement.

(12) The above reserves do not include our equity interest in OPCO, which represents 0.08% (910 Mmcfe) of our consolidated Proved Reserves at December 31, 2013 and a Standardized Measure of $0.8 million, or 0.06% of our consolidated Standardized Measure.

(13) Beginning in 2012, we began reporting our NGLs separately. In 2011, 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, the information presented below should not be viewed as an estimate of the fair value of our oil and natural gas properties, nor should it be indicative of any trends.

(in thousands)		Amount
Year ended December 31, 2013:		
Future cash inflows	$	5,176,030
Future production costs		2,207,230
Future development costs		904,116
Future income taxes		—
Future net cash flows		2,064,684
Discount of future net cash flows at 10% per annum		812,411
Standardized measure of discounted future net cash flows	$	1,252,273
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

During recent years, prices paid for oil and natural gas have fluctuated significantly. The reference prices at December 31, 2013, 2012 and 2011 used in the above table, were $96.78, $94.71 and $96.19 per Bbl of oil, respectively, and $3.67, $2.76 and $4.12 per Mmbtu of natural gas, respectively. Beginning in 2012, we began reporting our NGLs separately. In 2011, the NGLs were reported as a component of natural gas. The reference price at December 31, 2013 and 2012 used in the above table was $39.92 and $46.57 per Bbl for NGLs, respectively. 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 trailing 12 month average of realized prices for NGLs.

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

(in thousands)	Amount
Year ended December 31, 2013:	
Sales and transfers of oil and natural gas produced	$ (450,415)
Net changes in prices and production costs	582,725
Extensions and discoveries, net of future development and production costs	197,223
Development costs during the period	55,196
Changes in estimated future development costs	(251,484)
Revisions of previous quantity estimates	98,283
Sales of reserves in place	(315,758)
Purchase of reserves in place	604,366
Accretion of discount before income taxes	69,615
Changes in timing and other	(33,625)
Net change in income taxes	—
Net change	$ 556,126
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

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	2013	2012	2011	2010 and prior
Property acquisition costs	$ 376,825	$ 135,125	$ 4,982	$ 93,373	$ 143,345
Exploration and development	12,360	12,360	—	—	—
Capitalized interest	36,122	13,618	13,824	8,317	363
Total	$ 425,307	$ 161,103	$ 18,806	$ 101,690	$ 143,708

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, 2013 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, 2013, using criteria established in *Internal Control-Integrated Framework (1992)* 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 internal control over financial reporting. There were no changes in EXCO's internal control over financial reporting that occurred during the quarter ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, EXCO's internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required in response to this Item 10 is incorporated herein by reference to our Definitive Proxy Statement to be filed with the 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 of 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 26, 2014

/s/ Harold L. Hickey

Harold L. Hickey
President and Chief Operating Officer

/s/ Mark F. Mulhern

Mark F. Mulhern
Executive Vice President, Chief Financial Officer and Interim Chief Accounting Officer

/s/ Jeffrey D. Benjamin

Jeffrey D. Benjamin
Non-Executive Chairman

/s/ Earl E. Ellis

Earl E. Ellis
Director

/s/ B. James Ford

B. James Ford
Director

/s/ Samuel A. Mitchell

Samuel A. Mitchell
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	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.
2.2	First Amendment to Unit Purchase and Contribution Agreement and Closing Agreement, dated as of February 14, 2013, 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 Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2013 filed on May 1, 2013 and incorporated by reference herein.
2.3	Haynesville Purchase and Sale Agreement, by and among Chesapeake Louisiana, L.P., Empress, L.L.C., Empress Louisiana Properties, L.P. and EXCO Operating Company, LP, dated July 2, 2013, filed as an Exhibit to EXCO’s Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2013 filed on October 30, 2013 and incorporated by reference herein.
2.4	Eagle Ford Purchase and Sale Agreement, by and between Chesapeake Exploration, L.L.C. and EXCO Operating Company, LP, dated July 2, 2013, filed as an Exhibit to EXCO’s Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2013 filed on October 30, 2013 and incorporated by reference herein.
2.5	Contribution Agreement, by and among BG US Gathering Company, LLC, EXCO Operating Company, LP and Azure Midstream Holdings LLC, dated as of October 16, 2013, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated October 16, 2013 and filed on October 22, 2013 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	Second Supplemental Indenture, dated as of February 12, 2013, by and among EXCO Resources, Inc., EXCO/HGI JV Assets, LLC, EXCO Holding MLP, Inc. and Wilmington Trust Company, as trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 12, 2013 and filed on February 19, 2013 and incorporated by reference herein.
4.4	Specimen Stock Certificate for EXCO's common stock, filed as an Exhibit to EXCO's Registration Statement on Form S-3 (File No. 333-192898), filed on December 17, 2013 and incorporated by reference herein.
4.5	First Amended and Restated Registration Rights Agreement dates as of December 30, 2005, by and among EXCO Holdings Inc. and the Initial Holders (as defined therein), 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.
4.6	Registration Rights Agreement, dated March 28, 2007, by and among EXCO Resources, Inc. and the other parties thereto with respect to the 7.0% Cumulative Convertible Perpetual Preferred Stock and the Hybrid Preferred Stock, filed as an Exhibit to EXCO's Current Report on Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
4.7	Registration Rights Agreement, dated March 28, 2007, by and among EXCO Resources, Inc. and the other parties thereto with respect to the Hybrid Preferred Stock, filed as an Exhibit to EXCO's Current Report on Form 8-K dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
4.8	Joinder Agreement to Registration Rights Agreement, dated January 17, 2014, by and among EXCO Resources, Inc. and WLR IV Exco AIV One, L.P., WLR IV Exco AIV Two, L.P., WLR IV Exco AIV Three, L.P., WLR IV Exco AIV Four, L.P., WLR IV Exco AIV Five, L.P., WLR IV Exco AIV Six, L.P., WLR Select Co-Investment XCO AIV, L.P., WLR/GS Master Co-Investment XCO AIV, L.P. and WLR IV Parallel ESC, L.P, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated January 17, 2014 and filed on January 21, 2014 and incorporated by reference herein.
4.9	Joinder Agreement to Registration Rights Agreement, dated January 17, 2014, by and among EXCO Resources, Inc. and Advent Syndicate 780, Clearwater Insurance Company, Northbridge General Insurance Company, Odyssey Reinsurance Company, Clearwater Select Insurance Company, Riverstone Insurance Limited, Zenith Insurance Company and Fairfax Master Trust Fund, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated January 17, 2014 and filed on January 21, 2014 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	Amendment Number Three to the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, dated as of June 11, 2013, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 11, 2013 and filed on June 12, 2013 and incorporated by reference herein.*
10.13	Form of Restricted Stock Award Agreement, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2013 filed on August 7, 2013 and incorporated by reference herein.*
10.14	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.
10.15	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.
10.16	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	Amended and Restated Agreement of Limited Partnership of EXCO/HGI Production Partners, LP, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2013 filed on May 1, 2013 and incorporated by reference herein.
10.26	Form of Amended and Restated Limited Liability Company Agreement of EXCO/HGI GP, LLC, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2013 filed on May 1, 2013 and incorporated by reference herein.
10.27	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.
10.28	Transition Consulting Agreement, dated February 28, 2013, by and between EXCO Resources, Inc. and Stephen F. Smith, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 28, 2013 and filed on March 6, 2013 and incorporated by reference herein.*
10.29	Letter Agreement, dated March 1, 2013, by and between EXCO Resources, Inc. and Mark Mulhern, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 28, 2013 and filed on March 6, 2013 and incorporated by reference herein.*
10.30	EXCO Resources, Inc. 2013 Management Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 28, 2013 and filed on March 6, 2013 and incorporated by reference herein.*

10.31 Credit Agreement, dated as of February 14, 2013, among EXCO/HGI JV Assets, LLC, 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 Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2013 filed on May 1, 2013 and incorporated by reference herein.

10.32 First Amendment to Credit Agreement, dated as of March 5, 2013, by and among EXCO/HGI JV Assets, LLC, 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 Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2013 filed on May 1, 2013 and incorporated by reference herein.

10.33 Amended and Restated Credit Agreement, dated as of July 31, 2013, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lender parties thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Form 8-K, dated as of August 19, 2013 and filed on August 23, 2013 and incorporated by reference herein.

10.34 First Amendment to Amended and Restated Credit Agreement, dated as of August 28, 2013, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lender parties thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Form 8-K, dated as of August 28, 2013 and filed on September 4, 2013 and incorporated by reference herein.

10.35 Participation Agreement, dated July 31, 2013, among Admiral A Holding L.P., Admiral B Holding L.P. and EXCO Operating Company, LP, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2013 filed on August 7, 2013 and incorporated by reference herein.

10.36 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.

10.37 MVC Letter Agreement, dated November 15, 2013, among BG US Production Company, LLC, BG US Gathering Company, LLC, EXCO Operating Company, LP, Azure Midstream Energy LLC (formerly known as TGGT Holdings, LLC) and TGG Pipeline, Ltd, filed as an Exhibit to EXCO’s Current Report on Form 8-K, dated November 15, 2013 and filed on November 21, 2013 and incorporated by reference herein.

10.38 Exercise Commitment Letter, dated November 22, 2013, by and among EXCO Resources, Inc., WLR Recovery Fund IV XCO AIV I, L.P., WLR Recovery Fund IV XCO AIV II, L.P., WLR Recovery Fund IV XCO AIV III, L.P., WLR Select Co-Investment XCO AIV, L.P., WLR/GS Master Co-Investment XCO AIV, L.P. and WLR IV Parallel ESC, L.P, filed as an Exhibit to EXCO’s Current Report on Form 8-K, dated November 22, 2013 and filed on November 25, 2013 and incorporated by reference herein.

10.39 Exercise Commitment Letter, dated November 22, 2013, by and among EXCO Resources, Inc. and Hamblin Watsa Investment Counsel Ltd, filed as an Exhibit to EXCO’s Current Report on Form 8-K, dated November 22, 2013 and filed on November 25, 2013 and incorporated by reference herein.

10.40 Investment Agreement, dated December 17, 2013, by and among WLR Recovery Fund IV XCO AIV I, L.P., WLR Recovery Fund IV XCO AIV II, L.P., WLR Recovery Fund IV XCO AIV III, L.P., WLR Select Co-Investment XCO AIV, L.P., WLR/GS Master Co-Investment XCO AIV, L.P., WLR IV Parallel ESC, L.P. and EXCO Resources, Inc., filed as an Exhibit to EXCO’s Registration Statement on Form S-3 dated December 17, 2013 and filed on December 17, 2013 and incorporated by reference herein.

10.41 Investment Agreement, dated December 17, 2013, by and between Hamblin Watsa Investment Counsel Ltd., as representative of several investors, and EXCO Resources, Inc., filed as an Exhibit to EXCO’s Registration Statement on Form S-3 dated December 17, 2013 and filed on December 17, 2013 and incorporated by reference herein.

10.42 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.*

10.43	Settlement Agreement and Mutual Release and Waiver of Claims, dated November 20, 2013, by and between EXCO Resources, Inc. and Douglas H. Miller, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 20, 2013 and filed on November 25, 2013 and incorporated by reference herein.*
10.44	Bonus and Retention Agreement, dated January 17, 2014, by and between William L. Boeing and EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated January 17, 2014 and filed on January 24, 2014 and incorporated by reference herein.*
10.45	Bonus and Retention Agreement, dated January 17, 2014, by and between Harold L. Hickey and EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated January 17, 2014 and filed on January 24, 2014 and incorporated by reference herein.*
10.46	Bonus and Retention Agreement, dated January 17, 2014, by and between Mark F. Mulhern and EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated January 17, 2014 and filed on January 24, 2014 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 KPMG LLP as it relates to TGGT Holdings, LLC, filed herewith.
23.3	Consent of Lee Keeling and Associates, Inc., filed herewith.
23.4	Consent of Netherland, Sewell & Associates, Inc., filed herewith.
23.5	Consent of Ryder Scott Company, L.P., filed herewith.
23.6	Consent of Haas Petroleum Engineering Services, Inc., filed herewith.
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Principal Executive Officer of EXCO Resources, Inc., filed herewith.
31.2	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Principal Financial Officer of EXCO Resources, Inc., filed herewith.
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of Principal Executive Officer and Principal Financial Officer of EXCO Resources, Inc., filed herewith.
99.1	2013 Report of Lee Keeling and Associates, Inc., filed herewith.
99.2	2013 Report of Netherland, Sewell & Associates, Inc., filed herewith.
99.3	2013 Report of Ryder Scott Company, L.P., filed herewith.

99.4	EXCO/HGI JV Assets, LLC 2013 Report of Lee Keeling and Associates, Inc., filed herewith.
99.5	Consolidated Financial Statements of TGGT Holdings, LLC, for the period from January 1, 2013 to November 14, 2013 and for the Years Ended December 31, 2012 and 2011, 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.

DIRECTORS

JEFFREY D. BENJAMIN [1, 2, 3]
Non-Executive Chairman of the Board – EXCO Resources, Inc.
Senior Advisor – Cyrus Capital Partners, LP

EARL E. ELLIS [4]
Chairman and Chief Executive Officer – Whole Harvest Products

B. JAMES FORD [2, 3]
Managing Director – Oaktree Capital Management, L.P.

SAMUEL A. MITCHELL [1, 2, 3]
Managing Director – Hamblin Watsa Investment Counsel

T. BOONE PICKENS
Chairman and Chief Executive Officer – BP Capital L.P.

WILBUR L. ROSS, JR. [2, 3]
Chairman and Chief Executive Officer – WL Ross & Co. LLC

JEFFREY S. SEROTA [1, 2, 3]
Senior Advisor – Ares Management LLC

ROBERT L. STILLWELL [1, 2, 3]
Retired General Counsel – BP Capital L.P.

1 Audit Committee Member
2 Compensation Committee Member
3 Nominating and Corporate Governance Committee Member
4 Mr. Ellis has decided not to stand for re-election at the 2014 annual shareholder meeting

OFFICERS

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

RICHARD A. BURNETT
Vice President and Chief Accounting Officer

MICHAEL R. CHAMBERS, SR.
Vice President of Operations and Asset Management

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, Heath and Safety

SCOTT M. HERSTEIN
Vice President of Business Development

DANIEL W. HIGDON
Vice President of Land

HAROLD H. JAMESON
Vice President of Asset Management

CHRISTOPHER C. PERACCHI
Treasurer and Director of Finance and Investor Relations

STEPHEN E. PUCKETT
Vice President of Reservoir Engineering

MARCIA R. SIMPSON
Vice President of Engineering

ROBERT L. THOMAS
Chief Information Officer

SHAREHOLDER INFORMATION

Shareholder Relations

Christopher C. Peracchi
Treasurer and Director of Finance and Investor Relations
214.368.2084

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 2014 Annual Meeting of Shareholders will be held on Thursday, May 22, 2014 at 10:00 a.m. local time, at the:

Westin Galleria Dallas
13340 Dallas Parkway
Dallas, Texas 75240

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

30,344
(As of March 15, 2014)

EXCO Resources, Inc.
12377 Merit Drive
Suite 1700
Dallas, Texas 75251
PHONE 214.368.2084
FAX 214.368.2087
www.excoresources.com

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