EXCO Resources, Inc.

2014

ANNUAL REPORT

Dear Fellow Shareholders,

We appreciate your decision to invest in EXCO Resources and are committed to being good stewards of your capital. While the current commodity environment is challenging, we have taken steps in 2014 and 2015 to improve EXCO's position and manage through this commodity cycle. We have enhanced our liquidity, reduced our headcount, and demonstrated that we are an efficient operator, as we manage our capital and expense spending and leverage our technical expertise to opportunities across our portfolio.

In March 2015, we entered into an agreement with Bluescape Resources Company LLC ("Bluescape") whereby John Wilder, Executive Chairman of Bluescape, will become Executive Chairman of EXCO's Board of Directors. EXCO and Bluescape are currently developing a strategic business plan focused on four key areas:

1. Liability management,
2. Portfolio repositioning,
3. Cost leadership, and
4. Risk management.

We are excited to be partnering with John and his team from Bluescape as we leverage their experiences and insights and develop a plan to lead EXCO forward and create shareholder value.

We continue to monitor commodity prices, adjusting levers around our operations to maximize returns and manage our capital structure and cash flow. We believe this cycle brings with it opportunities to build long term value for our investors. We are committed to this objective.

EXCO is focused on leveraging the experience of our technical and operations team. EXCO currently operates more than 840 shale wells and has significant acreage positions in three strategic shale plays in the United States. We have great optionality and upside in our drilling location inventory and the Company will benefit from long term macro improvements in commodity prices.

During 2014, your Company achieved significant accomplishments. Through a combination of efficient development of our asset base, strategic divestitures and financing transactions, we exited the year with lower leverage and significant liquidity that together help position EXCO for future growth. Highlights of these accomplishments include:

Asset Base Development

- Drilled 122 gross wells and turned to sales 98 gross wells,
- Improved the efficiency of our drilling and completion operations and reduced well costs, and
- Positively impacted reserves with the results of our successful drilling and completion program in the Shelby area of East Texas.

Strategic Divestitures

- Sold non-operated asset in the Permian Basin for $68 million, and
- Sold remaining interest in Compass Production Partners and received $119 million and removed $83 million of Compass' debt from our balance sheet.

Finance Activities

- Raised $273 million through a common stock rights offering with the support of our broad shareholder base, including our largest investors,
- Issued $500 million of senior unsecured notes due in 2022, and
- Suspended the common stock dividend.

We have recently executed other operational initiatives to unlock upside in our asset base, despite the current commodity price environment. In North Louisiana, we have completed six Haynesville refracture stimulations of various designs with positive results. We have a large pool of wells that are candidates for potential refracture stimulations as we further refine the techniques and costs to improve our returns. We recently turned to sales a Bossier shale well in North Louisiana using our restricted flowback methodology focused on pressure maintenance instead of production rate. The well is performing in-line with our expectations and based on the enhanced completion methods, existing in-place infrastructure, and our ability to reduce drilling and completion costs, we believe we can develop as many as 300 Bossier shale drilling locations in North Louisiana in the future. In South Texas, we drilled two operated Buda wells that had initial production rates in excess of 500 barrels of oil per day and plan to drill additional Buda wells during the remainder of 2015.

For 2015, we continue to focus on efficiently developing our asset base and reducing costs throughout the organization. Managing our balance sheet, maintaining ample liquidity and simplifying our organization remain top priorities. We are demonstrating fiscal discipline with a focus on projects that:

- Produce attractive returns in the current commodity price environment,
- Add proved reserves to our portfolio, and
- Increase or maintain high value acreage positions.

Our East Texas Shelby asset is our natural gas focus area in 2015 and beyond as our drilling and completion activities add proved developed producing wells that were not categorized as proved locations at year-end, and add proved undeveloped locations and reserves to our asset base as we continue to develop this area. We also believe there is potential for additional upside in our Shelby reserves based on our current drilling and completion designs.

In February 2015, we proactively worked with our banks and amended our credit agreement to provide financial flexibility to strategically develop our asset base, while deferring a significant amount of our drilling inventory. We are highly confident in the quality of the credit agreement's underlying collateral asset base and thank our bank group for their continued support of EXCO.

In March 2015, we entered into a four-year services and investment agreement with Bluescape. John Wilder and his team at Bluescape have a demonstrated track record of increasing shareholder value and proven successful experiences in commercial and turnaround work, which complement EXCO's strong oil and gas operating capabilities. Bluescape's agreement with EXCO encompasses both an investing aspect and strategic advisory services, with their compensation heavily weighted towards building equity value, aligning them with your interests. Bluescape has agreed to invest $50 million in EXCO, which demonstrates a strong commitment to our company and an understanding of the quality of our people and assets, as well as optimism toward our future opportunities. This partnership is a strategic step toward working through the current commodity cycle, enhancing the value of our corporation and preparing EXCO for the future.

With the review of 2014 and our recent 2015 efforts, EXCO has significantly enhanced its liquidity as we have reduced debt from third quarter 2013 levels. We are focused in three strong positions (East Texas/North Louisiana, South Texas and Appalachia) with significant upside opportunities. 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 to protect against market fluctuations and allow us to opportunistically pursue growth opportunities. We firmly believe that as we continue to execute during this commodity cycle our stakeholders will be rewarded.

Thank you for your support of EXCO Resources.

Sincerely,

Jeffrey D. Benjamin
Chairman of the Board

Harold L. Hickey
Chief Executive Officer and President

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 10-K/A
Amendment No. 1

(Mark One)

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

For the fiscal year ended: December 31, 2014

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

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

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

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

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

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 Web site, 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 was 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 (S229.405 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 Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "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 March 31, 2015, the registrant had 273,702,116 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 $897,416,000.

EXCO RESOURCES, INC.

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EXPLANATORY NOTE

EXCO Resources, Inc. is filing this Amendment No. 1 on Form 10-K/A (this "Amendment") to its Annual Report on Form 10-K for the fiscal year ended December 31, 2014, filed on February 25, 2015 (the "Form 10-K"), solely for the purpose of amending Items 10 through 14 in Part III and Item 15 in Part IV. The information in Part III was previously omitted from the Form 10-K in reliance on General Instruction G(3) to Form 10-K, which permits such information to be incorporated in the Form 10-K by reference to a definitive proxy statement if such proxy statement is filed no later than 120 days after our fiscal year end.

We are filing this Amendment to include the Part III information in the Form 10-K because we no longer expect to file a definitive proxy statement containing this information before the date that is 120 days after our fiscal year end. Part IV is being amended to include as exhibits certain new certifications required of the principal executive officer and principal financial officer under Section 302 of the Sarbanes-Oxley Act of 2002, as amended. This Amendment hereby amends Part III, Items 10 through 14, and Part IV, Item 15 of the Form 10-K. Additionally, the reference on the cover page of the Form 10-K to the Definitive Proxy Statement for the 2015 Annual Meeting of Shareholders is hereby deleted.

Except as described above, no other changes have been made to the Form 10-K. Other than the information specifically amended and restated herein, this Amendment does not reflect events occurring after February 25, 2015, the date the Form 10-K was filed, or modify or update those disclosures that may have been affected by subsequent events.

References to "EXCO," "EXCO Resources," "Company," "we," "us," and "our" in this report refer to EXCO Resources, Inc. together with its consolidated subsidiaries.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The board of directors is currently comprised of six directors. Our directors serve until the next annual meeting of shareholders or until their respective successors have been duly elected and qualified. Pursuant to a letter agreement that the Company entered into with funds managed by Oaktree Capital Management, LP ("Oaktree" and together with the managed funds, the "Oaktree Funds") in March 2007, Oaktree has the right to nominate one director for election at any annual meeting of shareholders so long as Oaktree beneficially owns at least 10,000,000 shares of common stock. As of the record date for the 2014 annual meeting of shareholders, Oaktree owned in excess of 10,000,000 shares of common stock. As a result, Mr. Ford was nominated by Oaktree, as well as by our board of directors, for election at the 2014 annual meeting of shareholders.

The following table sets forth the name, age and positions of each director currently serving on our board of directors:

Name	Age	Position
Jeffrey D. Benjamin(1)(2)(3)	53	Director; Non-Executive Chairman
B. James Ford(2)(3)	46	Director
Samuel A. Mitchell (1)(2)(3)	71	Director
Wilbur L. Ross, Jr.(2)(3)	77	Director
Jeffrey S. Serota (1)(2)(3)	49	Director
Robert L. Stillwell(1)(2)(3)	78	Director

(1) Member of the audit committee.
(2) Member of the compensation committee.
(3) Member of the nominating and corporate governance committee.

The biographies of our directors are as follows:

Jeffrey D. Benjamin became non-executive chairman of our board of directors in November 2013 and has been serving as one of our directors since October 2005. Mr. Benjamin previously served as a director from August 1998 through July 2003 and a director of our parent holding company from July 2003 through its merger into us. Since June 2008, Mr. Benjamin has been a Senior Advisor to Cyrus Capital Partners, LP ("Cyrus Capital Partners"). Mr. Benjamin also serves as a Consultant to Apollo Management, LP ("Apollo Management") and from September 2002 until June 2008, Mr. Benjamin served as a Senior Advisor to Apollo Management. With his service at Apollo Management and Cyrus Capital Partners, Mr. Benjamin has extensive financial, capital markets and strategic experience. Mr. Benjamin is currently a director of American Airlines Group Inc., Caesars Entertainment Corporation and Chemtura Corporation and Chairman of the Board of Directors of A-Mark Precious Metals, Inc. During the past five years, Mr. Benjamin also served on the board of directors of Virgin Media Inc. and Spectrum Group International, Inc. In connection with his service as a director of nine public companies other than EXCO over the past ten years, Mr. Benjamin has served on five compensation committees (including two as chairman), five audit committees and five nominating and corporate governance committees (including two as chairman), all of which provide him with important insights into corporate governance, financial reporting and oversight, executive compensation and board functions. In addition, Mr. Benjamin has deep knowledge of the Company and its business, having served on our and our affiliates' boards since October 2005 and prior to that from 1998 through 2003. Mr. Benjamin holds a Master of Science (MBA) in Management from the Sloan School of Management at Massachusetts Institute of Technology, with a concentration in Finance, and has 28 years of investment banking and investment management experience.

B. James Ford became one of our directors in December 2007. Mr. Ford is a Managing Director of Oaktree where he has worked since 1996. Mr. Ford is a portfolio manager of Oaktree's global principal group, which invests in controlling and minority positions in private and public companies. Mr. Ford serves on the board of directors of Contango Oil & Gas Company, Oaktree Capital Group, LLC and Townsquare Media, LLC as well as a number of private companies and not-for-profit entities, and formerly served on the board of directors of Dial Global, Inc. and Crimson Exploration, Inc. prior to its merger with Contango Oil & Gas Company. Prior to becoming a portfolio manager, Mr. Ford led the group's efforts in the media and energy sectors. Mr. Ford's background and experience provide him with extensive investment, capital markets and strategic experience, as well as important insights into corporate governance and board functions. He is also an active member of the Children's Bureau Board of Directors and serves as a trustee for the Stanford Graduate School of Business Trust. Mr. Ford received a B.A. degree in Economics from the University of California at Los Angeles and a Masters of Business Administration degree from the Stanford Graduate School of Business.

Samuel A. Mitchell became one of our directors in June 2013. Mr. Mitchell has served as a director of Overstock.com, Inc. since October 2010. Mr. Mitchell was formerly a director of International Coal Group, Inc. from 2006 until its acquisition in 2011. Since 2004, Mr. Mitchell has been a Managing Director of Hamblin Watsa Investment Counsel ("Hamblin Watsa"), a wholly-owned subsidiary of Fairfax Financial Holdings, Inc. ("Fairfax Financial"), a Toronto-based property and casualty insurance holding company. Hamblin Watsa is responsible for managing the investments of Fairfax Financial. From 2005 to 2007, Mr. Mitchell was a director of Odyssey Re Holdings Corp., a majority-owned subsidiary of Fairfax Financial that is an underwriter of property and casualty treaty and facultative reinsurance. Prior to joining Hamblin Watsa, Mr. Mitchell was Managing Director and co-founder in 1993 of Marshfield Associates, a Washington, D.C.-based investment counsel firm. Mr. Mitchell also has experience in the healthcare industry, having served as a Director of Research and Federal Relations for the Federation of American Health Systems from 1983 to 1993, and as Director of Research for the Health Industry Manufacturers Association from 1977 to 1981. In 1973, he co-founded Research from Washington, which advised large institutional investors on the outlook and economic impact of legislation and federal government initiatives. Mr. Mitchell started his career in 1968 with the Washington, D.C.-based investment counsel firm, Davidge and Co. He has a B.A. from Harvard College and an M.B.A. from Harvard Business School. Mr. Mitchell's experience as Managing Director of Hamblin Watsa, and his four decades of business experience provide him with extensive investment, capital markets and financial experience as well as important insights into financial reporting, oversight and Board functions.

Wilbur L. Ross, Jr. became one of our directors in March 2012. Mr. Ross is the Founder, Chairman and Chief Strategy Officer of WL Ross & Co. LLC ("WL Ross"), a private equity firm. Mr. Ross was also formerly the Chief Executive Officer of WL Ross prior to April 30, 2014 when he became its Chairman and Chief Strategy Officer. In March 2014, Mr. Ross became the Chairman and Chief Executive Officer of WL Ross Holding Corp, a special purpose acquisition company. Mr. Ross is currently a member of the board of directors of ArcelorMittal, the world's largest steel and mining company; DSS Holdings LP, a shipping transportation company; Sun Bancorp, Inc.; and the Bank of Cyprus. Mr. Ross formerly served as a member of the board of directors of many banks, financial and other companies, including but not limited to, The Governor and Company of the Bank of Ireland, a commercial bank in Ireland until June 2014, BankUnited, Inc. until March 2014; Talmer Bancorp., Assured Guaranty, an insurance company, International Textile Group, NBNK Investments PLC, PB Materials Holdings, Inc., Ohizumi Manufacturing, Ocwen Financial Corp., Navigator Holdings, a marine transport company, and International Automotive Components until November 2014; Plascar Participacoes SA, a manufacturer of automotive interiors, until January 2014 and Air Lease Corporation, an aircraft leasing company from 2010 to December, 2013; International Coal Group from April 2005 to June 2011, Montpelier Re Holdings Ltd., a reinsurance company, from 2006 to March 2010; The Greenbrier Companies, a supplier of transportation equipment and services to the railroad industry from

June 2009 until January 2013. Mr. Ross was Executive Managing Director of Rothschild Inc. for 24 years before acquiring that firm's private equity partnerships in 2000. Mr. Ross is a graduate of Yale University and of Harvard Business School. Through the course of Mr. Ross' career, he has served as a principal financial adviser to, investor in, and director of various companies across the globe operating in diverse industries, and he has assisted in restructuring more than $400 billion of corporate liabilities. Mr. Ross possesses unique skills, qualities and experience, as evidenced by his background, which we believe adds significant value to board discussions and to our success.

Jeffrey S. Serota became one of our directors in March 2007. Mr. Serota previously served as a director of EXCO Resources and EXCO Holdings from July 2003 until October 2005. He served as a Senior Partner of Ares, an alternative asset investment firm, from September 1997 until his retirement in December 2012. Mr. Serota subsequently served as a Senior Advisor to Ares until December 31, 2013. Prior to joining Ares, Mr. Serota worked at Bear Stearns Companies, Inc. from March 1996 to September 1997, where he specialized in providing investment banking services to financial sponsor clients of the firm. He currently serves on the board of directors of SandRidge Energy, Inc. and CIFC Corp., and previously served on the boards of directors of Lyondell Basell Industries N.V. from May 2010 to May 2011, Douglas Dynamics, Inc. from 2004 until October 2010 and WCA Waste Corporation from September 2006 until March 2012. Mr. Serota has over 20 years of experience managing investments in, and serving on the boards of directors of, companies operating in various industries, including in the oil and natural gas exploration and production industry. Mr. Serota's background and experience provide him with extensive investment, capital markets and strategic experience, as well as important insights into corporate governance, financial reporting and oversight, executive compensation and board functions. Mr. Serota received a Bachelor of Science degree in Economics from the University of Pennsylvania's Wharton School of Business and received a Master of Business Administration degree from UCLA's Anderson School of Management.

Robert L. Stillwell became one of our directors in October 2005. Mr. Stillwell served as the General Counsel of BP Capital, L.P., Mesa Water, Inc. and affiliated companies engaged in the petroleum business from 2001 until he retired in March 2013. Mr. Stillwell was a lawyer and Senior Partner at Baker Botts LLP in Houston, Texas from 1961 to 2001. He also served as a director of Mesa Petroleum Co. and Pioneer Natural Resources Company from 1969 to 2001. Mr. Stillwell's background and experience provide him with extensive knowledge of the oil and natural gas industry as well as significant legal experience and important insights into corporate governance, executive compensation and board functions.

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

Audit Committee

The audit committee of our board of directors recommends the appointment of our independent registered public accountants, reviews our internal accounting procedures and financial statements and consults with and reviews the services provided by our independent registered public accountants, including the results and scope of their audit. The audit committee is currently comprised of Messrs. Benjamin (chair), Mitchell, Serota and Stillwell, each of whom is independent within the meaning of applicable SEC and NYSE rules. The board of directors has designated Messrs. Benjamin and Mitchell as audit committee financial experts, as currently defined under the SEC rules implementing the Sarbanes-Oxley Act of 2002. See Item 13. Certain Relationships and Related Transactions, and Director Independence— Director Independence." We believe that the composition and functioning of our audit committee complies with all applicable requirements of the Sarbanes-Oxley Act of 2002, as amended, as well as NYSE and SEC rules and regulations.

Codes of Business Conduct and Ethics

We have adopted Corporate Governance Guidelines, a Code of Business Conduct and Ethics, and a Code of Ethics for the Chief Executive Officer and Senior Financial Officers. Copies of the codes can be obtained free of charge from our website, www.excoresources.com, or by contacting us at the address appearing on the first page of this Annual Report on Form 10-K to the attention of Secretary or by telephone at (214) 368-2084. We intend to post any amendments to, or waivers from, our Code of Ethics that apply to our chief executive officer or senior financial officers on our website at www.excoresources.com.

Executive Officers

The following table sets forth certain information with respect to our current executive officers.

Name	Age	Position
Harold L. Hickey	59	Chief Executive Officer and President
William L. Boeing	60	Vice President, General Counsel and Secretary
Richard A. Burnett	41	Vice President, Chief Financial Officer and Chief Accounting Officer

Harold L. Hickey became our Chief Executive Officer in March 2015 and President in February 2013. Mr. Hickey previously served as Chief Operating Officer from October 2005 until March 2015. From October 2005 until February 2013, Mr. Hickey served as our Vice President and from January 2004 until October 2005, Mr. Hickey served as President of our wholly-owned subsidiary, North Coast Energy, Inc. Mr. Hickey was our Production and Asset Manager from February 2001 to January 2004. From April 2000 until he joined us, Mr. Hickey was Chief Operating Officer of Inca Natural Resources Group, L.P., an independent oil and natural gas exploration company. Prior to that, Mr. Hickey worked at Mobil Oil Corporation from 1979 to March 2000.

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

Richard A. Burnett became our Vice President and Chief Accounting Officer in March 2014 and our Chief Financial Officer in September 2014. Mr. Burnett previously served as our Vice President of Special Projects from the time he joined EXCO in November 2013 until March 2014. From April 2001 until joining EXCO, Mr. Burnett served in various capacities at KPMG LLP, including as a Partner in their energy transactions service practice advising a number of clients in the oil and natural gas exploration and production, oil field services, manufacturing, midstream, refining and utilities industries on, among other things, their financial reporting and securities filing requirements. Mr. Burnett also spent five years at Arthur Andersen LLP prior to joining KPMG LLP. Mr. Burnett is a certified public accountant and received a Bachelor’s degree in Accounting from Texas Tech University.

Other Officers and Divisional Managers of Our Company

Michael R. Chambers Sr., age 59, became our Vice President of Operations in February 2007 and also currently serves as the Vice President and General Manager of our East Texas/North Louisiana Division. Prior to joining EXCO, Mr. Chambers was the Operations General Manager for Anadarko Petroleum Corporation’s Eastern Region Operations from August 2006 to February 2007 and Rockies Production Manager from August 2000 to August 2006. Mr. Chambers joined Anadarko in January 2000. Mr. Chambers worked at Mobil Oil Corporation from 1979 to January 2000.

W. Justin Clarke, age 39, became our Assistant General Counsel and Chief Compliance Officer in January 2007. From September 2001 until January 2007, Mr. Clarke served as an associate at one of our outside law firms, Haynes and Boone, LLP, in Dallas, Texas.

Ronald G. Edelen, age 57, joined EXCO in October 2011 as our Vice President of Supply Chain Management. Prior to then, Mr. Edelen was Director of Supply Chain at Devon Energy Corporation. From September 2008 until October 2010, he was Director of Supply Chain Management for Matrix Services Inc. Prior to working for Matrix Services Inc., Mr. Edelen held various positions at DCP Midstream LLC from 1999 to September 2008, including Director of Materials Management and Office Administration. Prior to DCP Midstream LLC, Mr. Edelen spent his career in various Purchasing, Materials Management and Corporate Travel positions with CH2M Hill and Total Petroleum, Inc. Mr. Edelen has over 30 years of experience in the oil and natural gas industry with over 20 of those years directly involved in Supply Chain related positions in upstream, midstream and downstream companies in the U.S. and Canada. Mr. Edelen is a certified purchasing manager.

Steven L. Estes, age 60, became our Vice President of Marketing in June 2010. Prior to then, Mr. Estes served as Director of Marketing for us since July 2007. Mr. Estes held several positions with Union Pacific Resources and Anadarko Petroleum Corporation before joining us, most recently as Regional Manager of Gas Marketing from 2002 until 2007. Mr. Estes has over 30 years of experience in the oil and natural gas industry with over 20 of those years directly involved in marketing in all regions of the country.

Joe D. Ford, age 67, became our Vice President of Human Resources in November 2007. Prior to joining EXCO, Mr. Ford was the Director of Human Resources for CARBO Ceramics Inc. from June 2002 to November 2007. CARBO Ceramics Inc. supplies ceramic proppant for fracturing natural gas and oil wells and also provides well fracture diagnostic services. Prior to working for CARBO Ceramics Inc., Mr. Ford spent his career in various human resource management capacities including a subsidiary of General Dynamics as Manager of Human Resources and Comdial Corporation as Vice President of Human Resources.

Robert Gessner, age 62, became our Corporate Controller in 2014. Mr. Gessner previously served as the Controller of our Appalachia division and Controller of our wholly-owned subsidiary, North Coast Energy, Inc. Prior to joining North Coast, Mr. Gessner served in a variety of financial positions at both Belden and Blake Corporation and M.A. Hanna Company. Mr. Gessner has over 30 years of industry experience. He is a CPA and a member of the Ohio Society of CPA's.

Russell D. Griffin, age 51, joined EXCO in January 2008 and became our Vice President of Environmental, Health and Safety in June 2010. Mr. Griffin was previously our Director of Environmental, Health and Safety and Vice President of Health Safety Security and Environment for TGGT Holdings, LLC. Prior to joining EXCO, Mr. Griffin was the Senior Regulatory Representative for Hunt Oil Company, an independent international oil and natural gas exploration and production company, from August 2005 until January 2008. Mr. Griffin joined Hunt Oil Company in August of 1984 and held numerous positions in their Gulf Coast exploration and production operations until August 2005.

Daniel W. Higdon, age 57, became our Vice President of Land in September 2013. Prior to joining EXCO, Mr. Higdon was Vice President – Land for Devon Energy Corporation's Southern Division from March 2006 to March 2013 and the Central Division Land Manager from January 2002 to March 2006 overseeing the Barnett Shale asset during the advent of horizontal drilling in unconventional shales. Mr. Higdon began his career with Mitchell Energy Corporation in 1983 and held various Land positions culminating as Regional Land Manager coordinating the acquisition of the Barnett Shale asset until Devon acquired Mitchell in 2002.

Harold H. Jameson, age 47, became a Vice President in March 2011 and also serves as the General Manager of our East Texas/North Louisiana joint venture. His primary focus is on the development of our Haynesville/Bossier shale assets. Prior to the Haynesville shale project, Mr. Jameson served as General Manager of our Vernon Field. Prior to joining EXCO in April 2007, he was employed at Anadarko Petroleum Corporation from 1991 to 2007 where he gained valuable experience in a variety of operating areas including U.S. onshore, offshore and international businesses in both development and exploration roles. Since 2001, Mr. Jameson has been responsible for Asset Management, Production Engineering, Reservoir Engineering and Field Development in the Central Texas, East Texas and North Louisiana operating areas.

Christopher C. Peracchi, age 46, became our Treasurer and Director of Finance and Investor Relations in May 2013 and became our Vice President of Finance and Investor Relations in September 2014. Mr. Peracchi served as the Associate Director of Corporate Development and Investor Relations at Nabors Industries from April 2012 to April 2013 and Director of Finance and Investor Relations at Superior Well Services from March 2009 to April 2012. Mr. Peracchi has over 11 years of experience in Energy Investment Banking at KeyBanc Capital Markets and A.G. Edwards & Sons. Mr. Peracchi also spent four years at Coopers & Lybrand. Mr. Peracchi is a certified public accountant and received a Master's in Business Administration from the University of Michigan and a Bachelor's degree from Babson College.

Stephen E. Puckett, age 56, became our Vice President of Reservoir Engineering in December 2006. Mr. Puckett was our Manager of Engineering and Operations from April 2000 until December 2006. From January 1998 until April 2000 he served as a petroleum engineering consultant for Petra Resources, Inc. From March 1993 until January 1998 he worked for Enserch Exploration, Inc. as a reservoir engineer. From May 1981 until January 1993 he was employed by Oryx Energy Company as an operations engineer and reservoir engineer. He is a registered professional engineer in Texas and a member of the Society of Petroleum Engineers.

Marcia Reeves Simpson, age 58, joined EXCO in March 2008 as our Vice President of Engineering. Ms. Simpson was employed by J-W Operating Company—Cohort Energy as its Acquisition & Divestiture and Reservoir Engineering Manager from September 2004 until March 2008. From January 2001 until September 2004, Ms. Simpson was a Vice President for Energy Virtual Partners, a start-up exploration and production company. From September 1987 until January 2000, she worked for Mobil Oil Corporation in various leadership positions including U.S. Technology Leader. From June 1978 to September 1987, she worked in several engineering positions for Gulf Oil Corporation/Chevron Corporation. She is a registered professional engineer in Louisiana and she has served in various leadership roles with the Gas Research Institute, the Society of Petroleum Engineers and the Society of Women Engineers over her 30 year career.

Robert L. Thomas, age 55, became our Chief Information Officer in May 2008. Prior to joining EXCO, Mr. Thomas was the Director of Strategy and Architecture in Global Information Services at ConocoPhillips. Prior to working for ConocoPhillips, Mr. Thomas served Burlington Resources in the US, Canada and UK from 1994 to 2006 in various IT management capacities. Prior to Burlington Resources, Mr. Thomas worked for Oryx Energy Company. He began his career in the seismic data processing center at Sun Oil Company in 1981, and is an active member of the Society of Exploration Geophysicists.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our officers and directors, and persons who own more than 10% of a registered class of our equity securities, to file reports of ownership and changes of ownership with the SEC. Our officers, directors and 10% shareholders are required by SEC regulations to furnish us with copies of all Section 16(a) forms so filed. Based solely on review of copies of such forms received, we believe that, during the last fiscal year, all filing requirements under Section 16(a) applicable to our officers, directors and 10% shareholders were timely met.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Executive Summary

Named Executive Officers. For purposes of disclosure in this Annual Report on Form 10-K, the "Named Executive Officers" for the year ended December 31, 2014 include the following persons:

- Harold L. Hickey, our President and Chief Operating Officer as of December 31, 2014;
- Richard A. Burnett, our Vice President, Chief Financial Officer and Chief Accounting Officer as of December 31, 2014; and
- William L. Boeing, our Vice President, General Counsel and Secretary as of December 31, 2014.

Unless otherwise indicated, references in this Annual Report on Form 10-K to Named Executive Officers do not include Mark F. Mulhern, our former Executive Vice President and Chief Financial Officer, who resigned from the Company effective September 19, 2014. Mr. Mulhern forfeited all of his unvested shares of restricted stock, restricted stock units and stock options and did not receive any severance or other benefits in connection with his resignation from the Company.

General Philosophy. We believe that the most effective compensation program is one that is designed to reward all of our employees, including but not limited to, our Named Executive Officers, for the achievement of our short-term and long-term strategic goals using a pay for performance system that ultimately drives toward the achievement of increased total shareholder return. Through this strategy, we seek to closely align the interests of our Named Executive Officers with the interests of our shareholders. Our Named Executive Officers' total compensation is comprised of a mix of base salary, performance-based cash bonus, long-term incentive compensation, retirement and other benefits and perquisites and other personal benefits intended to fulfill these objectives.

Our compensation committee annually reviews our executive compensation program to determine what changes should be made to the individual components of the program in order to fulfill our objectives. Our compensation committee has taken several significant steps to align our executive compensation program with these objectives over the past several years, including the following:

- Eliminating an annual (end of year) executive compensation review and decision process by instead instituting compensation reviews and decisions for various components of our executive compensation program at multiple points during the course of a year in an effort to promote retention throughout the year;
- conducting an annual review of base salary and cash bonuses (during the first fiscal quarter) and adopting annual management incentive plans (beginning in 2013) that award annual cash bonuses based on a combination of the Company's achievement of performance-based metrics and the compensation committee's discretion; and
- conducting an annual review of equity compensation awards and making an annual grant of equity awards (during the second or third fiscal quarter) with a combination of time-based and performance-based vesting conditions (e.g., stock price and total shareholder return).

2014 Business Overview. In 2014, our primary strategy focused on the exploitation and development of our core Haynesville and Eagle Ford shale assets through a disciplined development program that was primarily funded with cash flows from our operations. We sought to improve our operating margins as a result of initiatives that were aimed to reduce costs in order to preserve liquidity and capital resources in preparation for future growth. We also completed significant transactions to enhance our liquidity, including the following:

- We closed a rights offering and related private placement of our common stock (the "Rights Offering") on January 17, 2014 which resulted in the issuance of 54,574,734 shares of our common stock for gross proceeds of $272.9 million.
- On March 24, 2014, we closed a purchase and sale agreement with a private party for the sale of our interest in certain non-operated assets in the Permian Basin including producing wells and undeveloped acreage for approximately $68.2 million, after final purchase price adjustments.
- On April 16, 2014, we completed a public offering of $500.0 million in aggregate principal amount of senior unsecured notes due April 15, 2022 ("2022 Notes"). We received net proceeds of approximately $490.0 million after offering fees and expenses. The 2022 Notes bear interest at a rate of 8.5% per annum, payable in arrears on April 15 and October 15 of each year.
- On October 31, 2014, we closed a purchase agreement with an affiliate of Harbinger Group, Inc. to sell our 25.5% economic interest in Compass Production Partners, LP ("Compass") for $118.8 million in cash.

Our Named Executive Officers were instrumental in arranging and carrying out each of these transactions. As a result of these transactions, we enhanced our existing liquidity in order to maintain financial flexibility particularly in the current low commodity price environment and plan for future growth.

Key Compensation Decisions in 2014. We believe that our compensation for Named Executive Officers (including Mr. Mulhern) for fiscal 2014 was consistent with the objectives of our compensation philosophy and with our performance, and were also consistent with the purposes of retaining and incentivizing our Named Executive Officers. The key compensation actions taken with respect to our Named Executive Officers in 2014 (including Mr. Mulhern) are summarized below:

- In January 2014, to retain and incentivize them to continue providing services in light of the senior management changes in 2013 and the search process for a replacement chief executive officer, the compensation committee recommended, and the board of directors approved, a separate Bonus and Retention Agreement (as defined below) with each of Messrs. Boeing, Hickey and Mulhern that provides for certain benefits upon a Qualifying Termination (as defined below).
- On April 21, 2014, our board of directors adopted the 2014 Management Incentive Plan (the "2014 Management Incentive Plan") to pay a cash bonus to our officers and replace the management incentive plan for 2013 (the "2013 Management Incentive Plan"). The 2014 Management Incentive Plan provides performance-based metrics that account for 60% of the bonus for each officer with the compensation committee having discretion over the remaining 40% of the bonus.
- On June 30, 2014, the compensation committee (i) approved a form of performance-based restricted stock unit award agreement under the Incentive Plan and the performance criteria for grants of restricted stock units ("RSUs") subject to performance-based vesting conditions and (ii) granted performance-based RSUs to our Named Executive Officers.
- In September 2014, in connection with Mr. Burnett's appointment as Chief Financial Officer, he was awarded (i) an increased annual base salary of $475,000, (ii) 100,000 shares of restricted stock, (iii) 39,063 shares of time-based restricted stock and 39,063 performance-based RSUs, and (iv) an increased target bonus equal to 80% of his base salary under the 2014 Management Incentive Plan. In addition, we entered into a retention agreement with Mr. Burnett in connection with his appointment that provides for certain benefits upon a Qualifying Termination.

Consistency with Compensation Objectives. We believe that the compensation decisions in 2014 were consistent with the objectives of our compensation philosophy because:

- Competition for highly skilled, technical employees in the oil and natural gas industry remained intense in 2014;
- We continue to model our executive compensation incentives toward achieving long-term equity growth by using significant vesting conditions, including conditions tied to our future stock price, to reward and retain our Named Executive Officers for contributions to the Company's long-term performance and value;
- Cash bonus payouts for Named Executive Officers and other officers under the 2014 Management Incentive Plan are tied to the achievement of several key performance-based metrics; and
- We have retained several key officers and other management personnel and believe that our senior management team, together with a new chief executive officer, will work to fulfill our business strategy and increase shareholder return.

Overview of Compensation Program

The compensation committee of our board of directors has responsibility for establishing, implementing and continually monitoring adherence with our compensation philosophy. The compensation committee reviews and recommends to our board of directors the compensation and benefits for our executive officers, administers our stock plans and assists with the establishment of general policies relating to compensation and benefits for all of our employees. The compensation committee seeks to ensure that the total compensation paid to our officers is fair, reasonable and competitive. Generally, the types of compensation and benefits provided to our executive officers are similar to those provided to our other officers and managers.

The following discussion summarizes in more detail our executive compensation program, including our compensation objectives and philosophies, the processes and sources of input that are considered in determining compensation for our Named Executive Officers and an analysis of the compensation paid to or earned by our Named Executive Officers in 2014.

Compensation Philosophy and Objectives

We believe that the most effective compensation program is one that is designed to reward all of our employees, not just executives, for the achievement of our short-term and long-term strategic goals.

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

- to attract, retain and motivate highly qualified and experienced individuals;
- to ensure that a significant portion of their total compensation is “at risk” in the form of equity compensation;
- to ensure annual cash bonus payouts for Named Executive Officers and other officers are tied to the achievement of several key performance-based metrics; and
- to offer competitive compensation packages that are consistent with our core values.

Over the last several years, our focus was to maximize shareholder value by increasing reserves, production and cash flow in a cost-effective manner through the appraisal and development of the Company’s shale resources, particularly in the Haynesville and Eagle Ford shale formations. Proper development of these shale properties requires personnel with significant technical knowledge and expertise that encompasses analyzing geological and geophysical data and possessing the skills necessary to drill and complete these high-pressure wells to maximize the economic potential. As a result, we have cultivated a skilled workforce with core competencies exploiting and developing complex shale resources. This skilled workforce is integral to the execution of our corporate strategy.

Competition for skilled, technical employees in the oil and natural gas industry remained intense throughout 2014, particularly for individuals with experience analyzing and exploiting shale resources. In 2014, we implemented the use of performance-based RSUs and continued our philosophy of using restricted stock with significant time and performance-based vesting conditions as an incentive for our officers, including our Named Executive Officers, and our other selected employees primarily because we believed:

- restricted stock awards and performance-based RSUs help ensure that a significant portion of selected employees’ total compensation is “at risk”;
- restricted stock awards and performance-based RSUs are designed to allow selected employees to acquire a direct ownership interest in us over time and therefore be fully aligned with our shareholders;
- restricted stock awards and performance-based RSUs with vesting conditions tied to the price of our common stock align the interest of our officers with our shareholders;
- restricted stock awards are designed to be less vulnerable than stock options to volatility in our stock price, which is often impacted by volatile swings in the price of natural gas, and therefore serve as a more meaningful long-term retention vehicle even if our stock price decreased in the short-term; and
- based on market data provided by our outside compensation consultant, awarding restricted stock and performance-based RSUs would allow the Company to offer similar incentives to those companies with whom we compete for skilled talent since most of the companies in our peer group issue restricted stock or RSUs as part of their executive compensation incentives.

During 2014, our compensation committee decided not to award any stock options to our Named Executive Officers and implemented the use of performance-based RSUs. The performance-based RSUs are structured to incentivize our Named Executive Officers to maximize the long-term value of our common stock, with the number of shares vesting being determined based on our total shareholder return during the period from the date of grant to the third anniversary of the date of grant. The performance-based RSUs only vest and convert into shares of our common stock if our percentile rank within a peer group established by the compensation committee equals or exceeds 35% during the measurement period. For additional information concerning these awards, see "—Executive Compensation Components—Long-Term Incentive Compensation—Restricted Stock Units."

Role of Executive Officers in Compensation Decisions

Our board of directors has delegated authority to the compensation committee to make all compensation decisions for our executive officers and approve all grants of equity awards to our executive officers and certain other selected officers. The compensation committee annually reviews the performance of our chief executive officer, unless such position is vacant. In addition, our chief executive officer has historically reviewed the performance of each other executive officer on an annual basis. During the time period that we have not had a chief executive officer, our compensation committee has reviewed the performance of each other executive officer. The conclusions and recommendations based on these reviews, including with respect to salary adjustments and annual bonus award amounts, are determined by the compensation committee. The compensation committee may exercise its discretion in modifying any recommended adjustments or awards to our executives and has the final authority to establish the compensation packages for our executive officers. The compensation committee may delegate authority and responsibilities to subcommittees, as long as such subcommittees consist of not less than two members.

Setting Executive Compensation

Outside Consulting Firm. In November 2013, the compensation committee engaged Frederic Cook to conduct an annual review of our total compensation program for our Named Executive Officers, as well as for other key executives. The compensation committee selected Frederic Cook to provide these services based on, among other things, Frederic Cook's reputation, substantial insight and experience with executive compensation programs in our industry.

Independence of Consulting Firm. The compensation committee annually reviews the performance, independence and related fees paid to executive compensation consultants and has concluded that our current compensation consultant, Frederic Cook, is independent. During 2014, the Company paid Frederic Cook $119,519 in fees for its executive compensation consulting services.

Peer Group. In making compensation decisions, the compensation committee compares each element of total compensation against a peer group of publicly-traded oil and natural gas companies with similar operations and revenue. The peer group consists of companies against which the compensation committee believes we compete for talent and for shareholder investment. Our peer group in 2014 consisted of the following companies: Bill Barrett Corporation; Cabot Oil & Gas Corporation; Cimarex Energy Company; Comstock Resources Inc.; Concho Resources, Inc.; Continental Resources Inc.; Forest Oil Corporation; Penn Virginia Corporation; Petroleum Development Corporation; Quicksilver Resources Inc.; Range Resources Corporation; Rosetta Resources Inc.; Sandridge Energy, Inc.; SM Energy Company; Stone Energy Corporation; Swift Energy Company; Ultra Petroleum Corporation; W&T Offshore, Inc. and Whiting Petroleum Corporation.

In comparing the Company's executive compensation levels to those of its peer group, the compensation committee looked at base salary, cash incentives, other compensation (which includes restricted stock, RSUs, stock options, other types of equity compensation, pensions, and perquisites), and total compensation for 2013 (the most recent year for which information regarding the peer group's executive compensation was available).

Total Direct Compensation. We compete with many larger companies for top executive-level talent. Our compensation committee took into consideration a number of factors when setting and determining the total direct compensation (base salary, cash bonus and the value of the individual's equity awards granting during that year) for our Named Executive Officers (including Mr. Mulhern) in 2014, including exercise prices for existing stock options and the vesting periods for previously issued restricted stock awards. Although our compensation committee does not identify specific target ranges for the total direct compensation of each Named Executive Officer, the compensation committee generally set total direct compensation for our Named Executive Officers (including Mr. Mulhern) between the market median and the seventy-fifth percentile of compensation paid to similarly situated executives of the companies comprising the peer group. The compensation committee determined that the level of 2014 total direct compensation for our Named Executive Officers (including Mr. Mulhern) was appropriate based on an analysis of our peer group's total direct compensation and other market data that our compensation committee deemed relevant.

A significant percentage of total compensation for our Named Executive Officers is allocated to equity awards as a result of our compensation philosophy described above. Restricted stock awards with significant vesting and other conditions and performance-based RSUs with significant vesting conditions are aimed at ensuring that those executives remain with the Company and are incentivized over a long-term horizon to maximize shareholder value. In addition, the compensation committee considers the

Company’s historical burn rate when determining what restricted stock awards and performance-based RSUs are appropriate. The Company’s three-year average burn rate (using ISS’ methodology) was approximately 1.6%.

There is no pre-established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation for our executive officers. Rather, the compensation committee relies on each committee member’s knowledge and experience as well as information provided by management and the outside consultant to determine the appropriate level and mix of compensation.

Executive Compensation Components

Our executive compensation program consists of various elements of compensation that are intended to work together to provide total compensation that attracts, retains and motivates highly qualified and experienced individuals, ensures that a significant portion of their total compensation is “at risk” in the form of equity compensation and that such compensation represents a competitive compensation package that is consistent with our core values. For the fiscal year ended December 31, 2014, the principal components of compensation for Named Executive Officers were:

- base salary;
- performance-based cash bonus under the 2014 Management Incentive Plan;
- long-term incentive compensation;
- retirement and other benefits; and
- perquisites and other personal benefits.

Base Salary

We provide Named Executive Officers with a base salary to compensate them for services rendered during the fiscal year. Base salary ranges for Named Executive Officers are determined for each executive based on his position and responsibility by using market and other data that our compensation committee deems relevant.

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

- market data provided by our outside consultant;
- internal review of the executive’s compensation, both individually and relative to other officers;
- individual performance of the executive;
- performance of the executive’s department or functional unit;
- our operational performance, with respect to our production, reserves, finding and operating costs, drilling results, risk management activities and asset acquisitions;
- our financial performance, with respect to our cash flow, net income, cost of capital, general and administrative costs and common stock price performance;
- our overall competitive position and outlook relative to our industry;
- level of responsibility; and
- leadership ability, demonstrated commitment to the organization, motivational skills, attitude and work ethic.

Executive base salary levels are typically reviewed annually by our compensation committee and thereafter during the year if significant changes are made in an executive’s duties or responsibilities. In December 2012, the compensation committee reviewed the annual base salaries for our Named Executive Officers and decided not to make any changes for fiscal 2013. During 2013, the compensation committee increased the base salary of Mr. Hickey to $750,000 in connection with his increased duties and responsibilities upon being appointed our president on February 28, 2013. During 2014, the compensation committee increased Mr. Burnett’s base salary to $475,000 in connection with his appointment as chief financial officer effective September 19, 2014, but did not make any other changes to the base salaries for our other Named Executive Officers (including Mr. Mulhern). The compensation committee has determined not to make any changes to the base salary levels of our Named Executive Officers for 2015.

Cash Bonus

Prior to 2013, we typically paid year-end discretionary cash bonuses to each of our Named Executive Officers based on the Company's performance during the year and an analysis by our compensation committee of our peer group's total cash compensation and other market data. The payment of any cash bonus to Named Executive Officers was approved by our compensation committee, whose determination was historically based on the overall success of our company and not as a result of any particular financial, operational or individual performance criteria or target.

2013 Management Incentive Plan. On February 28, 2013, our board of directors adopted the 2013 Management Incentive Plan to replace our historical year-end discretionary cash bonuses for our officers, including our Named Executive Officers. The 2013 Management Incentive Plan created an annual incentive pool for the calendar year beginning January 1, 2013 and ending on December 31, 2013 for our Named Executive Officers (including Mr. Mulhern) and certain other officers based on achievement of certain performance measures and the discretion of the compensation committee. In fiscal 2013, we achieved the threshold goal for three of the five performance measures of the Company and the compensation committee's determination with respect to the discretionary portion of the incentive pool was based primarily on management's execution of the Company's strategic goals during 2013. The compensation committee had the authority to determine the amounts of the individual awards to eligible employees under the 2013 Management Incentive Plan. The compensation committee approved the payment of the following individual cash bonus awards to our Named Executive Officers under the 2013 Management Incentive Plan.

Name	2013 Management Incentive Plan Bonus
Harold L. Hickey	$ 240,000
William L. Boeing	$ 160,000
Mark F. Mulhern	$ 180,000

For additional information concerning the achievement of certain performance measures and the calculation of the incentive pool under the 2013 Management Incentive Plan, see "Compensation Discussion and Analysis—Executive Compensation Components—Cash Bonus—2013 Management Incentive Plan" in our Definitive Proxy Statement filed with the SEC on April 7, 2014.

2014 Management Incentive Plan. In April 2014, the board of directors adopted a new performance-based cash bonus plan with an initial performance period that began on January 1, 2014 and ended on December 31, 2014 (the "Performance Period"). The purpose of the 2014 Management Incentive Plan is to attract and retain the Company's management team and to encourage them to remain with, and devote their best efforts to, the Company and to reward them for outstanding performance, thereby advancing the interests of the Company and aligning management's interests with those of the Company's shareholders.

The compensation committee administers, interprets and makes determinations under, the 2014 Management Incentive Plan. For the Performance Period, the compensation committee determined that the Named Executive Officers and certain other officers were eligible for awards under the 2014 Management Incentive Plan. In addition, the compensation committee established the following performance measures as the basis for the awards under the 2014 Management Incentive Plan for the Performance Period: production, adjusted EBITDA and general and administrative costs. In addition, the compensation committee set the threshold achievement, target achievement and maximum achievement levels for each performance measure that is described in further detail below.

Each award has two components: sixty percent (60%) of an award is based on the achievement of the three performance measures and the remaining forty percent (40%) is determined in the sole discretion of the compensation committee. For the Performance Period, the compensation committee established a payout schedule that varies among the participants and is based on a percentage of the participant's base salary (the "award amount"). Sixty percent of the award amount was paid based on the Company's overall performance level, which is the sum of the weighted actual achievement of the performance goals for each performance measure in the Performance Period. Achievement of the performance goals was calculated on the basis of straight-line interpolation between the threshold achievement, target achievement and maximum achievement levels of each performance measure. The remaining forty percent (40%) of the award amount was paid based on the sole discretion of the compensation committee.

The 2014 Management Incentive Plan also includes provisions relating to the effect of a change in control of the Company as defined in the 2014 Management Incentive Plan or a participant's termination of employment.

For the Performance Period, each Named Executive Officer was entitled to an award based on the following performance measures and performance goals. The target goals below represented the midpoints of the Company's guidance for 2014. The fiscal 2014 performance targets and actual results for the performance measures of the Company taking into account acquisitions and dispositions during 2014 are set forth below:

Performance Measures	Weight	Threshold	Target	Maximum	Actual Performance
Production (Mcfe) (1)	20%	132,700	140,200	147,600	135,740
Adjusted EBITDA (dollars in millions) (2)	20%	$ 387.6	$ 409.9	$ 430.3	$ 391.2
General and administrative costs (dollars in millions) (3)	20%	$ 73.1	$ 69.6	$ 66.1	$ 61.0
Discretion of the compensation committee	40%				

(1) Production represents the net interest volumes of oil, natural gas and natural gas liquids stated on a Mcfe basis.
(2) Adjusted EBITDA means earnings before interest, taxes, depreciation, depletion, amortization, ceiling test write-downs, unrealized gains or losses on derivative financial instruments and other non-cash income and expense items.
(3) General and administrative costs represents expenses relating to the payment of employee compensation and benefits (other than equity and equity-based compensation), rent for office space, audit, legal, consulting and other professional fees, 2014 Management Incentive Plan systems and overhead costs, and such other "general and administrative costs," as determined under our standard accounting procedures and reported in our audited financial statements (reported net of overhead amounts reimbursed to us by working interest owners and joint venture partners, and net of amounts that are capitalized), but not including such expenses associated with the acquisition, exploration, exploitation, development, production or operation of our oil and gas properties.

Once the overall performance level was determined, the maximum award amounts for the Named Executive Officers were determined using the following payout schedule:

	Performance Level Payout Schedule			
	Percentage of Base Salary for Below Threshold Level Performance	Percentage of Base Salary for Threshold Level Performance	Percentage of Base Salary for Target Level Performance	Percentage Base Salary for Maximum Level Performance
Harold L. Hickey	0%	45%	90%	180%
William L. Boeing	0%	45%	90%	180%
Richard A. Burnett	0%	40%	80%	160%

During 2014, our Named Executive Officers were instrumental in arranging and carrying out significant transactions to enhance the Company's liquidity, including an equity offering, a debt offering and refinancing transaction and the sale of certain non-core assets and our interest in Compass. As a result of these transactions, the Company reduced its total debt by approximately $460 million in order to maintain greater financial flexibility to face the challenges associated with the current low commodity price environment and plan for future growth. The compensation committee approved the payment of the following individual cash bonus awards to our Named Executive Officers under the 2014 Management Incentive Plan, which were paid on March 13, 2015. Mr. Mulhern did not receive a cash bonus or any other benefits under the 2014 Management Incentive Plan since he resigned prior to the end of the Performance Period under the 2014 Management Incentive Plan.

Name	2014 Management Incentive Plan Bonus
Harold L. Hickey	$ 612,225
Richard A. Burnett	$ 296,891
William L. Boeing	$ 408,150

Long-Term Incentive Compensation

Incentive Plan. In many cases over the last several years, incentives granted under the Incentive Plan comprise the largest portion of our Named Executive Officers' total compensation package. As a result, a significant portion of compensation is "at risk" and tied to the performance of the Company. The Incentive Plan was originally adopted and approved by the board of directors of our predecessor entity in September 2005 and ultimately assumed by us. Over the years, with shareholder approval, we have increased the number of shares of common stock authorized for issuance under the Incentive Plan. Currently, the number of shares authorized for issuance under the Incentive Plan is 45,500,000 shares and each share granted that is subject to a full-value award will count as 1.74 shares against the total number of remaining shares we have reserved for issuance under the Incentive Plan. The term of the Incentive Plan will expire on February 28, 2023. The stated purpose of the Incentive Plan is to provide financial incentives to selected employees and to promote our long-term growth and financial success by:

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

Another important objective of our long-term incentive compensation is to strengthen the relationship between the long-term value of the price of our common stock and the potential financial gain for employees. Our compensation committee administers the Incentive Plan and the awards granted under the Incentive Plan. Awards under the Incentive Plan can consist of incentive stock options, non-qualified stock options, restricted stock, RSUs, stock appreciation rights and other awards. Until we began using restricted stock with significant vesting periods in August 2011, we had previously only used stock options under the Incentive Plan as incentives for our employees. In 2014, we implemented the use of performance-based RSUs and continued our philosophy of using restricted stock with significant vesting periods as an incentive for our officers and other selected employees primarily because we believed:

- restricted stock awards and performance-based RSUs help ensure that a significant portion of selected employees' total compensation is "at risk";
- restricted stock awards and performance-based RSUs are designed to allow selected employees to acquire a direct ownership interest in us over time and therefore be fully aligned with our shareholders;
- restricted stock awards and performance-based RSUs with vesting conditions tied to the price of our common stock align the interest of our officers with our shareholders;
- restricted stock awards are designed to be less vulnerable than stock options to volatility in our stock price, which is often impacted by volatile swings in the price of natural gas, and therefore serve as a more meaningful long-term retention vehicle even if our stock price decreased in the short-term; and
- based on market data provided by our outside compensation consultant, awarding restricted stock and performance-based RSUs would allow the Company to offer similar incentives to those companies with whom we compete for skilled talent since most of the companies in our peer group issue restricted stock or RSUs as part of their executive compensation incentives.

Previous awards and grants of stock options, restricted stock or RSUs, whether vested or unvested, generally do not have a significant impact on the current year's awards and grants unless otherwise considered by our compensation committee.

Restricted Stock Grants. Restricted stock consists of shares of common stock that may not be sold, transferred, pledged, hypothecated, encumbered or otherwise disposed of, and that may be forfeited in the event of certain terminations of employment or service, prior to the end of a restricted period specified by the compensation committee. Restricted stock awards with significant vesting periods and other conditions help ensure that those individuals remain with the Company and are incentivized over a long-term horizon to maximize shareholder value. Pursuant to the terms of the restricted stock award agreements, the shares of restricted stock granted:

- on September 2, 2014 to Mr. Burnett in connection with his appointment as Chief Financial Officer vest over a three year period in equal portions beginning on the first anniversary of the grant date, such that 1/3 of the shares vest on the first anniversary of the grant date, 1/3 of the shares vest on the second anniversary of the grant date and 1/3 of the shares vest on the third anniversary of the grant date;

- on July 1, 2014 to each of our Named Executive Officers (including Mr. Mulhern) vest over a three year period in equal portions beginning on the first anniversary of the grant date, such that 1/3 of the shares vest on the first anniversary of the grant date, 1/3 of the shares vest on the second anniversary of the grant date and 1/3 of the shares vest on the third anniversary of the grant date;
- on August 13, 2013 in two separate restricted stock awards to certain of our Named Executive Officers (including Mr. Mulhern) and selected other officers were subject to a performance vesting schedule based upon the first trading day immediately following the date that the fair market value of a share of our common stock equals or exceeds $10.00 in one grant and $15.00 in the other grant during any thirty (30) consecutive trading day period (the "Attainment Date"). The shares of restricted stock vest as follows: (i) if the Attainment Date occurs on or before the first anniversary of the grant date, 50% of the shares vest on the first anniversary of the grant date and the remaining 50% vest on the second anniversary of the grant date; (ii) if the Attainment Date occurs after the first anniversary of the grant date but before the second anniversary of the grant date, 50% of the shares vest on the Attainment Date and the remaining 50% vest on the second anniversary of the grant date; (iii) if the Attainment Date occurs after the second anniversary of the grant date but before the fifth anniversary of the grant date, 100% of the shares vest on the Attainment Date, in each case, provided the applicable Named Executive Officer is employed by or providing services to the Company or a subsidiary on such date;
- on April 1, 2013 to Mr. Mulhern in connection with the commencement of his employment as our executive vice president and chief financial officer were scheduled to vest over a three year period in equal portions beginning on the first anniversary of the grant date, such that 1/3 of the shares vested on the first anniversary of the grant date while the remaining shares were forfeited back to the Company in connection with Mr. Mulhern's resignation;
- on December 13, 2012 to certain of our Named Executive Officers and other selected officers and employees, vest over a three year period in equal portions beginning on the first anniversary of the grant date, such that 1/3 of the shares vested on the first anniversary of the grant date, 1/3 of the shares vested on the second anniversary of the grant date and 1/3 of the shares are scheduled to vest on the third anniversary of the grant date; and
- on November 21, 2011 to certain of our Named Executive Officers and selected officers, vest over a five year period with 60% of these shares having vested on the third anniversary of the grant date, 20% of these shares vesting on the fourth anniversary of the grant date and 20% of these shares vesting on the fifth anniversary of the grant date; and
- become fully vested, subject to their early termination as provided in the restricted stock award agreements, immediately prior to a change of control of us or upon the death or disability of the holder as defined in the Incentive Plan.

Effective July 1, 2014, the compensation committee granted a total of 781,254 shares of restricted stock to a select group of employees, which included our Named Executive Officers and Mr. Mulhern, based on a target percentage of such employee's annual base salary approved by the compensation committee at the time of the grant, pro rata for any partial year of service. Effective September 2, 2014, the compensation committee granted an additional 139,063 shares of restricted stock to Mr. Burnett in connection with his appointment as Chief Financial Officer. Under the terms of the Incentive Plan at the time of the grants, each share of restricted stock granted counted as 1.74 shares against the total number of remaining shares we have reserved for issuance under the Incentive Plan, subject to future forfeitures of unvested shares prior to the applicable vesting dates, such that 1,601,352 shares were deemed to have been granted under the Incentive Plan.

The table below summarizes shares of restricted stock issued under the Incentive Plan to each of the Named Executive Officers (including Mr. Mulhern) during 2014, 2013 and 2012:

Named Executive Officer	**Restricted Stock Awarded in 2014**	**Restricted Stock Awarded in 2013**	**Restricted Stock Awarded in 2012**
Harold L. Hickey	104,167	97,600	20,800
Richard A. Burnett	178,126(1)	85,000(2)	—
William L. Boeing	104,167	48,800	23,100
Mark F. Mulhern(3)	104,167	173,200	—

(1) The compensation committee issued, effective September 2, 2014, a total of 139,063 shares of restricted stock to Mr. Burnett in connection with his appointment as our Chief Financial Officer.
(2) Represents shares of restricted stock granted to Mr. Burnett in connection with his commencement of employment with the Company.
(3) All shares of restricted stock issued to Mr. Mulhern during 2014 and the unvested portion of the shares of restricted stock issued to Mr. Mulhern in 2013 were forfeited in connection with his resignation, effective September 19, 2014.

Restricted Stock Units. RSUs consist of equity awards that convert into shares of our common stock upon the achievement of either time-based or performance-based vesting conditions. RSUs with significant performance-based vesting conditions help ensure that individuals remain with EXCO and are incentivized over a long-term horizon to maximize shareholder value. The compensation committee granted 104,167 performance-based RSUs to each of Messrs. Hickey, Mulhern and Boeing on July 1, 2014, 39,063 performance-based RSUs to Mr. Burnett on July 1, 2014 and an additional 39,063 performance-based RSUs to Mr. Burnett on September 2, 2014 in connection with his appointment as our Chief Financial Officer. Mr. Mulhern forfeited all of his performance-based RSUs in connection with his resignation from the Company.

The RSU award agreement provides that a participant is eligible to vest in and receive a number of shares of the common stock ranging from 0% to 200% of the target number of RSUs granted based on the attainment of total shareholder return ("TSR") goals during the period commencing on and including the date of grant and ending on third anniversary of the date of grant (the "Measurement Period"). The RSUs will vest upon the third anniversary of the date of grant, July 1, 2017 (the "Vesting Date"), subject to the achievement of certain performance criteria set forth below, provided that the participant is providing services to the Company or a subsidiary on that date and subject to the restrictions and conditions of the Incentive Plan.

The number of RSUs that vest and convert into shares of our common stock is dependent upon the Company's TSR achieved during the Measurement Period relative to the TSR achieved during the Measurement Period by the Company's peer group determined by the compensation committee. Each vested RSU will convert into one share of our common stock. If the percentile rank of the Company's TSR within the peer group is below 35%, then no RSUs will vest. If the percentile rank of the Company's TSR equals 35%, then 50% of the target RSUs will vest, and for every increase in the Company's percentile rank within the peer group over 35%, a proportionate percentage of target RSUs will vest on the Vesting Date (i.e., if the percentile rank of the Company's TSR is between 35%-49% of the peer group, then 50%-99% of target RSUs will vest; if the percentile rank of the Company's TSR is between 50%-74% of the peer group, then 100%-199% of target RSUs will vest; and if the percentile rank of the Company's TSR is 75% of the peer group or above, then 200% of target RSUs will vest) and convert into shares of our common stock (calculated on the basis of straight-line interpolation applied on the change in performance between threshold and target, and between target and maximum levels of percentile rank). In addition, all unvested RSUs become immediately vested and convert into shares of our common stock upon a change in control based on the achievement of the performance criteria determined as of the closing date of the change in control as defined in the Incentive Plan; provided that the participant is employed by or providing services to the Company as of the change in control. Unvested RSUs are forfeited upon the earliest of (i) the Vesting Date and (ii) the participant's termination of service, provided that if such termination of service is due to death or disability, such participant is treated as continuing to provide services during the Measurement Period.

Stock Option Grants. A stock option becomes valuable only if the price of our common stock increases above the option exercise price and the holder of the option remains employed during the period required for the option to "vest," thus providing an incentive for an option holder to remain our employee. In addition, stock options link a portion of an employee's compensation to shareholders' interests by providing an incentive to increase the market price of our common stock. All options are awarded with an exercise price equal to the closing price of our common stock on the NYSE on the date of the grant. The compensation committee has never granted options with an exercise price that is less than the closing price of our common stock on the grant date, nor has it granted options that have an exercise price based on a date other than the grant date.

Pursuant to the terms of our stock option agreements, the stock options granted:

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

We granted stock option bonuses in August 2013 to selected employees, including Messrs. Hickey, Boeing and Mulhern, based on a target percentage equal to between 55% and 125% of such employee's annual base salary approved by the compensation committee at the time of the grant, pro rata for any partial year of service, multiplied by such person's base salary and then divided by a Black-Scholes grant date valuation. Based on this formula, we granted stock options with an exercise price equal to $7.68 per share to the Named Executive Officers in August 2013 as set forth in the table below. All of Mr. Mulhern's stock options set forth in the table below were forfeited back to the Company following his resignation. We did not grant any stock options to the Named Executive Officers during 2014.

Name	Base Salary	Grant Date Fair Value	2013 Stock Options
Harold L. Hickey	$ 750,000	$ 752,905	204,900
Mark F. Mulhern	$ 750,000	$ 564,771	153,700
William L. Boeing	$ 500,000	$ 376,636	102,500

Historical Long-Term Incentive Grants. The following table shows the number of our employees as of December 31st of each year set forth below, the number of stock options granted to new hires, the number of stock options granted as an annual incentive bonus and the number of shares of restricted stock and performance-based RSUs granted (excluding the effect of the applicable fungible share ratio) during each of the years set forth below.

	2014	2013	2012
Number of Employees	558	755	919
Stock Option Awards to New Hires	141,525	577,000	106,500
Annual Option Bonus Awards	—	2,269,500	—
Restricted Stock Awards(1)	1,339,782	1,292,700	926,900
RSU Awards(1)	820,317	—	—

(1) The shares of restricted stock issued in 2012, 2013 and 2014 and the number of performance-based RSUs granted in 2014 resulted in a reduction of 1,946,490 shares, 2,285,298 shares and 5,185,924 shares, respectively, available for issuance under the Incentive Plan due to the effect of the applicable fungible share ratios (subject to any forfeitures of unvested shares prior to the applicable vesting dates).

Stock Ownership Guidelines. We do not have formal stock ownership guidelines. However, our executive officers are encouraged to maintain or establish a significant level of direct stock ownership.

Hedging Policies. Pursuant to our insider trading policy, we discourage our directors, officers, employees and consultants (collectively, "insiders") from engaging in transactions pursuant to which such persons would hedge the economic ownership of our securities. Under the insider trading policy, insiders are prohibited from engaging in short sales of our securities and in transactions in publicly traded options, are subject to limitations on standing orders and are discouraged from placing our securities in a margin account or being pledged as collateral.

Retirement and Other Benefit Plans

401(k) Plan. All of our employees are eligible to participate in the EXCO Resources, Inc. 401(k) Plan. While the amount of the matching contribution under the 401(k) plan is discretionary, in recent years we have matched 100% of employee contributions to the 401(k) plan up to the Internal Revenue Service limit with vesting of Company matching contributions based on years of service with us.

Severance Plan. The Fourth Amended and Restated Severance Plan (the "Severance Plan") is applicable to all of our employees in the event of a change of control. The Severance Plan provides for the payment of severance equal to 1.25 times an employee's annual base salary in the event the employee's employment is terminated or there is an adverse change in the employee's job or compensation within twelve months following a change of control, as defined in the Severance Plan. For more information about the Severance Plan, see "—Compensation of Executive Officers—Potential Payments Upon Termination or Change-in-Control."

Other Benefits Plans. We offer a variety of health and benefit programs to all employees, including medical, dental, vision, life insurance and disability insurance. Our Named Executive Officers (including Mr. Mulhern during his employment with us) are generally eligible to participate in these employee benefit plans on the same basis as the rest of our employees. During 2014, we also provided physical exams for our Named Executive Officers.

Retention Agreements

On January 17, 2014, we entered into a separate Bonus and Retention Agreement with each of Messrs. Hickey, Mulhern and Boeing (collectively, the "Bonus and Retention Agreements") in order to retain and incentivize them to continue providing services to the Company in light of the resignation of the Company's former chief executive officer and the board of directors' search process for a replacement chief executive officer. In addition, in connection with Mr. Burnett's appointment as Chief Financial Officer, we entered into a Retention Agreement with Mr. Burnett, effective as of September 1, 2014 (the "Burnett Retention Agreement" and, collectively with the Bonus and Retention Agreements, the "Retention Agreements"), in order to retain and incentivize Mr. Burnett to continue providing services to the Company. Mr. Mulhern's Retention Agreement terminated in all respects effective September 19, 2014 in connection with his resignation from the Company.

Retention Bonus. Pursuant to the terms of the Retention Agreements, each of Messrs. Hickey, Mulhern and Boeing received a cash payment on June 30, 2014 equal to fifty percent (50%) of their base salary (the "Retention Bonus"), or $375,000, $375,000 and $250,000, respectively. The Burnett Retention Agreement does not provide for the payment of a Retention Bonus.

Burnett Initial Severance Benefits. If Mr. Burnett's employment is terminated by the Company without "cause" or he terminates his employment for "good reason" (collectively, a "Qualifying Termination") during the period (the "Initial Severance Period") beginning on September 1, 2014 and ending on the day immediately prior to the first day of the Special Severance Period (as defined below), he is entitled to receive, subject to certain exceptions, the following severance benefits (the "Initial Severance Benefits"):

- A cash payment equal to one (1) times Mr. Burnett's annual base salary (less applicable income and employment tax withholdings), fifty percent (50%) of which will be paid on the sixtieth (60th) day following Mr. Burnett's Qualifying Termination and fifty percent (50%) of which will be paid on the one (1) year anniversary of Mr. Burnett's Qualifying Termination; and
- COBRA benefits for up to twelve (12) months following Mr. Burnett's Qualifying Termination.

Special Severance Benefits. The Retention Agreements provide for certain benefits upon a Qualifying Termination of Messrs. Hickey, Boeing and Burnett during the period (the "Special Severance Period") beginning on the date that a new person (other than a person who was employed by the Company as of the date of the applicable Retention Agreement) is hired as the chief executive officer of the Company (the "Commencement Date") and ending on the earlier of (A) the effective date of a Change of Control or (B) the date that is two years following the Commencement Date. The severance benefits (the "Special Severance Benefits") provided during the Special Severance Period include the following:

- A cash payment equal to two (2) times such executive's base salary (less applicable income and employment tax withholdings), fifty percent (50%) of which will be paid on the sixtieth (60th) day following such executive's Qualifying Termination and fifty percent (50%) of which will be paid on the one (1) year anniversary of such executive's Qualifying Termination;
- COBRA benefits for up to eighteen (18) months following such executive's Qualifying Termination;
- Accelerated vesting of any unvested restricted stock awards with time-based vesting to the date of the Qualifying Termination;
- Extension of the exercise period for any vested stock options for one (1) year following the date of such executive's Qualifying Termination (or if earlier, the date the options would have expired if such executive had remained employed by the Company); and
- With respect to Mr. Burnett only, to the extent any performance-based RSUs granted by the Company to Mr. Burnett on July 1, 2014 (the "July PRSUs") are still outstanding and have not yet vested by the date of his Qualifying Termination, such July PRSUs shall not be forfeited upon such Qualifying Termination, and Mr. Burnett shall be treated as if is continuing to provide services for purposes of applying the vesting provisions set forth in the award agreement for such July PRSUs through July 1, 2017.

In order to receive any of the Initial Severance Benefits or Special Severance Benefits, as applicable, the executive must sign and return a release of claims, within thirty (30) days of a Qualifying Termination, and any applicable revocation period must have expired. Receipt of the Initial Severance Benefits or Special Severance Benefits, as applicable, is also contingent on such executive's continued compliance with certain confidentiality, non-disparagement and non-solicitation provisions contained in his Retention

Agreement. In the event that a Change of Control occurs prior to an executive's Qualifying Termination, no Initial Severance Benefits or Special Severance Benefits will be paid under the Retention Agreement, and such executive's right to severance payments, if any, shall be governed by the terms of the Severance Plan. Further, with respect to the Burnett Retention Agreement, no Special Severance Benefits are payable if his Qualifying Termination occurs during the Initial Severance Period; rather, Mr. Burnett would only be entitled to receive his Initial Severance Benefits.

Compensation Business Risk Review

While a significant portion of our annual cash bonus structure is based on the Company's achievement of specified operational and financial performance metrics, we have historically compensated our executive officers and other employees under a structure that is focused on overall company performance and is not based on the achievement of specified targets or milestones by any one individual, department or function. We believe this compensation structure protected the Company and its shareholders against excessive risk taking by individuals, departments or functions who may have otherwise been motivated to achieve a particular target or milestone even if the achievement of that objective would not necessarily have contributed to the overall success of the Company. For 2014, our board of directors adopted the 2014 Management Incentive Plan, which provided for annual cash bonuses to our executive officers based on the Company's achievement of certain performance criteria. In addition, we use restricted stock and RSU awards with significant vesting periods or conditions because we believe those types of awards incentivize our executive officers and other employees to achieve our long-term goal of maximizing shareholder value. Restricted stock or RSU awards with significant vesting periods or conditions help ensure that our executives remain with the Company and are incentivized over a long-term horizon to maximize shareholder value. The other elements of our compensation are comprised of typical benefit plans, such as a 401(k) plan and health, life and disability insurance. Accordingly, our compensation committee believes that our compensation policies and practices do not create unreasonable or inappropriate risks that are reasonably likely to have a material adverse effect on the Company.

Say-on-Pay Vote

In May 2014, we held a shareholder advisory vote to approve the compensation of our Named Executive Officers, commonly referred to as a say-on-pay vote. Our shareholders approved the compensation of our Named Executive Officers, with over 88% of shareholder votes cast in favor of our say-on-pay resolution. The compensation committee was mindful of this supportive say-on-pay vote when making its decisions regarding executive compensation for 2014. The compensation committee intends to take the say-on-pay votes into consideration in setting future compensation for our Named Executive Officers. We are mindful of the support our shareholders expressed for our compensation philosophy and the compensation committee remains committed to a focus on long-term incentive compensation as a strong incentive to reward our employees, including the Named Executive Officers, for achievement of strategic goals, and we will continue to consider shareholder concerns and feedback in the future. We intend to conduct an advisory vote to approve executive compensation on an annual basis until the next advisory vote to determine the frequency of future advisory votes on such compensation.

Tax and Accounting Implications

Deductibility of Executive Compensation

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

Nonqualified Deferred Compensation

On October 22, 2004, the American Jobs Creation Act of 2004 was signed into law, changing the tax rules applicable to nonqualified deferred compensation arrangements. We believe that we are operating in compliance with the final regulations that became effective January 1, 2009.

Accounting for Share-Based Compensation

Our predecessor adopted the provisions of ASC Topic 718 upon its formation in August 2005. Upon the closing of a series of mergers in connection with our initial public offering in February 2006, we adopted ASC Topic 718.

Compensation Committee Report

Our compensation committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the compensation committee recommended to our board of directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

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

COMPENSATION COMMITTEE*
Robert L. Stillwell, Chairman
Jeffrey D. Benjamin
B. James Ford
Samuel A. Mitchell**
Wilbur L. Ross, Jr.
Jeffrey S. Serota

* Mr. Mulhern resigned from the compensation committee on February 28, 2013.

** Mr. Mitchell was appointed to the compensation committee on September 10, 2013 and therefore did not participate in setting executive compensation for the fiscal 2012 year.

Compensation of Executive Officers

The total compensation paid to our chief executive officer and president and former chief operating officer, Harold L. Hickey, our chief financial officer, Richard A. Burnett, our former chief financial officer, Mark F. Mulhern, and William L. Boeing, our vice president, general counsel and secretary is set forth in the following Summary Compensation Table. For purposes of this section, references to Named Executive Officers include Mr. Mulhern.

2014, 2013 AND 2012 SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	Stock Awards ($)(2)	Option Awards ($)(3)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)(4)	Total ($)
Harold L. Hickey(5)	2014	750,000	987,225	1,365,629	—	—	—	23,000	3,125,854
Chief Executive Officer	2013	656,250	465,000	621,224	752,905	—	—	23,000	2,518,379
and President and Former Chief Operating Officer	2012	450,000	362,500	157,456	—	—	—	22,500	992,456
Richard A. Burnett(6) .... *Vice President, Chief Financial Officer and Chief Accounting Officer*	2014	409,167	296,891	1,449,263	—	—	—	17,500	2,172,821
Mark F. Mulhern(7)..........	2014	534,135	375,000	1,365,629	—	—	—	23,000	2,297,764
Former Executive Vice President and Chief Financial Officer	2013	562,500	380,000	1,159,918	1,198,411	—	—	32,246	3,333,075
William L. Boeing............	2014	500,000	658,150	1,365,629	—	—	—	23,000	2,546,779
Vice President,	2013	500,000	410,000	310,612	376,636	—	—	23,000	1,620,248
General Counsel and Secretary	2012	500,000	325,000	174,867	—	—	—	22,500	1,022,367

(1) Bonus column for 2013 includes the cash amount paid in March 2014 pursuant to the 2013 Management Incentive Plan. Bonus column for 2014 includes a cash retention bonus paid pursuant to the Retention Agreements on June 30, 2014 equal to fifty percent (50%) of base salary for each of Messrs. Hickey, Mulhern and Boeing, or $375,000, $375,000 and $250,000, respectively, and the cash bonus amount paid in March 2015 pursuant to the 2014 Management Incentive Plan.

(2) This column represents the aggregate grant date fair value of shares of restricted stock issued to each Named Executive Officer in 2014, 2013 and 2012 in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 718—Compensation—Stock Compensation ("ASC 718"), with the exception that the amount shown assumes no forfeitures. Assumptions used in the calculation of these amounts are included in "Note 2. Summary of significant accounting policies—Share-based compensation" and "Note 11. Stock options and awards" to our audited financial statements for the fiscal year ended December 31, 2014 included in this Annual Report on Form 10-K.

(3) This column represents the aggregate grant date fair value of stock options granted to each Named Executive Officer in 2014, 2013 and 2012 in accordance with ASC Topic 718, with the exception that the amount shown assumes no forfeitures. Assumptions used in the calculation of these amounts are included in "Note 2. Summary of significant accounting policies—Share-based compensation" and "Note 11. Stock options and awards" to our audited financial statements for the fiscal year ended December 31, 2014 included in this Annual Report on Form 10-K.

(4) The amounts shown in this column reflect, for each Named Executive Officer, matching contributions allocated by us to each of the Named Executive Officers pursuant to the EXCO Resources, Inc. 401(k) Plan as follows: Mr. Hickey—$23,000; Mr. Burnett—$17,500; Mr. Mulhern—$23,000; and Mr. Boeing—$23,000 for 2014; Mr. Hickey—$23,000; Mr. Mulhern—$23,000; and Mr. Boeing—$23,000 for 2013; and Mr. Hickey—$22,500; and Mr. Boeing—$22,500 for 2012. We maintained a suite at the Rangers Ballpark in Arlington, Texas during 2012, 2013 and 2014 and a suite at the American Airlines Center in Dallas, Texas during 2012 and 2013 for sporting events and other entertainment purposes. We have not included any amounts related to the suites as a perquisite because tickets to the suites are available to all of our employees on a non-discriminatory basis, with business entertainment purposes having priority as to use. We no longer maintain either of those suites.

(5) Mr. Hickey became our Chief Executive Officer effective March 30, 2015. Mr. Hickey served as our Chief Operating Officer from October 2005 until March 2015.

(6) Mr. Burnett became our Chief Financial Officer effective September 19, 2014. In connection with the appointment as Chief Financial Officer, Mr. Burnett received 139,063 shares of restricted stock.

(7) Mr. Mulhern became our Executive Vice President and Chief Financial Officer on April 1, 2013. In connection with the commencement of his employment, Mr. Mulhern received a sign-on bonus equal to $200,000 and 100,000 shares of restricted stock and a stock option to purchase 200,000 shares. Mr. Mulhern resigned from his positions as Executive Vice President and Chief Financial Officer, effective September 19, 2014. Mr. Mulhern forfeited all of his unvested shares of restricted stock, restricted stock units and stock options and did not receive any severance or other benefits in connection with his resignation from the Company.

See "—Compensation Discussion and Analysis—Executive Compensation Components—Base Salary" for a discussion of the 2015 base salaries of our Named Executive Officers.

2014, 2013 AND 2012 REALIZED COMPENSATION TABLE

The following table supplements the Summary Compensation Table set forth under "—Compensation of Executive Officers" above. This table shows the compensation actually realized in the fiscal years ended December 31, 2014, 2013 and 2012 by our Named Executive Officers. We have included the Realized Compensation Table to better show how our equity compensation drives actual or "realized" compensation. The primary difference between this supplemental table and the Summary Compensation Table is the method used to value equity awards. SEC rules require companies to report the grant date fair value of all equity awards in the Summary Compensation Table for the year for which they were granted. As a result, a significant portion of the total compensation amounts reported in the Summary Compensation Table related to equity grants that have not yet vested and for which the value is consequently uncertain. In contrast, the supplemental table below includes only (i) the value of restricted stock awards that vested during the applicable fiscal year as of the applicable vesting date, (ii) the value of shares of performance-based restricted stock actually vested based on a performance threshold being met for the performance period ending in the applicable fiscal year and (iii) the value of performance-based RSUs actually vested based on a performance threshold being met for the performance period ending in the applicable fiscal year. The supplemental table below also includes only stock options that were exercised during the applicable fiscal year and shows the value of those awards as of the applicable exercise date. It should be noted that there is no assurance that the Named Executive Officers will actually realize the value attributed to the restricted stock and RSU awards even in this supplemental table, since the value of the restricted stock and RSU awards will depend on when the common stock underlying such awards is sold.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(1)	Stock Awards Value Realized ($)(2)	Option Value Realized ($)(3)	All Other Compensation ($)(1)	Total Realized Compensation ($)
Harold L. Hickey(4)	2014	750,000	987,225	311,122	—	23,000	2,071,347
Chief Executive Officer and	2013	656,250	465,000	73,560	—	23,000	1,217,810
President and Former Chief	2012	450,000	362,500	38,391	—	22,500	873,391
Operating Officer							
Richard A. Burnett(5)	2014	409,167	296,891	74,516	—	17,500	798,074
Vice President, Chief Financial Officer and Chief Accounting Officer							
Mark F. Mulhern(6)	2014	534,135	375,000	185,670	—	23,000	1,117,805
Former Executive Vice President	2013	562,500	380,000	—	—	32,246	974,746
and Chief Financial Officer							
William L. Boeing	2014	500,000	658,150	343,760	—	23,000	1,524,910
Vice President, General Counsel	2013	500,000	410,000	81,650	—	23,000	1,014,650
and Secretary	2012	500,000	325,000	42,604	—	22,500	890,104

(1) The amount shown in this column for each Named Executive Officer, if any, is identical to the amount set forth in the corresponding column in the "Summary Compensation Table" above.

(2) This column represents the value, as of the applicable vesting date, of the shares of restricted stock that vested during the applicable fiscal year, calculated by multiplying the number of shares of restricted stock vested by the closing price on the vesting date. This column does not include (i) the value of shares of performance-based restricted stock because our performance did not reach threshold levels during the applicable year or (ii) the value of performance-based RSUs because the performance period did not end during the applicable fiscal year.

(3) This column represents the aggregate value of all stock options that were exercised during the applicable fiscal year. The value of exercised stock options is calculated by multiplying the number of options exercised by the difference between the exercise price and the closing price of our common stock on the exercise date.

(4) Mr. Hickey became our Chief Executive Officer effective March 30, 2015. Mr. Hickey served as our Chief Operating Officer from October 2005 until March 2015.

(5) Mr. Burnett became our Chief Financial Officer effective September 19, 2014. In connection with the commencement of his appointment as our Chief Financial Officer, Mr. Burnett received 139,063 shares of restricted stock.

(6) Mr. Mulhern resigned from his positions as Executive Vice President and Chief Financial Officer, effective September 19, 2014. Mr. Mulhern forfeited all of his unvested shares of restricted stock, restricted stock units and stock options and did not receive any severance or other benefits in connection with his resignation from the Company.

Equity Incentive Awards

The following table sets forth information regarding the plan-based awards under the Incentive Plan granted to each Named Executive Officer (including Mr. Mulhern) during the fiscal year ended December 31, 2014:

2014 FISCAL YEAR GRANTS OF PLAN-BASED AWARDS

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units	All Other Option Awards: Number of Securities Underlying Options	Exercise or Base Price of Option Awards	Grant Date Fair Value of Stock and Option Awards
Name	**Grant Date**	**Threshold ($)**	**Target ($)**	**Maximum ($)**	**Threshold (#)**	**Target (#)**	**Maximum (#)**	**(#)**	**(#)**	**($ / Share)**	**($)(1)**
Harold L. Hickey......	7/1/2014	—	—	—	—	—	—	104,167(2)	—	—	602,086
	7/1/2014	—	—	—	—	—	—	104,167(3)	—	—	763,544
Richard A. Burnett......	7/1/2014	—	—	—	—	—	—	39,063(2)	—	—	225,784
	7/1/2014	—	—	—	—	—	—	39,063(3)	—	—	286,332
	9/2/2014	—	—	—	—	—	—	139,063(4)	—	—	650,815
	9/2/2014	—	—	—	—	—	—	39,063(5)	—	—	286,332
Mark F. Mulhern....	7/1/2014	—	—	—	—	—	—	104,167(2)(6)	—	—	602,085
	7/1/2014	—	—	—	—	—	—	104,167(3)(6)	—	—	763,544
William L. Boeing......	7/1/2014	—	—	—	—	—	—	104,167(2)	—	—	602,085
	7/1/2014	—	—	—	—	—	—	104,167(3)	—	—	763,544

(1) Represents the grant date fair value of the awards computed in accordance with ASC 718, with the exception that the amount shown assumes no forfeitures. Assumptions used in the calculation of these amounts are included in "Note 2. Summary of significant accounting policies—Share-based compensation" and "Note 11. Stock options and awards" to our audited financial statements for the fiscal year ended December 31, 2014 included in this Annual Report on Form 10-K.

(2) Represents shares of restricted common stock issued to the Named Executive Officer pursuant to a restricted stock award agreement dated July 1, 2014. The shares of restricted stock vest over a three year period in equal portions beginning on the first anniversary of the grant date, such that 1/3 of the shares vest on the first anniversary of the grant date, 1/3 of the shares vest on the second anniversary of the grant date and 1/3 of the shares vest on the third anniversary of the grant date, provided that the holder of the shares of restricted stock remains employed with us on that date. These shares of restricted stock are subject to forfeiture and other restrictions as more fully set forth in the Incentive Plan and the applicable restricted stock award agreement and are subject to accelerated vesting upon a change in control, death or permanent disability.

(3) Represents performance-based RSUs that will vest between 0% and 200% of the target number of RSUs on July 1, 2017 based on the Company's achievement of TSR relative to the TSR achieved by a peer group established by the compensation committee. These RSUs were issued pursuant to the Incentive Plan and an RSU award agreement dated as of July 1, 2014 and are subject to forfeiture, accelerated vesting and other restrictions as more fully set forth in the Incentive Plan and the RSU award agreement.

(4) Represents shares of restricted common stock issued to Mr. Burnett pursuant to a restricted stock award agreement dated September 2, 2014. The shares of restricted stock vest over a three year period in equal portions beginning on the first anniversary of the grant date, such that 1/3 of the shares vest on the first anniversary of the grant date, 1/3 of the shares vest on the second anniversary of the grant date and 1/3 of the shares vest on the third anniversary of the grant date, provided that Mr. Burnett remains employed with us on that date. These shares of restricted stock are subject to forfeiture and other restrictions as more fully set forth in the Incentive Plan and the restricted stock award agreement and are subject to accelerated vesting upon a change in control, death or permanent disability.

(5) Represents performance-based RSUs that will vest between 0% and 200% of the target number of RSUs on July 1, 2017 based on the Company's achievement of TSR relative to the TSR achieved by a peer group established by the compensation committee. These RSUs were issued to Mr. Burnett pursuant to the Incentive Plan and an RSU award agreement dated as of September 2, 2014 and are subject to forfeiture, accelerated vesting and other restrictions as more fully set forth in the Incentive Plan the RSU award agreement.

(6) The RSUs and shares of restricted stock granted to Mr. Mulhern during 2014 were forfeited pursuant to the terms of the restricted stock award agreement and the RSU award agreement in connection with his resignation, which was effective September 19, 2014.

See "—Compensation Discussion and Analysis—Executive Compensation Components—Long-Term Incentive Compensation—Incentive Plan" for a discussion of grants of plan-based awards made to our Named Executive Officers in 2014.

The following table sets forth information regarding the outstanding equity awards held by our Named Executive Officers (including Mr. Mulhern) as of December 31, 2014.

2014 FISCAL YEAR OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END

		Option Awards(1)					Stock Awards			
Name	Grant Date	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)(2)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(2)
Harold L. Hickey......	10/5/2005	166,700	—	—	7.50	10/4/2015	—	—	—	—
	12/1/2006	30,000	—	—	14.62	11/30/2016	—	—	—	—
	12/4/2007	35,000	—	—	13.72	12/3/2017	—	—	—	—
	12/11/2008	35,000	—	—	7.88	12/10/2018	—	—	—	—
	12/1/2009	35,000	—	—	17.60	11/30/2019	—	—	—	—
	12/7/2010	43,800	—	—	18.50	12/6/2020	—	—	—	—
	11/21/2011	—	—	—	—	—	48,087(3)	104,349	—	—
	12/13/2012	—	—	—	—	—	6,933(4)	15,045	—	—
	8/13/2013	102,450	102,450	—	7.68	8/12/2023	—	—	—	—
	8/13/2013	—	—	—	—	—	—	—	97,600(5)	211,792
	7/1/2014	—	—	—	—	—	104,167(6)	226,042		
	7/1/2014	—	—	—	—	—	—	—	52,084(7)	113,022
Richard A. Burnett	12/2/2013	62,500	62,500	—	5.17	12/1/2023	—	—	—	—
	12/2/2013	—	—	—	—	—	56,666(8)	122,965		
	7/1/2014	—	—	—	—	—	39,063(6)	84,767	—	—
	7/1/2014	—	—	—	—	—	—	—	19,532(7)	42,384
	9/2/2014	—	—	—	—	—	139,063(9)	301,767	—	—
	9/2/2014	—	—	—	—	—	—	—	19,532(10)	42,384
William L. Boeing......	4/5/2006	500,000	—	—	12.36	4/4/2016	—	—	—	—
	12/1/2006	26,200	—	—	14.62	11/30/2016	—	—	—	—
	12/4/2007	40,000	—	—	13.72	12/3/2017	—	—	—	—
	12/11/2008	40,000	—	—	7.88	12/10/2018	—	—	—	—
	12/1/2009	40,000	—	—	17.60	11/30/2019	—	—	—	—
	12/7/2010	48,700	—	—	18.50	12/6/2020	—	—	—	—
	11/21/2011	—	—	—	—	—	53,096(3)	115,218	—	—
	12/13/2012	—	—	—	—	—	7,700(4)	16,709	—	—
	8/13/2013	51,250	51,250	—	7.68	8/12/2023	—	—	—	—
	8/13/2013	—	—	—	—	—			48,800(5)	105,896
	7/1/2014	—	—	—	—	—	104,167(6)	226,042	—	—
	7/1/2014	—	—	—	—	—			52,084(7)	113,022

(1) Pursuant to the terms of the stock option agreements that we entered into with the Named Executive Officer, these options are vested as to 25% of the shares subject to the option on the date of grant and vest an additional 25% on each of the next three anniversaries of the date of grant provided that the holder of the option remains employed with us on that date. These options become fully vested and exercisable, subject to their early termination as provided in the option agreements, immediately prior to a change of control of us.

(2) Market value is based on $2.17 per share closing price of our common stock as reported on the NYSE as of December 31, 2014.

(3) Pursuant to the terms of the restricted stock award agreement that we entered into with the Named Executive Officer on November 21, 2011, the award vests over a five year period with 60% of the shares vesting on the third anniversary of the grant date, 20% of the shares vesting on the fourth anniversary of the grant date and 20% of the shares vesting on the fifth anniversary of the grant date, provided that the holder of the restricted stock award remains employed with us on that date. These shares become fully vested and exercisable, subject to their early termination as provided in the restricted stock award agreement, immediately prior to a change of control of us.

(4) Pursuant to the terms of the restricted stock award agreement that we entered into with the Named Executive Officer on December 13, 2012, the award vests in equal proportions over three years with one-third vesting on December 13, 2013, one-third vesting on December 13, 2014 and one-third vesting on December 13, 2015, provided that the holder of the restricted stock award remains employed with us on that date. These shares become fully vested and exercisable, subject to their early termination as provided in the restricted stock award agreement, immediately prior to a change of control of us.

(5) Represents shares of restricted stock issued to the Named Executive Officer in two separate restricted stock award agreements, each of which is dated as of August 13, 2013 and is subject to a performance vesting schedule based upon the Attainment Date. The "Attainment Date" means the first trading day immediately following the date that the fair market value of a share of our common stock equals or exceeds $10.00 for one award and $15.00 for the other award during any thirty (30) consecutive trading day period. The shares of restricted stock vest as follows: (i) if the Attainment Date occurs on or before the first anniversary of the grant date, 50% of the shares vest on the first anniversary of the grant date and the remaining 50% vest on the second anniversary of the grant date; (ii) if the Attainment Date occurs after the first anniversary of the grant date but before the second anniversary of the grant date, 50% of the shares vest on the Attainment Date and the remaining 50% vest on the second anniversary of the grant date; (iii) if the Attainment Date occurs after the second anniversary of the grant date but before the fifth anniversary of the grant date, 100% of the shares vest on the Attainment Date, in each case, provided the Named Executive Officer is employed by or providing services to the Company or a subsidiary on such date. These shares of restricted stock are subject to forfeiture and other restrictions as more fully set forth in the Incentive Plan and the applicable restricted stock award agreement and are subject to accelerated vesting upon a change in control, death or permanent disability.

(6) Pursuant to the terms of the restricted stock award agreement that we entered into with the Named Executive Officer on July 1, 2014, the shares of restricted stock vest over a three year period in equal portions beginning on the first anniversary of the grant date, such that 1/3 of the shares vest on the first anniversary of the grant date, 1/3 of the shares vest on the second anniversary of the grant date and 1/3 of the shares vest on the third anniversary of the grant date, provided that the holder of the restricted stock remains employed with us on that date. These shares of restricted stock are subject to forfeiture and other restrictions as more fully set forth in the Incentive Plan and the restricted stock award agreement and are subject to accelerated vesting upon a change in control, death or permanent disability.

(7) Share amounts represent the target level achievement for performance-based RSUs, which equals 50% of the target number of RSUs granted on July 1, 2014 and is the most probable level of payout other than no award. The actual number of shares that will vest is between 0% and 200% of the target number of RSUs on July 1, 2017 based on the Company's achievement of TSR relative to the TSR achieved by a peer group established by the compensation committee. These RSUs were issued to the Named Executive Officer pursuant to the Incentive Plan and an RSU award agreement dated as of July 1, 2014 and are subject to forfeiture, accelerated vesting and other restrictions as more fully set forth in the Incentive Plan and the RSU award agreement.

(8) Represents shares of restricted stock issued to Mr. Burnett on December 2, 2013 that vest over a three year period in equal portions beginning on the first anniversary of the grant date, such that 1/3 of the shares vest on the first anniversary of the grant date, 1/3 of the shares vest on the second anniversary of the grant date and 1/3 of the shares vest on the third anniversary of the grant date, provided that Mr. Burnett remains employed with us on that date.

(9) Represents shares of restricted stock issued to Mr. Burnett pursuant to a restricted stock award agreement dated September 2, 2014. The shares of restricted stock vest over a three year period in equal portions beginning on the first anniversary of the grant date, such that 1/3 of the shares vest on the first anniversary of the grant date, 1/3 of the shares vest on the second anniversary of the grant date and 1/3 of the shares vest on the third anniversary of the grant date, provided that Mr. Burnett remains employed with us on that date. These shares of restricted stock are subject to forfeiture and other restrictions as more fully set forth in the Incentive Plan and the restricted stock award agreement and are subject to accelerated vesting upon a change in control, death or permanent disability.

(10) Share amounts represent the target level achievement for performance-based RSUs, which equals 50% of the target number of RSUs granted on September 2, 2014 and is the most probable level of payout other than no award. The actual number of shares that will vest is between 0% and 200% of the target number of RSUs on July 1, 2017 based on the Company's achievement of TSR relative to the TSR achieved by a peer group established by the compensation committee. These RSUs were issued to Mr. Burnett pursuant to the Incentive Plan and an RSU award agreement dated as of September 2, 2014 and are subject to forfeiture, accelerated vesting and other restrictions as more fully set forth in the Incentive Plan and the RSU award agreement.

OPTION EXERCISES AND STOCK VESTED DURING 2014

None of our Named Executive Officers exercised any stock options during 2014. The following table summarizes the vesting of restricted stock awards for each of our Named Executive Officers (including Mr. Mulhern) during the fiscal year ended December 31, 2014.

	Option Awards		**Stock Awards**	
Name and Principal Position	**Number of Shares Acquired on Exercise (#)**	**Value Realized on Exercise ($)**	**Number of Shares Acquired on Vesting (#)**	**Value Realized on Vesting ($)**
Harold L. Hickey	—	—	5,166(1)	22,937(6)
Chief Executive Officer and	—	—	72,131(2)	272,655(7)
President and Former Chief	—	—	6,933(3)	15,530(8)
Operating Officer				
Richard A. Burnett				
Vice President, Chief Financial	—	—	28,333(4)	74,516(9)
Officer and Chief Accounting				
Officer				
Mark F. Mulhern				
Former Executive Vice	—	—	33,334(5)	185,670(10)
President and Chief				
Financial Officer				
William L. Boeing	—	—	5,733(1)	25,454(6)
Vice President, General	—	—	79,645(2)	301,058(7)
Counsel and Secretary	—	—	7,700(3)	17,248(8)

(1) Pursuant to the terms of the restricted stock award agreement that we entered into with the Named Executive Officer on August 15, 2011, the award vested in equal proportions over three years with one-third vested on August 15, 2012, one-third vested on August 15, 2013 and one-third vested on August 15, 2014.

(2) Pursuant to the terms of the restricted stock award agreement that we entered into with the Named Executive Officer on November 21, 2011, the award vests over a five year period with 60% of the shares vesting on the third anniversary of the grant date, 20% of the shares vesting on the fourth anniversary of the grant date and 20% of the shares vesting on the fifth anniversary of the grant date, provided that the holder of the restricted stock award remains employed with us on that date. These shares become fully vested and exercisable, subject to their early termination as provided in the restricted stock award agreements, immediately prior to a change of control of us.

(3) Pursuant to the terms of the restricted stock award agreement that we entered into with the Named Executive Officer on December 13, 2012, the award vests in equal proportions over three years with one-third vesting on December 13, 2013, one-third vesting on December 13, 2014 and one-third vesting on December 13, 2015, provided that the holder of the restricted stock award remains employed with us on that date.

(4) Pursuant to the terms of a restricted stock award agreement that we entered into with the Named Executive Officer on December 2, 2013, the award vests in equal proportions over three years with one-third vesting December 2, 2013, one-third vesting December 2, 2014 and one-third vesting December 2, 2015.

(5) Pursuant to the terms of a restricted stock award agreement that we entered into with Mr. Mulhern on April 1, 2013, the award vests in equal proportions over three years with one-third vesting April 1, 2014, one-third vesting April 1, 2015 and one-third vesting April 1, 2016, provided that the Mr. Mulhern remained employed with us on that date. The unvested portion of this award was forfeited upon Mr. Mulhern's resignation, which was effective September 19, 2014.

(6) Market value is based on $4.44 per share closing price of our common stock as reported on the NYSE as of August 15, 2014.

(7) Market value is based on $3.78 per share closing price of our common stock as reported on the NYSE as of November 21, 2014.

(8) Market value is based on $2.24 per share closing price of our common stock as reported on the NYSE as of December 12, 2014.

(9) Market value is based on $2.63 per share closing price of our common stock as reported on the NYSE as of December 2, 2014.

(10) Market value is based on $5.57 per share closing price of our common stock as reported on the NYSE as of April 1, 2014.

Pension Benefits

We do not provide any pension benefits for our Named Executive Officers.

Nonqualified Defined Contribution and Other Nonqualified Deferred Compensation Plans

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

Potential Payments Upon Termination or Change of Control

Fourth Amended and Restated EXCO Resources, Inc. Severance Plan

We have adopted the Fourth Amended and Restated EXCO Resources, Inc. Severance Plan (the "Severance Plan"), which provides that, among other things, (i) employees are eligible for severance pay equal to 1.25 times their base pay, (ii) there is a 12-month protection period following a change of control for eligible employees, and (iii) eligible employees can terminate for "good reason" due to a material reduction in base pay or a forced relocation. The Severance Plan provides for the payment of severance in the event the employee's employment was terminated or there was an adverse change in the employee's job or compensation, as more specifically described in the Severance Plan, within twelve months following a change of control of EXCO. The Severance Plan is administered by our compensation committee, which has the sole discretion to determine whether an employee's termination of employment is eligible for payment of severance. All of our regular, full-time employees are eligible to participate in and receive benefits under the Severance Plan.

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

Severance payment will be made only if the employee fully executes a release form with the plan administrator, to release and forever discharge us from any and all liability which the employee may have against us as a result of employment with or subsequent termination from us. Severance payment is equal to 1.25 times an employee's base salary to be paid in cash in a lump sum 60 days following termination of employment, provided that we have timely received an executed release form.

Severance Arrangements with our Former Chief Executive Officer

In connection with his resignation as chairman and chief executive officer effective November 20, 2013, we entered into a Settlement Agreement and Mutual Release and Waiver of Claims (the "Settlement Agreement") with Douglas H. Miller. Pursuant to the Settlement Agreement, we paid Mr. Miller $4.0 million on November 29, 2013 and $1.0 million on December 31, 2014. In addition, we agreed to provide health care benefits coverage for Mr. Miller and his dependents through May 31, 2015.

Potential Payments

The following table shows potential payments to our Named Executive Officers (including Mr. Mulhern) for various scenarios involving a change of control, death or disability, using, where applicable, the closing price of our common stock of $2.17 as reported on the NYSE as of December 31, 2014 and assuming that the applicable triggering event occurred on December 31, 2014.

Executive Benefits and Payments Upon Termination	Termination for Cause or Misconduct Within 12 Months After a Change of Control	Termination Not for Cause or Misconduct or by the Executive for Good Reason Within 12 Months After a Change of Control	Change of Control (No Termination)	Death	Disability
Harold L. Hickey(1)					
Severance	$ —	$ 937,500(2)	$ —	$ —	$ —
Long-term Equity Incentives					
—Unvested Stock Options(3)	—	—	—	—	—
—Unvested Restricted Stock Awards(4)	557,228	557,228	557,228	557,228	557,228
—Unvested RSUs(5)	226,042	226,042	226,042	226,042	226,042
Total	$ 783,270	$ 1,720,770	$ 783,270	$ 783,270	$ 783,270
Richard A. Burnett(6)					
Severance	$ —	$ 593,750(2)	$ —	$ —	$ —
Long-term Equity Incentives					
—Unvested Stock Options(3)	—	—	—	—	—
—Unvested Restricted Stock Awards(4)	509,501	509,501	509,501	509,501	509,501
—Unvested RSUs(5)	169,533	169,533	169,533	169,533	169,533
Total	$ 679,034	$ 1,272,784	$ 679,034	$ 679,034	$ 679,034
Mark F. Mulhern(7)					
Severance	$ —	$ —	$ —	$ —	$ —
Long-term Equity Incentives					
—Unvested Stock Options(3)	—	—	—	—	—
—Unvested Restricted Stock Awards(4)	—	—	—	—	—
—Unvested RSUs(5)	—	—	—	—	—
Total	$ —	$ —	$ —	$ —	$ —
William L. Boeing(1)					
Severance	$ —	$ 625,000(2)	$ —	$ —	$ —
Long-term Equity Incentives					
—Unvested Stock Options(3)	—	—	—	—	—
—Unvested Restricted Stock Awards(4)	463,866	463,866	463,866	463,866	463,866
—Unvested RSUs(5)	226,042	226,042	226,042	226,042	226,042
Total	$ 689,908	$ 1,314,908	$ 689,908	$ 689,908	$ 689,908

(1) As of December 31, 2014, we had not hired a new chief executive officer of the Company and no Special Severance Benefits were payable pursuant to the Retention Agreements.
(2) Represents a payment equal to 1.25 times officer's annual base salary pursuant to our Severance Plan. The applicable Named Executive Officer shall not be eligible to receive a severance payment if either (a) he receives a comparable offer of employment from any other operation of EXCO or any of its affiliate organizations, regardless of whether he accepts such offer or (b) he receives and accepts a transfer of employment to any other operation of EXCO or any of its affiliate organizations.
(3) Excludes stock options that are currently exercisable. The exercise price of all unvested stock option awards exceeded the $2.17 closing price of our common stock as reported on the NYSE on December 31, 2014. Pursuant to the terms of each stock option award, all options become fully vested automatically upon a change of control or upon the death or the total and permanent disability of the officer.
(4) Pursuant to the terms of each restricted stock award agreement, all shares of restricted stock become fully vested automatically upon a change of control or upon the death or the total and permanent disability of the officer.
(5) Pursuant to the terms of each RSU award agreement, upon a change of control or upon the death or the total and permanent disability of the officer, unvested RSUs become fully vested based on the achievement of the performance criteria as of the date of such triggering event. For purposes of this table, we assumed that 100% of target RSUs will vest as further described under "—Compensation Discussion and Analysis—Executive Compensation Components—Long-Term Incentive Compensation—Restricted Stock Units."
(6) Pursuant to the Burnett Retention Agreement, if Mr. Burnett's employment is terminated without cause or by Mr. Burnett for good reason during the period beginning on September 1, 2014 and ending on the later of March 1, 2015 or the date on which we hire a new chief executive officer, Mr. Burnett is also entitled to (a) a cash payment equal to his annual base salary, or $475,000, and (b) COBRA benefits for up to 12 months following such termination.
(7) Mr. Mulhern resigned effective as of September 19, 2014 and was not entitled to any payments in connection with such resignation.

Director Compensation

The following table provides compensation information for the year ended December 31, 2014 for each non-employee member of our board of directors:

2014 FISCAL YEAR DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Jeffrey D. Benjamin (3)	400,000	14,150	—	—	—	—	414,150
Earl E. Ellis (4)	15,714	—	—	—	—	—	15,714
B. James Ford	55,000	14,150	—	—	—	—	69,150
Samuel A. Mitchell	55,000	14,150	—	—	—	—	69,150
T. Boone Pickens (5)	40,000	14,150	—	—	—	—	54,150
Wilbur L. Ross, Jr.	50,000	14,150	—	—	—	—	64,150
Jeffrey S. Serota	55,000	14,150	—	—	—	—	69,150
Robert L. Stillwell	60,000	14,150	—	—	—	—	74,150

(1) Includes the amount of cash fees forgone at the election of Messrs. Benjamin and Ellis and either paid during 2014 or deferred until a later date in shares of our common stock pursuant to the Director Plan (as defined below). See "—Director Plan."

(2) This column provides the aggregate grant date fair value of shares of restricted stock issued to each non-employee director in 2014 in accordance with ASC 718, with the exception that the amount shown assumes no forfeitures. Assumptions used in the calculation of these amounts are included in "Note 2. Summary of significant accounting policies—Share-based compensation" and "Note 11. Stock options and awards" to our audited financial statements for the fiscal year ended December 31, 2014 included in this Annual Report on Form 10-K. Pursuant to the policies of Oaktree, Mr. Ford must hold these shares of restricted stock on behalf of and for the sole benefit of Oaktree and has assigned all economic, pecuniary and voting rights to Oaktree.
(3) Mr. Benjamin serves as non-executive chairman of the board of directors and received a fee in the amount of $25,000 per month during 2014 for such service.
(4) Represents fees earned for service on our board of directors from January 1, 2014 to May 22, 2014. Mr. Ellis did not stand for re-election at the 2014 Annual Meeting.
(5) Mr. Pickens resigned from our board of directors effective March 2, 2015.

Cash Compensation. Our non-employee directors were paid an annual retainer of $40,000 in 2014. Our non-executive chairman was paid an additional fee of $25,000 per month for his service. The chairs of our compensation committee and nominating and corporate governance committee were each paid an additional $10,000 in 2014 and the chair of the audit committee was paid an additional $50,000 in 2014. Each non-chair member of our compensation committee, nominating and corporate governance committee and audit committee was paid an additional $5,000 in 2014. We pay no additional remuneration to our employees serving as directors. All directors, including our employee directors (if any), are reimbursed for reasonable out-of-pocket expenses incurred in connection with their attendance at meetings of the board of directors and committee meetings. The board of directors has not made any changes to director compensation for fiscal 2015.

Restricted Stock Grant. On October 30, 2014, each of our non-employee directors received an automatic annual grant of 5,000 shares of restricted stock pursuant to the Amended and Restated 2007 Director Plan (the "Director Plan") and the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan (the "Incentive Plan"). Pursuant to the Director Plan, the automatic annual grants of shares of restricted stock are made on the second trading day after the press release containing the Company's third quarter earnings is issued. Such shares of restricted stock will vest on the first anniversary of the date of grant or automatically upon a change in control as defined in the Incentive Plan. However, no shares granted under the Director Plan will vest, and the shares that would otherwise have vested will be forfeited, in any fiscal year in which a director attends less than 75% of the board of directors meetings held for that fiscal year. In the event a director ceases to serve as a director for any reason, such director's unvested shares of restricted stock will be forfeited.

Director Plan. The Director Plan permits non-employee directors who receive fees for their service on the board of directors and its committees to make an annual election to receive their fees (i) entirely in cash, (ii) 50% in cash and 50% in our common stock, or (iii) entirely in our common stock. Messrs. Ford, Mitchell, Pickens, Ross, Serota and Stillwell elected to receive cash for their service during 2014. For his service during 2014, Mr. Benjamin elected to receive his fees 50% in cash and 50% in our common stock. Mr. Ellis elected to receive his fees for service from January 1, 2014 through May 22, 2014 entirely in our common stock. All director fees are paid on a quarterly basis. Payments in the form of our common stock are issued as of the payment date, which is the first business day following the end of the fiscal quarter, at the closing price of our common stock on the NYSE on that date.

The Director Plan also permits a non-employee director to defer the payment of his or her director fees (employee directors do not receive fees in their capacity as directors). A director may defer the payment of director fees, whether payable in the form of cash or our common stock, to (i) a specified date, (ii) his or her termination of service, (iii) the occurrence of a change of control, or (iv) the earlier of two or more of those events. This deferral satisfies the requirements of Section 409A of the Code. Mr. Benjamin elected to defer the payment of his 2014 director fees that are paid in our common stock under the Director Plan.

Compensation Committee Interlocks and Insider Participation

During the fiscal year ended December 31, 2014, the compensation committee was comprised of Messrs. Stillwell (chair), Benjamin, Ford, Mitchell, Ross and Serota.

During the fiscal year ended December 31, 2014, no member of our compensation committee was or had been an officer or employee of us or any of our subsidiaries or had any relationship requiring disclosure pursuant to Item 404 of Regulation S-K. None of our executive officers served as a director or member of the compensation committee (or other board committee performing similar functions or, in the absence of any such committee, the entire board of directors) of another entity, one of whose executive officers served on our compensation committee or as one of our directors.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Equity Compensation Plan Information

The following table provides certain information as of December 31, 2014 with respect to our equity compensation plans under which our equity securities are authorized for issuance:

	(a)	(b)	(c)
Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	10,150,518	$ 12.58	18,517,815
Equity compensation plans not approved by security holders	Not applicable	Not applicable	Not applicable
Total	10,150,518	$ 12.58	18,517,815

Security Ownership of Certain Beneficial Owners and Management

The following tables set forth as of March 31, 2015 (unless otherwise specified) the number and percentage of shares of our common stock beneficially owned by (i) each person known by us to beneficially own more than 5% of the outstanding shares of our common stock, (ii) each of our directors, each of our director nominees and each of our Named Executive Officers (including Mr. Mulhern) and (iii) all of our directors, director nominees and executive officers as a group.

Beneficial ownership is determined in accordance with the rules of the SEC. Beneficial ownership information is based on the most recent Forms 3, 4 and 5 and Schedules 13D and 13G filings with the SEC and reports made directly to us. In computing the number of shares of common stock beneficially owned by a person and the beneficial ownership percentage of that person, shares of common stock subject to options held by that person that are currently exercisable or exercisable within 60 days of March 31, 2015 are deemed outstanding, but are not deemed outstanding for computing the percentage ownership of any other person. Percentage of beneficial ownership of our common stock is based upon 273,702,116 shares of common stock outstanding as of March 31, 2015. To our knowledge, except as set forth in the footnotes to this table and subject to applicable community property laws, each person named in the table has sole voting and investment power with respect to the shares set forth opposite such person's name. Unless otherwise indicated in a footnote, the address for each individual listed below is c/o EXCO Resources, Inc., 12377 Merit Drive, Suite 1700, Dallas, Texas 75251.

Principal Shareholders

	Common Stock Beneficial Ownership	
Beneficial owner	Shares	% of Class
Holders of more than 5%		
WL Ross & Co. LLC(1) 1166 Avenue of the Americas New York, New York 10036	51,104,050	18.67%
Oaktree Capital Group Holdings GP, LLC(2) 333 S. Grand Avenue, 28th Floor Los Angeles, CA 90071	45,254,932	16.53%
Fairfax Financial Holdings Limited(3) 95 Wellington Street West Suite 800 Toronto, Ontario A6 M5K 1B1	17,538,912	6.41%

(1) Based solely on the information contained in the Schedule 13D/A filed with the SEC on January 17, 2014.

(2) Based solely on the information contained in the Schedule 13D/A filed with the SEC on January 15, 2014 and includes options to purchase an aggregate of 81,250 shares of our common stock held by Mr. Ford for the benefit of Oaktree as described below in note 7 to the beneficial ownership table for "Executive Officers, Directors and Director Nominees".
(3) Based solely on the information contained in the Schedule 13G/A filed with the SEC on February 13, 2015.

Executive Officers, Directors and Director Nominees

Beneficial owner	Shares(1)	Options exercisable within 60 days	Percentage of shares outstanding
Named Executive Officers			
Harold L. Hickey	1,089,015(2)	447,950	*
Richard A. Burnett	331,126(3)	62,500	*
William L. Boeing	1,088,324(4)	746,150	*
Mark F. Mulhern	70,659(5)	—	*
Directors and Director Nominees			
Jeffrey D. Benjamin	464,553(6)	81,250	*
B. James Ford	86,250(7)	81,250	*
Samuel A. Mitchell	72,500(8)	2,500	*
Wilbur L. Ross, Jr.	11,250(9)	6,250	*
Jeffrey S. Serota	86,250(10)	81,250	*
Robert L. Stillwell	178,354(11)	81,250	*
All executive officers and directors as a group (10 persons)	3,478,281	1,590,350	1.27%

(1) Includes the options exercisable within 60 days of March 31, 2015 shown in the options column.
(2) Includes (a) 20,815 shares of our common stock held in a 401(k) account, (b) 120,218 shares of restricted stock issued on November 21, 2011 that vest over five years with 60% vesting on November 21, 2014, 20% vesting on November 21, 2015 and 20% vesting on November 21, 2016, (c) 20,800 shares of restricted stock issued on December 13, 2012 that vest in equal proportions over three years with one-third vesting on December 13, 2013, one-third vesting on December 13, 2014 and one-third vesting on December 13, 2015, (d) 97,600 shares of restricted stock issued on August 13, 2013 with performance-based vesting conditions described under "—Compensation Discussion and Analysis—Executive Compensation Components—Long-Term Incentive Compensation—Restricted Stock Grants", (e) 104,167 shares of restricted stock issued on July 1, 2014 that vest in equal proportions over three years with one-third vesting on July 1, 2015, one-third vesting on July 1, 2016 and one-third vesting on July 1, 2017, and (f) the vested portion of (i) an option to purchase 166,700 shares of our common stock granted on October 5, 2005, all of which have vested, (ii) an option to purchase 30,000 shares of our common stock granted on December 1, 2006, all of which have vested, (iii) an option to purchase 35,000 shares of our common stock granted on December 4, 2007, all of which have vested, (iv) an option to purchase 35,000 shares of our common stock granted on December 11, 2008, all of which have vested, (v) an option to purchase 35,000 shares of our common stock granted on December 1, 2009, all of which have vested, (vi) an option to purchase 43,800 shares of our common stock granted on December 7, 2010, all of which have vested, and (vii) an option to purchase 204,900 shares of our common stock granted on August 13, 2013, of which 102,450 have vested. Excludes 104,167 performance-based RSUs issued on July 1, 2014.
(3) Includes (a) 85,000 shares of restricted stock issued on December 2, 2013 that vest in equal proportions over three years with one-third vesting on December 2, 2013, one-third vesting on December 2, 2014 and one-third vesting on December 2, 2015, (b) 39,063 shares of restricted stock issued on July 1, 2014 that vest in equal proportions over three years with one-third vesting on July 1, 2015, one-third vesting on July 1, 2016 and one-third vesting on July 1, 2017, (c) 139,063 shares of restricted stock issued on September 2, 2014 that vest in equal proportions over three years with one-third vesting on September 2, 2015, one-third vesting on September 2, 2016 and one-third vesting on September 2, 2017 and (d) the vested portion of an option to purchase 125,000 shares of our common stock granted on December 2, 2013, of which 62,500 have vested. Excludes 39,063 performance-based RSUs issued on July 1, 2014 and 39,063 performance-based RSUs issued on September 2, 2014.

(4) Includes (a) 132,741 shares of restricted stock issued on November 21, 2011 that vest over five years with 60% vesting on November 21, 2014, 20% vesting on November 21, 2015 and 20% vesting on November 21, 2016, (b) 23,100 shares of restricted stock issued on December 13, 2012 that vest in equal proportions over three years with one-third vesting on December 13, 2013, one-third vesting on December 13, 2014 and one-third vesting on December 13, 2015, (c) 48,800 shares of restricted stock issued on August 13, 2013 with performance-based vesting conditions described under "—Compensation Discussion and Analysis—Executive Compensation Components—Long-Term Incentive Compensation—Restricted Stock Grants", (d) 104,167 shares of restricted stock issued on July 1, 2014 that vest in equal proportions over three years with one-third vesting on July 1, 2015, one-third vesting on July 1, 2016 and one-third vesting on July 1, 2017, and (e) the vested portion of (i) an option to purchase 500,000 shares of our common stock on April 5, 2006, all of which have vested, (ii) an option to purchase 26,200 shares of our common stock on December 1, 2006, all of which have vested, (iii) an option to purchase 40,000 shares of our common stock on December 4, 2007, all of which have vested, (iv) an option to purchase 40,000 shares of our common stock granted on December 11, 2008, all of which have vested, (v) an option to purchase 40,000 shares of our common stock granted on December 1, 2009, all of which have vested, (vi) an option to purchase 48,700 shares of our common stock granted on December 7, 2010, all of which have vested, and (vii) an option to purchase 102,500 shares of our common stock granted on August 13, 2013, of which 51,250 have vested. Excludes 104,167 performance-based RSUs issued on July 1, 2014.

(5) In connection with Mr. Mulhern's resignation in September 2014, he forfeited (a) all unvested shares of restricted stock, (b) all options to purchase shares of our common stock granted for his service on our board of directors and (c) all options to purchase shares of our common stock granted as executive compensation. Accordingly, this figure is based on Mr. Mulhern's ownership on the date of his resignation and includes 33,334 shares of restricted stock that vested on April 1, 2014. Also includes 9,220 shares of our common stock issued to Mr. Mulhern under the Director Plan in lieu of cash compensation for his service on our board of directors and committees.

(6) Includes the right to acquire 116,300 shares of our common stock granted pursuant to the Director Plan as deferred compensation in lieu of cash for service on our board of directors and committees. These shares will vest immediately and are to be settled in our common stock upon the earlier to occur of (a) as soon as administratively feasible after the date on which Mr. Benjamin incurs a "Termination of Service" under the Director Plan and (b) a "Change in Control" under the Director Plan. See "—Director Compensation" for a discussion of the Director Plan. Also includes (x) 5,000 shares of restricted stock granted on October 30, 2014 that vest in full on October 30, 2015, subject to certain conditions set forth in the Director Plan, and (y) the vested portion of (i) an option to purchase 50,000 shares of our common stock granted on October 5, 2005, all of which have vested, (ii) an option to purchase 15,000 shares of our common stock granted on December 1, 2009, all of which have vested, (iii) an option to purchase 5,000 shares of our common stock granted on November 5, 2010, all of which have vested, (iv) an option to purchase 5,000 shares of our common stock granted on November 4, 2011, all of which have vested, (v) an option to purchase 5,000 shares of our common stock granted on November 1, 2012, of which 3,750 have vested and (vi) an option to purchase 5,000 shares of our common stock granted on November 1, 2013, of which 2,500 have vested. The shares of restricted stock and options described in the preceding sentence were granted in connection with Mr. Benjamin's appointment to and service on our board of directors.

(7) Consists of (a) 5,000 shares of restricted stock granted on October 30, 2014 that vest in full on October 30, 2015, subject to certain conditions set forth in the Director Plan, and (b) the vested portion of (i) an option to purchase 50,000 shares of our common stock granted to Mr. Ford, a Managing Director of Oaktree, upon becoming one of our directors in December 2007, all of which have vested, (ii) an option to purchase 15,000 shares of our common stock granted on December 1, 2009, all of which have vested, (iii) an option to purchase 5,000 shares of our common stock granted on November 5, 2010, all of which have vested (iv) an option to purchase 5,000 shares of our common stock granted on November 4, 2011, all of which have vested, (v) an option to purchase 5,000 shares of our common stock granted on November 1, 2012, of which 3,750 have vested and (vi) an option to purchase 5,000 shares of our common stock issued to Mr. Ford on November 1, 2013, of which 2,500 have vested. The shares of restricted stock and options described in the preceding sentence were granted in connection with Mr. Ford's appointment to and service on our board of directors, and are held directly by Mr. Ford for the benefit of Oaktree. Pursuant to the policies of Oaktree, Mr. Ford must hold these stock options and shares of restricted stock on behalf of and for the sole benefit of Oaktree and has assigned all economic, pecuniary and voting rights to Oaktree. Mr. Ford disclaims beneficial ownership of these securities, except to the extent of any indirect pecuniary interest therein. Amounts reported for Mr. Ford do not include the shares of our common stock referred to in note 2 to the beneficial ownership table for "Holders of more than 5%" above, with respect to which Mr. Ford disclaims beneficial ownership, except to the extent of any indirect pecuniary interest therein.

(8) Consists of (a) 5,000 shares of restricted stock granted on October 30, 2014 that vest in full on October 30, 2015, subject to certain conditions set forth in the Director Plan, and (b) the vested portion of an option to purchase 5,000 shares our common stock granted on November 1, 2013, of which 2,500 have vested. The shares of restricted stock and options described in the preceding sentence were granted in connection with Mr. Mitchell's service on our board of directors. Mr. Mitchell serves as a managing director and a member of the investment committee of Hamblin Watsa, which manages the investment portfolios of Fairfax Financial. Amounts reported do not include the shares of our common stock held by Fairfax Financial. Mr. Mitchell expressly disclaims beneficial ownership of our shares of common stock that are held by Fairfax Financial.

(9) Consists of (a) 5,000 shares of restricted stock granted on October 30, 2014 that vest in full on October 30, 2015, subject to certain conditions set forth in the Director Plan, and (b) the vested portion of (i) an option to purchase 5,000 shares of our common stock granted on November 1, 2012, of which 3,750 have vested and (ii) an option to purchase 5,000 shares of our common stock granted on November 1, 2013, of which 2,500 have vested. The shares of restricted stock and options described in the preceding sentence were granted in connection with Mr. Ross' service on our board of directors. Amounts reported for Mr. Ross do not include the shares of our common stock referred to in note 1 to the beneficial ownership table for "Holders of more than 5%" above, with respect to which Mr. Ross disclaims beneficial ownership, except to the extent of any indirect pecuniary interest therein.

(10) Includes (a) 5,000 shares of restricted stock granted on October 30, 2014 that vest in full on October 30, 2015, subject to certain conditions set forth in the Director Plan, and (b) the vested portion of (i) an option to purchase 50,000 shares of our common stock granted on March 30, 2007, all of which have vested, (ii) an option to purchase 15,000 shares of our common stock granted on December 1, 2009, all of which have vested, (iii) an option to purchase 5,000 shares of our common stock granted on November 5, 2010, all of which have vested, (iv) an option to purchase 5,000 shares of our common stock granted on November 4, 2011, all of which have vested, (v) an option to purchase 5,000 shares of our common stock granted on November 1, 2012, of which 3,750 have vested and (vi) an option to purchase 5,000 shares of our common stock granted on November 1, 2013, of which 2,500 have vested. The shares of restricted stock and options described in the preceding sentence were granted in connection with Mr. Serota's appointment to and service on our board of directors. Pursuant to an arrangement between Ares and Mr. Serota, Mr. Serota has assigned all economic, pecuniary and voting rights with respect to the stock options that vested on or before December 31, 2013 to Ares while the unvested portion of such stock options as well as shares of restricted stock granted after December 31, 2013, were not assigned to Ares and are owned solely by Mr. Serota. Mr. Serota expressly disclaims beneficial ownership of the stock options he holds for the benefit of Ares.

(11) Includes the right to acquire 5,404 shares of our common stock granted pursuant to the Director Plan as deferred compensation in lieu of cash for Mr. Stillwell's service on our board of directors and committees. These shares vested immediately and are to be settled in our common stock upon the earlier to occur of (a) as soon as administratively feasible after the date on which Mr. Stillwell incurs a "Termination of Service" under the Director Plan and (b) a "Change in Control" under the Director Plan. See "—Director Compensation" for a discussion of the Director Plan. Also includes (x) 10,000 shares held by Mr. Stillwell's spouse, (y) 5,000 shares of restricted stock granted on October 30, 2014 that vest in full on October 30, 2015, subject to certain conditions set forth in the Director Plan, and (z) the vested portion of (i) an option to purchase 50,000 shares of our common stock granted on October 5, 2005, all of which have vested, (ii) an option to purchase 15,000 shares of our common stock granted on December 1, 2009, all of which have vested, (iii) an option to purchase 5,000 shares of our common stock granted on November 5, 2010, all of which have vested, (iv) an option to purchase 5,000 shares of our common stock granted on November 4, 2011, all of which have vested, (v) an option to purchase 5,000 shares of our common stock granted on November 1, 2012, of which 3,750 have vested and (vi) an option to purchase 5,000 shares of our common stock granted on November 1, 2013, of which 2,500 have vested. The shares of restricted stock and options described in clauses (y) and (z) were granted in connection with Stillwell's appointment to and service on our board of directors.

* Less than 1%.

Item 13. Certain Relationships and Related Transactions and Director Independence

Transactions with Related Persons

Relationship with Kyle Hickey

Kyle Hickey, the son of Harold L. Hickey, our chief executive officer and president, is one of our employees. From January 1, 2014 through March 31, 2015, compensation paid to Mr. Kyle Hickey (including the value of equity awards) totaled approximately $186,000.

Investment Agreements

We entered into two investment agreements (individually, the "Investment Agreement," or, collectively, the "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 (together with WL Ross, the "Investors") 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 shares of common stock that rights holders do not elect to purchase in the Rights Offering pursuant to the basic subscription right (the "Unsubscribed Shares") under the over-subscription privilege, subject to availability and the pro rata allocation among rights holders who elected to exercise their over-subscription privilege; provided, that each of the Investors was not obligated to purchase an aggregate number of shares that would exceed the lesser of (i) 100% of the Unsubscribed Shares, or (ii) an amount of Unsubscribed Shares, which when taken together with the number of shares issued pursuant to the Investor's basic subscription right, equaled 50% of the total shares offered in the rights offering. For additional information concerning the Investment Agreements, please see the description in our Current Report on Form 8-K filed with the SEC on December 17, 2013, which description is incorporated by reference herein.

Rights Offering

On January 17, 2014, we issued 54,574,734 shares of our common stock pursuant to the Rights Offering and the transactions contemplated by the Investment Agreements for an aggregate subscription price of approximately $273 million. We issued 19,599,973 and 6,726,712 shares of common stock to 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. (collectively, the "WL Ross Purchasers") 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 (collectively, the "Hamblin Watsa Purchasers" and, together with the WL Ross Purchasers, the "Purchasers"), respectively, pursuant to the transactions contemplated by the Investment Agreements for aggregate subscription amounts of approximately $98.0 million and $33.6 million, respectively.

On January 17, 2014, in accordance with the terms of the Investment Agreements, we executed a Joinder Agreement to Registration Rights Agreement (the "WL Ross Joinder Agreement") with the WL Ross Purchasers and a Joinder Agreement to Registration Rights Agreement with the Hamblin Watsa Purchasers, each dated as of January 17, 2014. The Joinder Agreements relate to the Company's First Amended and Restated Registration Rights Agreement, dated December 30, 2005, by and among EXCO Holdings Inc. (our predecessor by merger) and the Initial Holders (as defined therein) (the "Registration Rights Agreement"). Pursuant to the Joinder Agreements, the Purchasers became "Holders" under the Registration Rights Agreement and shares owned by the Purchasers, including shares of common stock acquired under the Investment Agreements, became subject to the Registration Rights Agreement. The Registration Rights Agreement provides for, among other things, certain registration rights for shares of common stock that the Purchasers acquired pursuant to the Investment Agreements.

Audit Committee Review

In accordance with our audit committee charter, our audit committee is responsible for reviewing and approving the terms and conditions of all related party transactions that are required to be disclosed under Item 404 of Regulation S-K. Our Audit Committee Charter requires all transactions with related persons to be pre-approved by the audit committee. Our audit committee or the disinterested members of our board of directors pre-approved the foregoing related party transactions that occurred during 2014.

Director Independence

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

The board of directors, in applying the above-referenced standards, has affirmatively determined that our current "independent" directors are Jeffrey D. Benjamin, B. James Ford, Samuel A. Mitchell, Wilbur L. Ross, Jr., Jeffrey S. Serota and Robert L. Stillwell. As part of the board of directors' process in making such determination, each such director provided written assurances that (a) all of the above-cited objective criteria for independence are satisfied and (b) he has no other "material relationship" with us that could interfere with his ability to exercise independent judgment.

In determining that the directors above are "independent," the board of directors considered the transactions, relationships and arrangements described in our prior proxy statements and under this "Item 13. Certain Relationships and Related Transactions and Director Independence."

Item 14. Principal Accountant Fees and Services

Fees

Aggregate fees for professional services provided to us by our principal accountant, KPMG LLP, for the years ended December 31, 2014 and 2013 were as follows:

	2014	2013
	(in thousands)	
Audit Fees(a)	$ 1,722	$ 2,065
Audit-Related Fees(b)	111	22
Tax Fees(c)	237	108
All Other Fees(d)	—	200
Total	$ 2,070	$ 2,395

(a) Fees for audit services include fees associated with the annual audit, the reviews of EXCO's quarterly reports on Form 10-Q and Sarbanes-Oxley compliance test work.
(b) Audit-related fees principally include costs incurred related to accounting consultations related to generally accepted accounting principles and the application of generally accepted accounting principles to proposed transactions.
(c) Tax fees include tax compliance and tax planning.
(d) All other fees principally include costs incurred related to audits under Section 3-05 of Regulation S-X associated with the acquisition of oil and natural gas properties in the Haynesville and Eagle Ford shales in July 2013 and the formation of Compass in 2013.

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

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

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

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

- such non-audit services are promptly brought to the attention of the audit committee and approved by the audit committee prior to the completion of the audit.

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

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

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.

Date: April 10, 2015

EXCO RESOURCES, INC.
(Registrant)

/s/ Harold L. Hickey

Harold L. Hickey
President and Chief Executive Officer

INDEX TO EXHIBITS

Exhibit Number	Description of Exhibits
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.

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, 2014

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 Shares, $0.001 par value	**New York Stock Exchange**

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

None
(Title of class)

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ☐ NO ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES ☒ NO ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant is required to submit and post such files). YES ☒ NO ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form10-K or any amendment to this Form 10-K. ☒

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

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

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

As of February 19, 2015, the registrant had 273,763,414 outstanding common shares, par value $0.001 per share, which is its only class of common shares. 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 shares held by non-affiliates was approximately $897,416,000.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement on Schedule 14A to be furnished to shareholders in connection with its 2015 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.

TABLE OF CONTENTS

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 26.

We are an independent oil and natural gas company engaged in the exploration, exploitation, 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, 2014, our Proved Reserves were approximately 1.3 Tcfe, of which 91% were natural gas and 47% were Proved Developed Reserves. As of December 31, 2014, the PV-10 and Standardized Measure of our Proved Reserves were approximately $1.5 billion. This represents an increase in Proved Reserves of 12% and PV-10 and Standardized Measure of 23% compared to the prior year. For the year ended December 31, 2014, we produced 135.7 Bcfe of oil, natural gas and natural gas liquids ("NGLs").

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 maintaining 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. This includes a diverse portfolio of both oil and natural gas assets that provide us the optionality to allocate capital to enhance our returns under various commodity price environments. We hold significant acreage positions in three prominent shale plays in the United States:

- East Texas and North Louisiana - we currently hold approximately 85,300 net acres in the Haynesville and Bossier shales;
- South Texas - we currently hold approximately 52,900 net acres in the Eagle Ford shale; and
- Appalachia - we currently hold approximately 157,000 net acres prospective in the Marcellus shale.

We have extensive amounts of technical and operational expertise within the Haynesville and Bossier shales. We have accumulated significant amounts of contiguous acreage and are one of the largest operators within this region. Our economies of scale and operational expertise have allowed us to efficiently develop our assets and minimize our costs through greater utilization of multi-well pads and existing infrastructure and facilities.

We have applied our technical and operational expertise from other shale plays to the Eagle Ford shale since we acquired the assets on July 31, 2013. We have realized significant improvements in our drilling performance and the optimization of our well design has yielded strong results. We have a participation agreement with a joint venture partner ("Participation Agreement") to develop certain assets in the Eagle Ford shale which allows 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 Participation Agreement. Our position also includes producing properties and undeveloped locations in the Eagle Ford shale, Buda formation and other formations which are not included as part of the Participation Agreement.

Our principal activities in the Marcellus shale are focused on technical evaluations of our acreage holdings and a disciplined appraisal drilling program. We will continue our appraisal program as we evaluate future development activities in 2015. A substantial portion of our shale resource play acreage is held-by-production, which gives us flexibility to control the timing of our development activities in the region.

Evaluate complementary acquisitions that meet our strategic and financial objectives

We continue to evaluate acreage opportunities and acquisitions of producing properties in our core areas. We believe we can leverage our technical expertise and economies of scale to maximize our returns in these areas. Our recent acquisition history has been focused on shale resource plays with an emphasis on the acquisition of 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 2014, we executed several key transactions that improved our liquidity and financial flexibility. We utilized the proceeds from these transactions to reduce indebtedness under our credit agreement ("EXCO Resources Credit Agreement"). These transactions included the following:

- closed a rights offering and related private placement of our common shares ("Rights Offering") on January 17, 2014, which resulted in the issuance of 54,574,734 shares of our common shares for gross proceeds of $272.9 million;
- sold our interest in certain non-operated assets in the Permian Basin, including producing wells and undeveloped acreage, for approximately $68.2 million;
- completed a public offering of $500.0 million in aggregate principal amount of senior unsecured notes due April 15, 2022 ("2022 Notes"). We received net proceeds of approximately $490.0 million after offering fees and expenses; and
- sold our entire interest in Compass Production Partners, L.P. ("Compass") for $118.8 million in cash.

Our board of directors approved a capital expenditure budget of up to $275.0 million for 2015. Our budget was designed to allocate capital based on projects with the highest rate of return and other strategic initiatives which will unlock additional value in our assets. We believe the capital budget is appropriate for the current commodity price environment and is expected to result in a reduction in capital expenditures of approximately 35% compared to the prior year. We expect the capital expenditure program will be funded primarily by our operating cash flows as well as borrowings under the EXCO Resources Credit Agreement. Our capital expenditure budget will allow us to preserve our liquidity and capital resources in preparation for future growth. We amended the EXCO Resources Credit Agreement on February 6, 2015, which modified our financial covenants which provides us with the financial flexibility to selectively develop our asset base while deferring a significant amount of our drilling inventory until commodity prices improve. In connection with the amendment, our borrowing base was reduced to $725.0 million as a result of the recent declines in commodity prices compared to prices in effect at the prior borrowing base redetermination. This would have resulted in pro forma liquidity of $586.2 million as of December 31, 2014.

We are evaluating potential transactions which would further enhance our liquidity including additional divestitures of non-core assets and cost reduction initiatives. As a result of the current commodity price environment, we have negotiated reductions in service costs with several key vendors and will continue to pursue further reductions. Also, we have implemented initiatives to reduce our general and administrative costs, including a 15% reduction in our workforce during 2015. The cost reduction initiatives will allow us to maximize our cash flows in a low commodity price environment.

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 help mitigate the impact of volatility in commodity prices and allow us to achieve more predictable cash flows.

Our strengths

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, 2014, we operated 6,559 of our 7,066 gross wells, or wells representing approximately 93% 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 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 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 2015

Our plans for 2015 primarily focus on the exploitation and development of our core areas and cost containment throughout our organization. In response to the low commodity price environment, we plan to reduce our drilling program compared to the prior year. We believe the capital projects included in our plans for 2015 still provide attractive returns in a low commodity price environment. We will continue to focus on operational initiatives to enhance our well designs, optimize our base production and maximize the recoveries from our properties. We plan to focus on fiscal discipline which includes initiatives implemented to reduce our operating and general and administrative costs. Although our focus is on the exploitation and development of our current asset base, we will evaluate complementary acquisitions 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, 2014:

Areas	Total Proved Reserves (Bcfe) (1)	PV-10 (in millions) (1) (2)	Average daily net production (Mmcfe) (3)
East Texas/North Louisiana	881.2	$ 813.8	238
South Texas (4)	113.1	561.5	39
Appalachia and other	269.5	167.3	55
Total	1,263.8	$ 1,542.6	332

Areas	Estimated drilling locations (5)	Total gross acreage	Total net acreage
East Texas/North Louisiana	1,988	230,600	99,300
South Texas (6)	212	101,400	52,900
Appalachia and other	4,194	659,400	297,100
Total	6,394	991,400	449,300

(1) The total Proved Reserves and PV-10 as of December 31, 2014 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, 2014 and ending on December 1, 2014, of $4.35 per Mmbtu for natural gas and $94.99 per Bbl for oil, in each case adjusted for geographical and historical differentials. The price for NGLs was $33.03 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 due to tax characteristics which can differ significantly among comparable companies. The total Standardized Measure, a measure recognized under GAAP, as of December 31, 2014 was $1.5 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, 2014. 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.

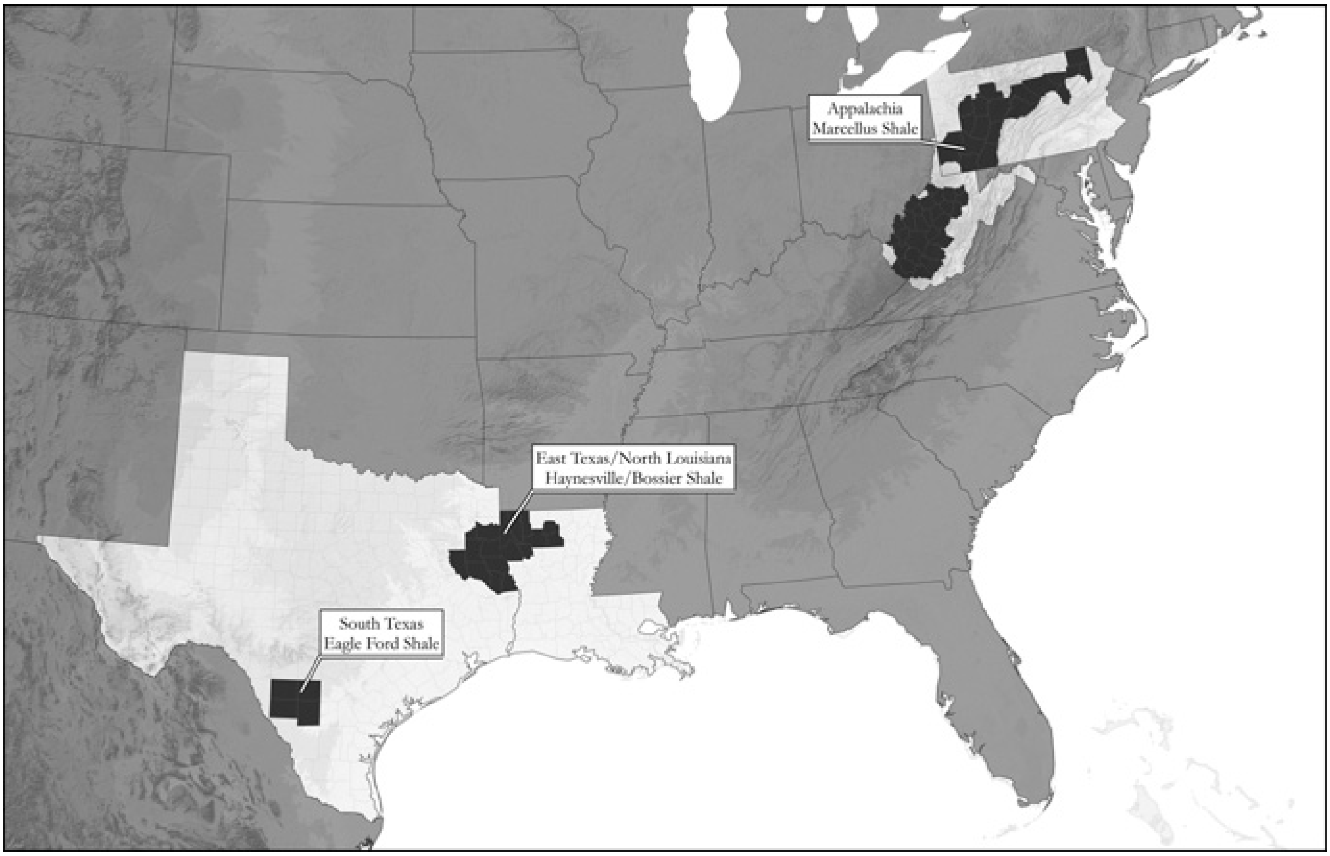
(3) The average daily net production rate was calculated based on the average daily rate during the final month of the year ended December 31, 2014.

(4) We are developing certain undeveloped acreage in the Eagle Ford shale pursuant to the Participation Agreement. Under this agreement, we assign half of our working interest in a well to the joint venture partner 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 acquisitions under the Participation Agreement within our Proved Reserves.

(5) 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. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, drilling results and other factors (see "Item 1A. Risk Factors-Risks Relating To Our Business").

(6) The acreage in this region includes 41,600 net acres outside of our core area in Zavala County that are subject to our joint venture partner's right to participate in each proposed well. The acreage outside of our core area is not subject to the Participation Agreement.

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 6,000 foot laterals in the Holly area of North Louisiana and 6,000 to 8,000 foot laterals in the Shelby area of East Texas. The Bossier shale lies just above certain portions of the Haynesville shale and also contains rich deposits of natural gas.

Our development drilling program in the Haynesville shale is concentrated in the Holly area in DeSoto Parish, Louisiana and the Shelby area in East Texas. At December 31, 2014, we operated three drilling rigs focused on the Haynesville shale. During 2015, we plan to operate an average of three drilling rigs to drill approximately 25 gross (11.9 net) wells and complete approximately 32 gross (17.6 net) wells. The 2015 program will be focused on the development of the Shelby area of East Texas based on the recent success of our drilling program in the area which has resulted in strong well performance. As of December 31, 2014, our average operated shale natural gas production was approximately 589 gross (224.4 net) Mmcfe per day. Including non-operated volumes, our total net production from the Haynesville and Bossier shales was 241.1 Mmcfe per day as of December 31, 2014.

Shelby area

Our position in the Shelby area primarily consists of 31,600 net acres in San Augustine, Sabine, Nacogdoches, and Shelby Counties. This includes approximately 14,400 net acres that were included as part of an acquisition focused on producing properties during 2014 and primarily consists of small undivided interests including a portion that is subject to continuous drilling obligations to hold the acreage. Excluding this recently acquired acreage, approximately 95% of our net acres are held-by-production in the Shelby area. As of December 31, 2014, we had a total of 84 gross (37.1 net) operated horizontal wells flowing to sales. Prior to 2014, our activity in this area consisted of delineating the acreage, establishing infrastructure, performing technical evaluations, testing completion designs and evaluating flowback methodologies. Our drilling program during 2014 was designed to include enhanced completion methods, longer laterals and a more restricted flowback program. As part of our restricted flowback program, we have been managing the choke size to limit the production of the wells to 10 Mmcf or less per day. The restricted flowback program limits the initial production of the wells; however, we anticipate it will increase the estimated ultimate recoveries. The more conservative flowback, along with the other design changes, are yielding strong well performance as evidenced by a minimal reduction in flowing pressures over time. We drilled 8 gross (3.9 net) wells in the area during 2014, which includes 5 gross (2.4 net) operated wells in the Haynesville shale and 3 gross (1.5 net) operated wells in the Bossier shale. We are experiencing strong results from both the Haynesville and Bossier shale wells which resulted in significant upward revisions to our Proved Reserves during 2014, due to improved well performance.

We plan to build on our recent success in the region by drilling 22 gross (9.4 net) wells in the Shelby area during 2015. The drilling program in this region provides attractive rates of return even in a low commodity price environment. We have approximately 250 operated undeveloped locations in this area which provide a platform for future growth.

Holly area

Our position in the Holly area consists of 29,400 net acres in DeSoto Parish and 9,000 net acres in Caddo Parish, which are all held-by-production. At December 31, 2014, we had three drilling rigs running in the area and a total of 397 gross (193.1 net) operated horizontal wells flowing to sales. Our drilling program in the area during 2014 consisted of 39 gross (21.0 net) operated wells drilled in the Haynesville shale based on spacing of four to six wells per section. As of December 31, 2014, we had 48 developed units and 29 undeveloped units. We have also utilized a more restricted flowback program on recent wells turned-to-sales in the area similar to the restricted flowback program that was successful in the Shelby area. We completed 5 gross (2.8 net) refracs on operated wells during 2014 and the wells exhibited strong performance as evidenced by the minimal reduction in production and pressure since the refrac stimulation. The refracs consist of a second fracture stimulation treatment in an existing well to re-stimulate the shale reservoir. This will enhance the connection from the reservoir to the wellbore to increase productivity and more effectively produce the resources. We estimate the cost of the refracs to range from $1.0 million to $2.5 million and we are currently analyzing the results of the tests performed-to-date in order to assess the impact on the recoveries from the wells. We drilled a test well in the Bossier shale in DeSoto Parish in the fourth quarter 2014 to further assess the potential of the formation. We utilized similar enhanced completion methods that have proven to be successful in our recent Haynesville shale development. The well was completed and turned-to-sales in early 2015 and we are currently evaluating the results of the test. The results of our evaluation of the Bossier shale within the Holly area could result in over 300 additional drilling locations.

Our plans for 2015 include drilling 3 gross (2.5 net) wells and completing our inventory of 15 gross (9.2 net) operated wells that have been drilled. We plan to continue to utilize our enhanced completion techniques including more proppant and a restricted flowback program. In addition, we plan to perform 1 gross (0.6 net) refracs on operated wells during 2015.

East Texas/North Louisiana operating effectiveness

We have focused on improving the efficiency of our drilling and completion operations which has resulted in reductions to our well costs. In DeSoto Parish, our average drilling and completion costs per well were $7.1 million during 2014, $7.0 million during 2013 and $8.3 million during 2012. We were able to achieve these reductions in costs while improving our well design through enhanced drilling and completion techniques including more proppant per lateral foot. We continue to achieve improved drilling times per well and are currently averaging 32 days from spud to rig release for a typical 16,500 foot Haynesville well in DeSoto Parish.

In the Shelby area, our average drilling and completion costs per well were $12.1 million during 2014. The average lateral length for these wells was 6,500 feet and represents some of our longest laterals drilled-to-date in the region. During 2015, we expect the average cost per well to decrease as a result of economies of scale in connection with our increased development program and multi-well pad design.

In addition, we believe the current commodity price environment will likely result in the reduction of service costs throughout the industry. We will remain focused on reducing our well costs attributable to drilling while continuing to optimize our completions. We have continued to improve our well design by increasing the amount of proppant used in the hydraulic fracturing process on recent completions. These changes in our well design have improved our well performance and estimated ultimate recoveries. We have implemented several initiatives to enhance and manage our base production in the region. This includes a compression program, foamer injection program and the installation of artificial lift. Our compression program included the installation of two interim lateral compressor units during the year. We recently secured a contract with our midstream service provider for additional compression services in the Holly area which are expected to begin in the third quarter of 2015. We have seen sustained performance improvement from these initiatives as evidenced by a flattening of our base production decline.

Our production operations team is focused on lowering our direct operating costs including water management, efficient utilization of our personnel, equipment rentals and chemicals. We are in the process of negotiating reductions in service costs with certain vendors as a result of the current commodity price environment. Through 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. We plan to continue to efficiently manage our chemical programs which will allow us to reduce costs by minimizing well intervention work.

We have a Dallas-based operations control center that is staffed 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 that included 120 producing wells and undeveloped acreage. Our position in this region includes 52,900 net acres 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 and the total measured depth 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 drilled 63 gross (10.9 net) wells in the core area of Zavala County during the year ended December 31, 2014. Our drilling utilized a multi-well pad design 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. We turned-to-sales 53 gross (9.2 net) wells during the year ended December 31, 2014 within our core area. We drilled 11 gross (5.3 net) wells and turned-to-sales 10 gross (4.2 net) wells outside of our core area during the year ended December 31, 2014. The acreage for the wells drilled outside of our core area was primarily earned through a farmout agreement and additional leasing which has allowed us to expand our position in the region. The wells drilled outside of the core area are not included as part of the acquisition program under the Participation Agreement with our joint venture partner and typically have a higher working interest compared to new wells drilled in our core area. The most recent wells turned-to-sales both inside and outside our core area featured enhanced completion methods and have provided our best results to date in the region. As of December 31, 2014, our average operated shale oil production was approximately 23,100 gross (6,200 net) barrels of oil per day from 209 gross (107.7 net) wells.

We have reduced our drilling activity in South Texas in response to lower crude oil prices and plan to average one rig throughout 2015. Our 2015 capital program is designed to preserve leasehold commitments, fulfill continuous drilling obligations and drill key test wells in the Buda formation. We plan to spend a total of $66.0 million in this region during 2015, of which $59.0 million will be spent to spud 23 gross (7.1 net) horizontal wells and turn to sales 44 gross (10.7 net) horizontal wells. We plan to turn-to-sales 33 gross (5.7 net) Eagle Ford shale horizontal wells in our core area acreage, and 11 gross (5.0 net) horizontal well outside of our core area. Our plans for 2015 include 1 gross (0.5 net) operated well and 3 gross (0.5 net) non-operated wells drilled in the Buda formation. The Buda formation has the potential to add drilling locations to our inventory characterized by low capital intensity with high rates of return. The average cost per well in the Buda formation as part of our 2015 capital program range from $2.5 million to $3.5 million and do not require hydraulic fracturing since the formation contains natural fractures. Our capital program during 2015 also includes $7.0 million to fund pumping units to optimize our production and infrastructure development to reduce future operating costs.

South Texas operational effectiveness

We have utilized our expertise from other shale developments and have realized significant operational efficiencies in our Eagle Ford assets. This includes improved drilling times per well which are currently averaging 12 days from spud to rig release and the current average drilling and completion costs per well are approximately $7.1 million. Additionally, we recently secured a completion contract that will further reduce our fracture stimulation costs. We continue to implement initiatives to optimize and increase the efficiency of our production including the installation of artificial lift. We installed 87 additional pumping units during 2014 and plan to install 57 units during 2015. The pumping units installed to-date have been successful in flattening our base production decline.

We engaged a third party to construct central production facilities in our core area to increase the efficiency of our production. These facilities will also reduce our costs during the completion phase of certain properties since multiple wells on a pad will utilize the same connections to the central facilities. The first and second central production facilities became operational in the fourth quarter of 2014 and we began production from wells connected to this system. As of December 31, 2014, these central facilities have allowed us to produce 27 gross (5.5 net) wells into the system. The third central production facility became operational in the first quarter of 2015. A pipeline is currently being constructed from the central facilities to an oil pipeline in Dilley, Texas and is expected to be operational in the second quarter or third quarter of 2015. We are evaluating the design of an electrical distribution network over the core development area that will provide a more efficient cost structure to operate the field. We were also able to significantly reduce our operating costs in the region during 2014 through the execution of several initiatives including decreased saltwater disposal costs and reduced reliance on third-party contractors. We plan to implement additional cost reduction initiatives during 2015 and expect a reduction in our service costs as a result of the current commodity price environment. We have already negotiated reductions in service costs with certain key vendors including rental equipment and chemical treating programs.

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 157,000 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, 29,900 net acres are scheduled to expire prior to 2018. As of December 31, 2014, we operated a total of 5,736 gross (2,708.1 net) vertical shallow wells flowing to sales with an average gross production rate of approximately 29 gross (11.9 net) Mmcfe per day. As of December 31, 2014 we operated a total of 126 gross (45.7 net) horizontal wells in the Marcellus shale with an average gross production rate of approximately 141 gross (38.6 net) Mmcfe per day. Including non-operated volumes, our net production in the Appalachia region was 52.5 Mmcfe per day as of December 31, 2014.

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

We previously suspended 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. A significant amount of our acreage is held-by-production, which allows us to control the timing of the development of this region. We are encouraged by the recent results of our wells turned-to-sales in this region and will be resuming our appraisal drilling program in 2015. Our plans for 2015 include the drilling of 2 gross (0.7 net) operated appraisal wells in Sullivan County targeting the Marcellus shale near recent successful results. These successful results include our most recent well turned-to-sales in October 2013 which had cumulative production of 2.7 Bcfe as of December 31, 2014. We have an extensive inventory of undeveloped locations prospective for the Marcellus shale that would provide attractive rates of return in an improved commodity price environment. We have the ability to wait for the optimal time to develop these locations since most of the prospective acreage is held-by-production.

Marcellus shale operational effectiveness

We have effectively managed our base production declines as a result of increased automation and surveillance equipment to reduce downtime as well as artificial lift installations. We recently restructured our field organization to better align the operations personnel with the asset base and reduce our operating costs.

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 the Eagle Ford shale in South Texas, Haynesville and Bossier shales in East Texas/North Louisiana and Marcellus shale in the Appalachia region. Predominantly all of our Proved Reserves are associated with shale assets in these areas.

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: 15-25% in the Haynesville and Bossier shale formation; 30-40% in the Eagle Ford shale formation; and 25-35% in the Marcellus shale formation.

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, see "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, 2014 were approximately 1.3 Tcfe, of which approximately 96% were related to our shale properties. Of our Proved Reserves attributed to shale properties, approximately 69% were located in the Haynesville/Bossier shale, 18% in the Marcellus shale and 9% in the Eagle Ford shale. Our non-shale Proved Reserves represented approximately 4% of total Proved Reserves as of December 31, 2014, which consisted primarily of conventional assets in the Appalachia region.

The following table summarizes Proved Reserves as of December 31, 2014, 2013 and 2012. This information was prepared in accordance with the rules and regulations of the SEC. The comparability of our reserves is impacted by purchases and sales of reserves in place, production, revisions of previous estimates and discoveries and extensions. See "Management's discussion and analysis of oil and natural gas reserves" for a summary of the changes in our Proved Reserves.

	As of December 31,		
	2014	2013	2012
Oil (Mbbls)			
Developed	14,429	11,274	4,371
Undeveloped	3,258	4,104	1,199
Total	17,687	15,378	5,570
Natural gas (Mmcf)			
Developed	502,314	657,116	917,326
Undeveloped	652,714	359,363	18,806
Total	1,155,028	1,016,479	936,132
Natural gas liquids (Mbbls)			
Developed	387	2,088	4,784
Undeveloped	54	495	1,855
Total	441	2,583	6,639
Equivalent reserves (Mmcfe)			
Developed	591,210	737,291	972,256
Undeveloped	672,586	386,954	37,130
Total	1,263,796	1,124,245	1,009,386
PV-10 (in millions) (1)			
Developed	$ 1,117.6	$ 1,153.5	$ 666.0
Undeveloped	425.0	98.8	30.1
Total	$ 1,542.6	$ 1,252.3	$ 696.1
Standardized Measure (in millions) (2)	$ 1,542.6	$ 1,252.3	$ 696.1

(1) 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 NGL price was computed using the trailing 12 month average of realized prices.

	Average spot prices		
	Oil (per Bbl)	Natural gas (per Mmbtu)	Natural gas liquids (per Bbl)
December 31, 2014	$ 94.99	$ 4.35	$ 33.03
December 31, 2013	96.78	3.67	39.92
December 31, 2012	94.71	2.76	46.57

(2) There is no difference in Standardized Measure and PV-10 for all years presented 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.

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 their audit of the Proved Reserves prepared by EXCO's internal engineers. Our Vice President of Engineering is a registered Professional Engineer with over 36 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 as of December 31, 2014, 2013 and 2012 have been prepared by Lee Keeling. 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, 2014 and 2013. Our estimated Proved Reserves and future net cash flows for our shale properties in all regions except South Texas were prepared by NSAI as of December 31, 2014 and 2012, and were prepared by our internal engineers and audited by NSAI as of December 31, 2013. Lee Keeling, 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.

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 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 18. 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, 2014 and changes in our Proved Reserves during 2014. This discussion and analysis should be read in conjunction with “Note 18. 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, 2014 to December 31, 2014.

	Oil (Mbbls)	Natural gas (Mmcf)	Natural gas liquids (Mbbls)	Equivalent natural gas (Mmcfe)
Proved Developed Reserves	14,429	502,314	387	591,210
Proved Undeveloped Reserves	3,258	652,714	54	672,586
Total Proved Reserves (1)	17,687	1,155,028	441	1,263,796
The changes in reserves for the year are as follows:				
January 1, 2014	15,378	1,016,479	2,583	1,124,245
Purchases of reserves in place	—	7,316	—	7,316
Discoveries and extensions	4,164	69,902	107	95,528
Revisions of previous estimates (2):				
Changes in price	45	167,302	127	168,334
Other factors	1,737	120,850	(8)	131,224
Sales of reserves in place	(1,401)	(105,841)	(2,144)	(127,111)
Production	(2,236)	(120,980)	(224)	(135,740)
December 31, 2014	17,687	1,155,028	441	1,263,796

(1) Total Proved Reserves quantities on a per Mcfe basis are comprised of 91% natural gas, 8% oil, and 1% NGLs. Our future cash inflows from our total Proved Reserves as of December 31, 2014 were comprised of 74% natural gas and 26% oil.

(2) Revisions of previous estimates include both reserves in place at the beginning of the year, acquisitions and divestitures during the year. There were no reclassifications of Proved Undeveloped Reserves to unproved reserves during 2014 pursuant to the five year development rule established by the SEC.

Purchases of reserves in place

Purchases of reserves in place consisted primarily of our acquisition of certain proved developed producing properties in the Shelby area of East Texas. 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 2014 were 95.5 Bcfe which were primarily due to 48.7 Bcfe, 26.2 Bcfe and 19.7 Bcfe of discoveries and extensions from our Haynesville shale, Eagle Ford shale and Bossier shale, respectively. The discoveries and extensions in the Haynesville and Bossier shales were primarily due to our development of the Shelby area of East Texas. The discoveries and extensions in the Eagle Ford shale were due to continued development of our core area as well as the development of properties as part of a farm-out agreement outside of our core area.

Revisions of previous estimates

Our revisions of previous estimates included upward revisions to our Proved Reserve quantities of 168.3 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 prices prescribed by the SEC. This change in price was primarily driven by the increase in the trailing 12 month average of natural gas prices from $3.67 per Mmbtu for the year-ended December 31, 2013 to $4.35 per Mmbtu for the year ended December 31, 2014. As a result of the recent decline in oil and natural gas prices, we expect downward revisions to our Proved Reserve quantities in 2015 if prices do not increase. The decrease in price could shorten the economic life of our properties or result in the reclassification of Proved Undeveloped properties to unproved properties if they are not economical when using prices prescribed by the SEC.

Our revisions of previous estimates also included 131.2 Bcfe upward revisions due to performance and other factors. This included 67.1 Bcfe of upward revisions in the Shelby area based on improved well performance as a result of enhanced completion methods including more proppant, longer laterals and a more restricted flowback. The upward revisions also included 45.9 Bcfe from our Appalachia region based on additional historical results incorporated to our reserve estimates which indicated a shallower decline than previously forecasted and improvements to our well design including longer laterals which improved our recoveries.

Sales of reserves in place

Sales of reserves in place primarily consisted of our proportionate share of conventional properties held by Compass which closed on October 31, 2014. 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 2014 was 135.7 Bcfe, which included approximately 3.3 Bcfe in production from extensions and discoveries that were not reflected in our Proved Reserves at January 1, 2014.

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, 2014:

	Mmcfe
Proved Undeveloped Reserves at January 1, 2014	386,954
Purchases of Proved Undeveloped Reserves in place	—
Sales of Proved Undeveloped Reserves	(4,526)
New discoveries and extensions (1)	63,018
Proved Undeveloped Reserves transferred to developed (2)	(71,776)
Proved Undeveloped Reserves transferred to unproved (3)	—
Other revisions of previous estimates of Proved Undeveloped Reserves (4)	298,916
Proved Undeveloped Reserves at December 31, 2014	672,586

(1) Approximately 64%, 18% and 18% of the discoveries and extensions of Proved Undeveloped Reserves in 2014 occurred in the Haynesville shale, Bossier shale and Eagle Ford shale, respectively. The discoveries and extensions in the Haynesville and Bossier shales were primarily due to our development of the Shelby area of East Texas.

(2) Approximately 91% and 9% of the Proved Undeveloped Reserves transferred to Proved Developed Reserves were in the Haynesville shale and Eagle Ford shale, respectively. Capital costs incurred to convert Proved Undeveloped Reserves to Proved Developed Reserves were $132.9 million.

(3) Represents Proved Undeveloped Reserves that were reclassified to unproved pursuant to the five year development rule established by the SEC. We did not reclassify any Proved Undeveloped Reserves to unproved reserves during 2014.

(4) The other revisions of previous estimates included upward revisions due to price of 159.8 Bcfe and upward revisions due to performance and other factors of 118.9 Bcfe. The revisions due to price primarily related 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. The revisions due to performance and other factors primarily consisted of improved well performance in Haynesville and Bossier shale wells in the Shelby area of East Texas and Marcellus shale wells in the Appalachia region.

Impacts of changes in reserves on depletion rate and statements of operations in 2014

Our depletion rate increased to $1.90 per Mcfe in 2014 from $1.47 per Mcfe in 2013. The increase was primarily due to the acquisition of assets in the Haynesville and Eagle Ford shales during the third quarter of 2013 which increased our depletable base. The oil producing assets in the Eagle Ford shale result in a higher depletion rate when calculated on a per Mcfe basis compared to the rest of our properties.

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)	**2014**	**2013**	**2012**
Revenues, production and prices:			
Oil:			
Revenue	$ 196,316	$ 111,440	$ 62,119
Production sold (Mbbls)	2,236	1,188	704
Average sales price per Bbl	$ 87.80	$ 93.80	$ 88.24
Natural gas:			
Revenue	$ 457,946	$ 514,309	$ 462,422
Production sold (Mmcf)	120,980	153,321	182,644
Average sales price per Mcf	$ 3.79	$ 3.35	$ 2.53
Natural gas liquids:			
Revenue	$ 6,007	$ 8,560	$ 22,068
Production sold (Mbbls)	224	243	510
Average sales price per Bbl	$ 26.82	$ 35.23	$ 43.27
Costs and Expenses:			
Oil and natural gas operating costs per Mcfe	$ 0.47	$ 0.38	$ 0.41

We had two fields that exceeded 15% of our total Proved Reserves as of December 31, 2014. The Holly field and Shelby field represented approximately 53% and 16% of our total Proved Reserves, respectively. The following table provides additional information related to our Holly and Shelby fields:

	Year Ended December 31,		
	2014	**2013**	**2012**
Holly field:			
Natural gas production sold (Mmcf)	82,299	107,746	111,629
Average price per Mcf	$ 4.02	$ 3.39	$ 2.47
Oil and natural gas operating costs per Mcf	0.22	0.13	0.11
Shelby field:			
Natural gas production sold (Mmcf)	10,314	12,020	24,764
Average price per Mcf	$ 3.90	$ 3.32	$ 2.48
Oil and natural gas operating costs per Mcf	0.33	0.28	0.17

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, 2014					
	Gross wells (1)			Net wells		
	Oil	Natural gas	Total	Oil	Natural gas	Total
Producing region:						
East Texas/North Louisiana	—	691	691	—	246.6	246.6
South Texas	220	5	225	108.0	2.2	110.2
Appalachia and other	338	5,812	6,150	165.2	2,629.9	2,795.1
Total	558	6,508	7,066	273.2	2,878.7	3,151.9

(1) As of December 31, 2014, we held interests in 1 gross well with multiple completions.

As of December 31, 2014, we operated 6,559 gross (3,095.4 net) wells, which represented approximately 93% 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 properties acquired 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, 2014, we had 8 gross (3.3 net) wells being drilled and 40 gross (14.7 net) wells being completed or awaiting completion.

	Development wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2014 (1)	98	—	98	29.6	—	29.6
Year ended December 31, 2013	105	2	107	48.7	0.5	49.2
Year ended December 31, 2012	169	2	171	73.8	1.9	75.7

	Exploratory wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2014 (1)	—	—	—	—	—	—
Year ended December 31, 2013 (2)	15	—	15	7.7	—	7.7
Year ended December 31, 2012 (3)	6	—	6	2.2	—	2.2

(1) We did not complete any exploratory wells in 2014, but did initiate the drilling of one exploratory well in the Bossier shale in North Louisiana late in 2014. Our development wells in 2014 included the Haynesville and Bossier shales in DeSoto Parish, Louisiana, and the Shelby area of East Texas. Our development wells also included the Eagle Ford shale in our core area in Zavala County, Texas and certain wells outside our core area as part of a farmout agreement. The wells outside of our core area are considered development wells as a result of a successful drilling program in this area in 2014.

(2) Exploratory wells in 2013 included certain wells drilled in the Eagle Ford shale under the farmout agreement outside of our core area in Zavala County, Texas and certain wells in the Marcellus shale in Jefferson, Clarion and Sullivan Counties, Pennsylvania.

(3) Exploratory wells in 2012 include certain wells drilled in the Marcellus shale formation in Jefferson and Sullivan Counties, Pennsylvania.

Our developed and undeveloped acreage

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

	At December 31, 2014			
	Developed		Undeveloped	
Area	Gross	Net	Gross	Net
East Texas/North Louisiana	149,700	71,700	80,900	27,600
South Texas	93,500	48,100	7,900	4,800
Appalachia	397,300	181,000	253,500	109,000
Other	4,400	3,200	4,200	3,900
Total	644,900	304,000	346,500	145,300

The primary term of our oil and natural gas leases expire at various dates. Most of our undeveloped acreage is held-by-production, which means that these leases are active as long as we produce oil or natural gas from the acreage or comply with certain lease terms. Upon ceasing production, these leases will expire. We have 22,100, 9,600 and 5,000 net acres with leases expiring in 2015, 2016 and 2017, respectively. In addition, we have 11,500 net acres that are subject to continuous drilling obligations which are primarily located in the Shelby area of East Texas. Predominantly all of our 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 2014, sales to BG Energy Merchants LLC and Chesapeake Energy Marketing Inc. accounted for approximately 34% and 31%, respectively, of our 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 Energy Corporation ("Chesapeake"). The loss of any significant customer may cause a temporary interruption in sales of, or lower price for, our oil and natural gas production. 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. Laws and regulations affecting the oil and natural gas industry are 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 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, including Louisiana and Texas, 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 or produced 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 (and our) profitability.

FERC and CFTC matters

The availability, terms and cost of downstream transportation significantly affect sales of natural gas, oil and NGLs. The interstate transportation of natural gas, including regulation of the terms, conditions and rates for interstate transportation and storage of natural gas, is subject to federal regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act ("NGA"). Transportation rates under the NGA must be just and reasonable. Since 1985, FERC has implemented regulations intended to increase competition within the natural gas industry by requiring that interstate natural gas transportation be made available on an open-access, not unduly discriminatory basis. FERC's jurisdiction under the NGA excludes gathering and distribution of natural gas, so gathering and distribution of natural gas are subject to regulation by individual state laws. State regulations also govern the rates and terms for access to, and transportation of natural gas on, intrastate pipeline facilities (while intrastate pipelines may from time to time provide specific services that are subject to limited regulation by FERC). The interstate transportation of oil and NGLs, including regulation of the rates, terms and conditions of service, is subject to federal regulation by FERC under the Interstate Commerce Act. Rates for such oil and NGLs transportation must be just and reasonable and not unduly discriminatory. Oil and NGLs 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 markets and enforce anti-market manipulation regulations with respect to the physical and financial (futures, options and swaps) 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 and rail transportation

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 law 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 ("ANPR") regarding pipeline safety. As described in the ANPR, 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. If revisions to gathering line regulations are enacted by PHMSA as a result of such ANPR, we could incur significant expenses.

Any transportation of the Company's crude oil or natural gas liquids by rail is also subject to regulation by the DOT's PHMSA and the DOT's Federal Railroad Administration ("FRA") under the Hazardous Materials Regulations at 49 CFR Parts 171-180 ("HMR"), including Emergency Orders by the FRA and new regulations being proposed by the PHMSA, arising due to the consequences of train accidents and the increase in the rail transportation of flammable liquids.

In September 2013, the PHMSA issued a final rule updating its regulations to increase the maximum civil penalty from $100,000 to $200,000 for each violation for each day the violation continues, and to increase from $1,000,000 to $2,000,000 the limitation that the maximum administrative civil penalty may not exceed for any related series of violations.

U.S. federal taxation

Federal income tax laws significantly affect our operations. The principal provisions that affect us are those that permit us, subject to certain limitations, to deduct as incurred, rather than to capitalize and amortize, our share of the domestic "intangible drilling and development costs" and to claim depletion on a portion of our domestic oil and natural gas properties (up to an aggregate of 1,000 Bbls per day of domestic crude oil and/or equivalent units of domestic natural gas). Further, 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 natural 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. Non-exempt waste is subject to more rigorous and costly disposal requirements.

Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. The CAA and analogous state laws require certain new and modified sources of air pollutants to obtain permits prior to commencing construction. Smaller sources may qualify for exemption from permit requirements 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.

More stringent laws and regulations protecting the environment may be adopted in the future and we may be required to incur material expenses to comply with them. 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.

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 we were to have a portion of our 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. Predominantly all of our undeveloped properties 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. Many states have considered or adopted legislation regulating hydraulic fracturing, including the disclosure of chemicals used in the process. 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; a final draft has not been released. 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

To the extent not preempted by other applicable laws, we are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes, where applicable. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes, where applicable, require that we maintain 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 real property and/or mineral records. We will conduct title investigations and, in most cases, obtain a title opinion of local counsel for the drill site 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 explosions, 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 automobile liability, 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 automobile and 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 automobile and general liability insurance per occurrence limit is reached. Further, we currently carry $65 million of pollution coverage and $30 million of cost of well control (blowout) coverage with deductibles ranging from $100,000 to $500,000.

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 generally will not cover fines and penalties. Further, these policies may not cover the costs and expenses related to government-mandated environmental clean-up responsibilities, or may do so on a limited basis.

Our employees

As of December 31, 2014, we employed 558 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,” “potential,” “project,” “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 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, including our ability to maintain compliance with our debt covenants;
- disruption of credit and capital markets and the ability of financial institutions to honor their commitments;
- estimates of reserves and economic assumptions, including estimates related to acquisitions and dispositions of oil and natural gas properties;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- exploratory risks, including those related to our activities in shale formations;
- 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 and other materials for drilling and completion 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;
- our ability to attract and retain key personnel, including our search for a chief executive officer;
- 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 shares.

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 and other sources. 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 the 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, 2014, approximately 91% of our Proved Reserves were natural gas and approximately 89% 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;
- federal regulations generally prohibiting the export of U.S. crude oil;
- federal regulations applicable to the export of, and construction of export facilities for natural gas and NGLs.
- 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 2014, the NYMEX price for natural gas fluctuated from a high of $6.15 per Mmbtu to a low of $2.89 per Mmbtu, while the NYMEX West Texas Intermediate crude oil price ranged from a high of $107.26 per Bbl to a low of $53.27 per Bbl. For the five years ended December 31, 2014, the NYMEX Henry Hub natural gas price ranged from a high of $6.15 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 $53.27 per Bbl. On December 31, 2014, the spot market price for natural gas at Henry Hub was $2.89 per Mmbtu, a 32% decrease from December 31, 2013. On December 31, 2014, the spot market price for crude oil at Cushing was $53.27 per Bbl, a 46% decrease from December 31, 2013. For 2014, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were $87.80 per Bbl and $3.79 per Mcf, respectively, compared with 2013 average realized prices of $93.80 per Bbl and $3.35 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 from 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 2014, this differential ranged from a high of $7.93 per barrel to a low of $2.21 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 2014 ranged from a low of NYMEX less $1.32 per Mmbtu to a high of NYMEX less $2.94 per Mmbtu. These differentials vary depending on factors such as supply, demand, pipeline capacity, infrastructure, and weather.

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 production. 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 our producing regions 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 our shale properties, 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 and the value of our common shares.

We have entered into marketing agreements with third-parties to sell a significant percentage of our anticipated oil and natural gas production in the East Texas/North Louisiana and South Texas regions. If these third-parties are unable or otherwise fail to market the oil and natural gas we produce, 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 production or have a material adverse effect on our business, results of operations or financial condition.

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. In addition, the loss of any significant customer may cause a temporary interruption in sales of, or a lower price for, our oil and natural gas.

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 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.

We have entered into an agreement to deliver an aggregate minimum volume commitment of natural gas production from the Holly and Shelby fields to certain gathering systems over a five year period. If there is a shortfall to the minimum volume commitment in any year, then we are severally responsible with a joint venture partner to pay fixed amounts of money to the gatherer regardless of quantities actually produced in to the systems.

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.

We anticipate the deliveries of natural gas in future periods will not meet the minimum quantities set forth in certain of these agreements and will require us to make payments for the shortfall below the minimum quantities. 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.

There are risks associated with our drilling activity that could impact 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.

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 and sand used in our drilling and hydraulic fracturing activities. All of these risks could adversely affect our results of operations and financial condition.

The results of our drilling in new or emerging formations, including our properties in shale formations, 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. 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. We plan to implement several initiatives to manage our base production and minimize the decline from our shale properties. If these initiatives are not successful and we are required to incur significant expenditures to manage our base production, this could negatively impact our production and cash flows from operations.

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.

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.

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. Furthermore, the actions taken by other working interest owners could prevent or alter our development plans.

We conduct a substantial portion of our operations through joint ventures with third parties, principally BG Group and Kohlberg Kravis Roberts & Co. L.P. ("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.

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.

The owners of working interests may not consent to the development of certain properties that we operate which may require us to assume their share of the working interest during the development and a period after the well is on production. This may require us to expend additional capital not already anticipated as part of our development plans and assume additional risks associated with the development and future performance of the properties. The owners of working interests in certain properties that we operate may also hold rights within the respective operating agreements that could prevent us from performing additional development activities on the properties such as recompletions and other workovers without their consent.

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 exploratory drilling are the main methods of replacing reserves. However, development and exploratory 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. The planned reduction in our development program in 2015 compared to prior years could negatively impact our ability to replace our reserves in the future.

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.

If we are unable to complete the joint development of our assets in the Eagle Ford shale formation 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, we will assign half of our undivided 50% interest in such well to KKR such that KKR will fund and own 75% of each well drilled and we 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 through acquisitions of KKR's producing properties.

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 shares.

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 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 shares.

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.

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 year ended December 31, 2014, we did not recognize any impairments to our proved oil and natural gas properties. For the years ended December 31, 2013 and 2012, we recognized impairments of $108.5 million and $1.3 billion, 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. As a result of recent decline in oil and natural gas prices, we expect to recognize additional impairments to our oil and natural gas properties in 2015 if prices do not increase.

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, 2014, 2013 and 2012.

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 earthquakes, 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 2016 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 natural 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 natural gas companies; increase in the geological and geophysical amortization period for independent producers. 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.

In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions; although the Supreme Court struck down the permitting requirements, it upheld the EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants. 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. The EPA recently announced its intention to take measures to require or encourage reductions in methane emissions, including from oil and natural gas operations. The measures include the development of NSPS regulations in 2016 for reducing methane from new and modified oil and natural gas production sources and natural gas processing and transmission sources. 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.

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. Many states have adopted or are considering legislation regulating hydraulic fracturing, including the disclosure of chemicals used in the process. 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 asserted 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 were expected in 2012; although final results are not yet available. 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 has 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. Additionally, the EPA recently announced its intention to take measures to require or encourage reductions in methane emissions, including from oil and natural gas operations. The measures include the development of NSPS regulations in 2016 for reducing methane from new and modified oil and natural gas production sources and natural gas processing and transmission sources. 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.

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.

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

We have been engaged in a search for a new chief executive officer since November 2013. To the extent there is a further 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 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 year ended December 31, 2014 we paid cash settlements on our derivative financial instrument contracts totaling $19.0 million and during the year ended December 31, 2013, we received cash receipts of $42.1 million. For the year ended December 31, 2014, 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 $94.1 million. As of December 31, 2014, our oil and natural gas derivative financial instrument contracts were in the net asset position of $98.5 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.

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 shares immediately prior to the ownership change multiplied by the long term tax-exempt interest rate, which is published monthly by the Internal Revenue Service ("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 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.

Risks relating to our indebtedness

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

As of December 31, 2014 we had approximately $1.5 billion of indebtedness, including $202.5 million of indebtedness subject to variable interest rates and $750.0 million and $500.0 million of indebtedness under the 2018 Notes and 2022 Notes, respectfully. Our total interest expense, excluding amortization of deferred financing costs, on an annual basis based on currently available interest rates would be approximately $102.6 million and would change by approximately $2.0 million for every 1% change in interest rates.

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

- it may be more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the EXCO Resources Credit Agreement or the indenture governing the 2018 Notes and 2022 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 Participation Agreement with KKR), 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, 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, 2022 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, 2022 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. The borrowing base redetermination process considers assumptions related to future commodity prices; therefore, our borrowing capacity could be negatively impacted by further declines in oil and natural gas prices. This was evidenced by our recent borrowing base redetermination in February 2015 which reduced the borrowing base to $725.0 million primarily as a result of the recent declines in commodity prices as compared to commodity prices at the time of the prior borrowing base redetermination. 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 and 2022 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 and 2022 Notes or our other indebtedness, our joint ventures and subsidiaries do not have any obligation to pay amounts due on the 2018 Notes and 2022 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 and 2022 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 shares;

- 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 certain financial covenants. Our ability to comply with these financial covenants may be affected by events beyond our control, and, as a result, we may be unable to meet these financial covenants. These financial covenants 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 covenants could result in an event of default under the applicable indebtedness. When oil and/or natural gas prices decline for an extended period of time, our ability to comply with these covenants 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 Shares

Our common share price may fluctuate significantly.

Our common shares trade on the NYSE but an active trading market for our common shares may not be sustained. The market price of our common shares 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 share 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 shares. In addition, the stock markets in general can experience considerable price and volume fluctuations.

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

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

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 shares.

As of December 31, 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 common shares. 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 our common shares. 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 common shares 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 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 (1)...	155,000	$ 253,826	May 31, 2025
Cranberry Township, Pennsylvania..................	15,400	$ 22,500	December 31, 2017

(1) The office lease in Dallas, Texas contains a right on our behalf to terminate the lease agreement early on June 30, 2020 or June 30, 2022.

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 shares

Our common shares trade 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 share as reported by the NYSE:

	Price per share		
	High	Low	Dividends Declared
2014			
First Quarter	$ 5.85	$ 4.60	$ 0.05
Second Quarter	6.60	5.05	0.05
Third Quarter	5.95	3.25	0.05
Fourth Quarter	3.80	1.98	—
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

Our shareholders

According to our transfer agent, Continental Stock Transfer & Trust Company, there were 253 holders of record of our common shares on December 31, 2014 (including nominee holders such as banks and brokerage firms who hold shares for beneficial holders and holders of restricted shares).

Our dividend policy

On December 15, 2014, our board of directors suspended our cash dividend to provide additional funds to reinvest into the Company and did not approve a cash dividend for the fourth quarter 2014. In 2014, we paid cash dividends of $0.15 per share, or $0.05 per share for each of the first three quarters, totaling $41.1 million. Any future declaration of dividends, as well as the establishment of record and payment dates, will depend on our earnings, capital requirements, financial condition, prospects and other factors our board of directors may deem relevant.

Issuer repurchases of common shares

The following table details our repurchases of common shares for the three months ended December 31, 2014:

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) (2)
October 1 - October 31	—	$ —	—	$ 192.5
November 1 - November 30	32,011	3.78	—	192.5
December 1 - December 31	6,810	2.24	—	192.5
Total	38,821	3.51	—	

(1) Represents shares that were tendered by employees to satisfy minimum tax withholding amounts for the vesting of restricted share awards.
(2) 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

(in thousands, except per share amounts)	Year Ended December 31, 2014	2013	2012	2011	2010
Statement of operations data (1):					
Revenues:					
Oil and natural gas	$ 660,269	$ 634,309	$ 546,609	$ 754,201	$ 515,226
Cost and expenses:					
Oil and natural gas production (2)	94,326	83,248	104,610	108,641	108,184
Gathering and transportation	101,574	100,645	102,875	86,881	54,877
Depletion, depreciation and amortization	263,569	245,775	303,156	362,956	196,963
Impairment of oil and natural gas properties	—	108,546	1,346,749	233,239	—
Accretion of discount on asset retirement obligations	2,690	2,514	3,887	3,652	3,758
General and administrative (3)	65,920	91,878	83,818	104,618	105,114
(Gain) loss on divestitures and other operating items (4)	5,315	(177,518)	17,029	23,819	(509,872)
Total cost and expenses	533,394	455,088	1,962,124	923,806	(40,976)
Operating income (loss)	126,875	179,221	(1,415,515)	(169,605)	556,202
Other income (expense):					
Interest expense, net	(94,284)	(102,589)	(73,492)	(61,023)	(45,533)
Gain (loss) on derivative financial instruments (5)	87,665	(320)	66,133	219,730	146,516
Other income (expense)	241	(828)	969	788	327
Equity income (loss) (6)	172	(53,280)	28,620	32,706	16,022
Total other income (expense)	(6,206)	(157,017)	22,230	192,201	117,332
Income (loss) before income taxes	120,669	22,204	(1,393,285)	22,596	673,534
Income tax expense	—	—	—	—	1,608
Net income (loss)	$ 120,669	$ 22,204	$(1,393,285)	$ 22,596	$ 671,926
Basic net income (loss) per share	$ 0.45	$ 0.10	$ (6.50)	$ 0.11	$ 3.16
Diluted net income (loss) per share	$ 0.45	$ 0.10	$ (6.50)	$ 0.10	$ 3.11
Cash dividends declared per share	$ 0.15	$ 0.20	$ 0.16	$ 0.16	$ 0.14
Weighted average common shares and common share equivalents outstanding:					
Basic	268,258	215,011	214,321	213,908	212,465
Diluted	268,376	230,912	214,321	216,705	215,735
Statement of cash flow data:					
Net cash provided by (used in):					
Operating activities	$ 362,093	$ 350,634	$ 514,786	$ 428,543	$ 339,921
Investing activities	(221,588)	(252,478)	(427,094)	(709,531)	(712,854)
Financing activities	(144,683)	(93,317)	(74,045)	268,756	348,755
Balance sheet data:					
Current assets	$ 330,766	$ 305,854	$ 361,866	$ 678,008	$ 520,460
Total assets	2,356,896	2,408,628	2,323,732	3,791,587	3,477,420
Current liabilities	365,371	349,170	237,931	287,399	285,698
Long-term debt	1,446,535	1,858,912	1,848,972	1,887,828	1,588,269
Shareholders' equity	510,004	147,905	149,393	1,558,332	1,540,552
Total liabilities and shareholders' equity	2,356,896	2,408,628	2,323,732	3,791,587	3,477,420

(1) We have completed numerous acquisitions and dispositions which impact the comparability of the selected financial data between periods.
(2) 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 and $1.0 million for the years ended December 31, 2011 and 2010, respectively. We had no share-based compensation included in oil and natural gas production costs for the years ended December 31, 2014, 2013 and 2012.
(3) Share-based compensation calculated pursuant to ASC 718 included in general and administrative expenses was $5.0 million, $10.7 million, $8.9 million, $10.9 million and $15.8 million for the years ended December 31, 2014, 2013, 2012, 2011 and 2010, respectively.
(4) During 2013, we recognized a gain on the contribution of properties to Compass. During 2010, we recognized gains on the sale transactions attributable to the formation of our joint ventures with BG Group.
(5) We do not designate our derivative financial instruments as hedges and, as a result, the changes in the fair value of our derivative financial instruments are recognized in our Consolidated Statements of Operations. See "Note 2. Summary of significant accounting policies" in the Notes to our Consolidated Financial Statements for a description of this accounting method.
(6) 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.

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 maintaining 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

Rights Offering

We closed a Rights Offering and related private placement of our common shares on January 17, 2014 which resulted in the issuance of 54,574,734 shares of common shares for gross proceeds of $272.9 million. In connection with the Rights Offering, we entered into investment agreements ("Investment Agreements") with certain affiliates of WL Ross and Hamblin Watsa Investment Counsel Ltd. ("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 elected to exercise their over-subscription privilege. In connection with the Rights Offering and related transactions under the Investment Agreements, 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 reduce outstanding indebtedness under the EXCO Resources Credit

Agreement, including the remainder of the asset sale requirement as well as a portion of the indebtedness outstanding under the revolving commitment.

Permian Basin transaction

On March 24, 2014, we closed a purchase and sale agreement with a private party for the sale of our interest in certain non-operated assets in the Permian Basin including producing wells and undeveloped acreage for approximately $68.2 million, after final purchase price adjustments. The effective date of the transaction was January 1, 2014. Proceeds from the sale were used to reduce outstanding indebtedness under the EXCO Resources Credit Agreement.

2022 Notes

On April 16, 2014, we completed a public offering of $500.0 million in aggregate principal amount of the 2022 Notes. We received net proceeds of approximately $490.0 million after offering fees and expenses. The 2022 Notes bear interest at a rate of 8.5% per annum, payable in arrears on April 15 and October 15 of each year. We used the net proceeds from the 2022 Notes to repay indebtedness under the EXCO Resources Credit Agreement, including the $297.8 million outstanding principal balance on the term loan under the EXCO Resources Credit Agreement ("Term Loan") and the remaining proceeds were used to reduce outstanding indebtedness under the revolving commitment of the EXCO Resources Credit Agreement.

Compass Production Partners

On October 31, 2014, we closed the sale of our entire interest in Compass to HGI for $118.8 million in cash. We used a portion of the proceeds to reduce indebtedness under the EXCO Resources Credit Agreement. Prior to the closing of the sale, we reported our 25.5% interest in Compass using proportional consolidation. Our consolidated assets and liabilities were reduced by our proportionate share of Compass's net assets of $31.4 million which included our proportionate share of Compass's indebtedness of $83.2 million on October 31, 2014. The sale of our interest in Compass did not significantly alter the relationship between our capitalized costs and proved reserves and was accounted for as an adjustment of capitalized costs with no gain or loss recognized in accordance with Rule 4-10(c)(6)(i) of Regulation S-X. As a result, our capitalized costs were further reduced by $87.4 million.

At the closing, EXCO and HGI terminated the existing operating and administrative services agreements and entered into a customary transition services agreement pursuant to which EXCO will provide certain transition services to Compass for up to nine months following the closing date. In addition, following the closing, EXCO will no longer be required to offer acquisition opportunities to Compass or any of its affiliates.

EXCO Resources Credit Agreement amendment

On February 6, 2015, we amended the EXCO Resources Credit Agreement which decreased our borrowing base to $725.0 million as a result of the recent decline in oil and natural gas prices. In addition, the financial covenants were amended to include an interest coverage ratio and senior secured indebtedness to consolidated EBITDAX ratio. The leverage ratio was suspended until the fourth quarter of 2016 and the ratio requirements thereafter were modified. See further discussion of the amendment to the EXCO Resources Credit Agreement as part of "Our liquidity, capital resources and capital commitments" in “Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations”.

Critical accounting estimates

The process of preparing financial statements in conformity with GAAP requires us to make estimates and assumptions to determine reported amounts of certain assets, liabilities, revenues, expenses and related disclosures. 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, derivative financial instruments, business combinations, share-based compensation, oil and natural gas properties, goodwill, revenue recognition, asset retirement obligations and income taxes.

The following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in our application of GAAP. For a more complete discussion of our accounting policies see "Note 2. Summary of significant accounting policies" in the Notes to our Consolidated Financial Statements.

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. The estimates of the fair values of our derivative financial instruments require judgment. The fair value of our derivative financial instruments is determined by quoted futures prices, utilization of the credit-adjusted risk-free rate curves and the implied rates of volatility. 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. 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.

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. Estimating the grant date fair value of our share-based compensation requires management to make assumptions and to apply judgment in estimating the fair value. These assumptions and judgments include estimating the volatility of our share price, dividend yields, expected term, forfeiture rates and other company-specific inputs. Changes in these assumptions could materially affect the estimate of the fair value. If actual results are not consistent with the assumptions used, the share-based compensation expense reported in our financial statements may not be representative of the actual economic impact of the share-based compensation.

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 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. In determining whether such costs should be impaired or transferred, we evaluate lease expiration dates, recent drilling results, future development plans and current market values. 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.

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. Each of the reference prices for oil and natural gas are further adjusted for quality factors and regional differentials to derive estimated future net revenues. The price used for NGL's was based on the trailing 12 month average of realized prices. 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.

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.

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. The discounted cash flow model used in the income approach requires us to make various judgmental assumptions about future production, revenues, operating and capital expenditures, discount rates and other inputs which are based on our budgets, business plans, economic projections and anticipated future cash flows. The market approach requires us to make assumptions regarding the identifications of comparable companies and transactions as well as the future performance of ourselves and the comparable companies. Due to the changing market conditions, it is possible that assumptions used in the model may change in the future, which could materially affect the estimate of the fair value of our business.

Revenue recognition and natural gas imbalances

We use the sales method of accounting for oil and natural gas revenues. We record sales revenue based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement. We estimate our sales volumes primarily on company-measured volume readings. We then adjust our oil, natural gas and NGLs sales in subsequent periods based on the data received from our purchasers that reflects actual volumes and prices received. Historically, these differences have been immaterial. Gas imbalances at December 31, 2014, 2013 and 2012 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. The costs of plugging and abandoning oil and natural gas properties fluctuate with costs associated with the industry. Our calculation of asset retirement obligation uses numerous assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. 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*. 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 must make certain estimates related to the reversal of temporary differences, and actual results could vary from those estimates. We assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. Examples of positive and negative evidence include historical taxable income or losses, forecasted income or losses, the estimated timing of the reversals of existing temporary differences as well as prudent and feasible tax planning strategies. 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. As of December 31, 2014, we continued to have a full valuation allowance against our net deferred tax assets. A significant amount of judgment is also required in determining the amount of unrecognized tax benefit to record for uncertain tax positions. We consider the amounts and probabilities of the outcomes that could be realized upon ultimate settlement of an uncertain tax position using the facts, circumstances and information available at the reporting date to establish the appropriate amount of unrecognized tax benefit. We currently do not have any uncertain tax positions recorded as of December 31, 2014.

Our results of operations

A summary of key financial data for the years ended December 31, 2014, 2013 and 2012 related to our results of operations is presented below:

	Year Ended December 31,			Year to year change	
(dollars in thousands, except per unit prices)	2014	2013	2012	2014-2013	2013-2012
Production:					
Oil (Mbbls)	2,236	1,188	704	1,048	484
Natural gas (Mmcf)	120,980	153,321	182,644	(32,341)	(29,323)
Natural gas liquids (Mbbls)	224	243	510	(19)	(267)
Total production (Mmcfe) (1)	135,740	161,907	189,928	(26,167)	(28,021)
Average daily production (Mmcfe)	372	444	519	(72)	(75)
Revenues before derivative financial instrument activities:					
Oil	$ 196,316	$ 111,440	$ 62,119	$ 84,876	$ 49,321
Natural gas	457,946	514,309	462,422	(56,363)	51,887
Natural gas liquids	6,007	8,560	22,068	(2,553)	(13,508)
Total revenues	$ 660,269	$ 634,309	$ 546,609	$ 25,960	$ 87,700
Oil and natural gas derivative financial instruments:					
Gain (loss) on derivative financial instruments	$ 87,665	$ (320)	$ 66,133	$ 87,985	$ (66,453)
Average sales price (before cash settlements of derivative financial instruments):					
Oil (per Bbl)	$ 87.80	$ 93.80	$ 88.24	$ (6.00)	$ 5.56
Natural gas (per Mcf)	3.79	3.35	2.53	0.44	0.82
Natural gas liquids (per Bbl)	26.82	35.23	43.27	(8.41)	(8.04)
Natural gas equivalent (per Mcfe)	4.86	3.92	2.88	0.94	1.04
Costs and expenses:					
Oil and natural gas operating costs	$ 64,467	$ 61,277	$ 77,127	$ 3,190	$ (15,850)
Production and ad valorem taxes	29,859	21,971	27,483	7,888	(5,512)
Gathering and transportation	101,574	100,645	102,875	929	(2,230)
Depletion	258,266	237,899	288,401	20,367	(50,502)
Depreciation and amortization	5,303	7,876	14,755	(2,573)	(6,879)
General and administrative (2)	65,920	91,878	83,818	(25,958)	8,060
Interest expense, net	94,284	102,589	73,492	(8,305)	29,097
Costs and expenses (per Mcfe):					
Oil and natural gas operating costs	$ 0.47	$ 0.38	$ 0.41	$ 0.09	$ (0.03)
Production and ad valorem taxes	0.22	0.14	0.14	0.08	—
Gathering and transportation	0.75	0.62	0.54	0.13	0.08
Depletion	1.90	1.47	1.52	0.43	(0.05)
Depreciation and amortization	0.04	0.05	0.08	(0.01)	(0.03)
General and administrative	0.49	0.57	0.44	(0.08)	0.13
Interest expense, net	0.69	0.63	0.39	0.06	0.24
Net income (loss)	$ 120,669	$ 22,204	$ (1,393,285)	$ 98,465	$ 1,415,489

(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 $5.0 million, $10.7 million and $8.9 million for the years ended December 31, 2014, 2013 and 2012, respectively.

The following is a discussion of our financial condition and results of operations for the years ended December 31, 2014, 2013 and 2012.

The comparability of our results of operations for 2014, 2013 and 2012 was affected by:

- the acquisitions of the Haynesville and Eagle Ford assets during 2013;
- the formation and subsequent sale of Compass during 2013 and 2014, respectively;
- the sale of our equity interest in TGGT Holdings, LLC ("TGGT") during 2013;
- fluctuations in oil, natural gas and NGL 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 and 2012;
- 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 our capital structure as a result of the Rights Offering and debt financing transactions.

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:

- 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;
- federal regulations generally prohibiting the export of U.S. crude oils;
- federal regulations applicable to the export of, and construction of export facilities for natural gas and NGLs.
- 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.

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

We sell the majority of our natural gas under individually negotiated gas purchase contracts using market sensitive pricing. Our sales contracts vary in length from spot market sales of a single day to term agreements that may extend for a year or more. Our natural gas customers include utilities, natural gas marketing companies and a variety of commercial and industrial end users. The natural gas purchase contracts define the terms and conditions unique to each of these sales. The price received for natural gas sold on the spot market varies daily, reflecting changing market conditions. Some of our natural gas is sold under contracts which provide for sharing in a percentage of proceeds of NGLs extracted by third party plants.

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

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

Presentation of results of operations

Our discussion of production, revenues and direct operating expenses is based on our producing regions and Compass. Compass included conventional non-shale assets in East Texas, North Louisiana and the Permian Basin. Prior to the formation of Compass on February 14, 2013, the operating results of the properties contributed by EXCO were included within the East Texas/North Louisiana and Other regions in our discussion of production, revenues and direct operating expenses. The operating results of Compass represent our proportionate interest from its formation on February 14, 2013 to the closing of the sale of our interest on October 31, 2014. We closed the acquisition of assets in the Eagle Ford shale and formed our South Texas region on July 31, 2013.

Oil and natural gas production, revenues and prices

The following table presents our production, revenue and average sales prices for the years ended December 31, 2014 and 2013:

	Year Ended December 31,								
	2014			2013			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	92,916	$ 371,074	$ 3.99	123,218	$ 417,811	$ 3.39	(30,302)	$ (46,737)	$ 0.60
South Texas	13,713	176,022	12.84	6,197	85,926	13.87	7,516	90,096	(1.03)
Appalachia	21,289	67,794	3.18	22,816	78,424	3.44	(1,527)	(10,630)	(0.26)
Other	364	3,649	10.02	1,139	9,135	8.02	(775)	(5,486)	2.00
Compass	7,458	41,730	5.60	8,537	43,013	5.04	(1,079)	(1,283)	0.56
Total	135,740	$ 660,269	$ 4.86	161,907	$ 634,309	$ 3.92	(26,167)	$ 25,960	$ 0.94

Production for the year ended December 31, 2014 decreased by 26.2 Bcfe, or 16%, as compared with 2013. The decrease in production in the East Texas/North Louisiana region was primarily due to production declines from changes in our drilling program and the initial contribution of properties to Compass in the first quarter of 2013. The production declines were primarily the result of reduced development activities within this region compared to periods prior to 2013. Our drilling activities in the region resulted in 27 wells turned-to-sales in North Louisiana and 8 wells turned-to-sales in East Texas for the year ended December 31, 2014 compared to 51 wells turned-to-sales in North Louisiana for the year ended December 31, 2013. The wells turned-to-sales for the year ended December 31, 2013 primarily consisted of wells drilled during 2012. The increase in production in the South Texas region was primarily the result of more days of production in the current period as the acquisition of these properties occurred on July 31, 2013. Our drilling activities in the Eagle Ford shale resulted in 63 wells turned-to-sales for the year ended December 31, 2014 compared to 26 wells turned-to-sales for the year ended December 31, 2013. The decrease in production of 1.5 Bcfe in the Appalachia region was a result of natural production declines following the suspension of our drilling program during the second half of 2013. The decrease in production in the Other region was primarily the result of the contribution of properties in the Permian Basin to Compass in 2013. The decrease in our proportionate share of Compass's production was due to the sale of our interest in Compass on October 31, 2014.

Oil and natural gas revenues for the year ended December 31, 2014 increased by $26.0 million, or 4%, as compared with 2013. The increase in revenues was primarily the result of the acquisition of Haynesville and Eagle Ford assets in the third quarter of 2013 and an increase in natural gas prices. This was partially offset by the decrease in production compared to the prior year. Our average natural gas sales price increased 13% to $3.79 per Mcf for the year ended December 31, 2014 from $3.35 per Mcf for the year ended December 31, 2013. Our average sales price for natural gas during the year ended December 31, 2014 was positively impacted by higher market prices and was partially offset by the widening of differentials in Appalachia as a result of an oversupply of natural gas in the Northeast region. Our average sales price of oil per Bbl decreased 6% to $87.80 per Bbl for the year ended December 31, 2014 from $93.80 per Bbl for the year ended December 31, 2013. Our average sales price for oil in the South Texas region is most closely correlated to the Louisiana Light Sweet ("LLS") price index. Our average sales price of NGLs per Bbl decreased 24% to $26.82 per Bbl for the year ended December 31, 2014 from $35.23 per Bbl for the year ended December 31, 2013.

The following table and discussion 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
Other	1,139	9,135	8.02	8,996	78,651	8.74	(7,857)	(69,516)	(0.72)
Compass	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 Compass 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 acquisition of Haynesville assets during July 2013. Our drilling activities in East Texas/North Louisiana resulted in 51 wells turned-to-sales for the year ended December 31, 2013 compared to 84 wells turned-to-sales for the year ended December 31, 2012. 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 NGLs 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 Compass. Our proportionate share of Compass'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 Haynesville and Eagle Ford assets, which was partially offset by lower revenues arising from the contribution of properties to Compass and normal production declines. Our average natural gas sales price increased 32% 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. Our average sales price of oil per Bbl increased 6% 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 of NGLs per Bbl decreased 19% to $35.23 per Bbl for the year ended December 31, 2013 from $43.27 per Bbl for the year ended December 31, 2012.

Oil and natural gas operating costs

The following tables and discussion present our oil and natural gas operating costs for the years ended December 31, 2014, 2013, and 2012.

	Year Ended December 31,								
	2014			2013			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	$ 18,056	$ 3,815	$ 21,871	$ 16,980	$ 4,294	$ 21,274	$ 1,076	$ (479)	$ 597
South Texas	15,242	396	15,638	11,454	13	11,467	3,788	383	4,171
Appalachia	14,072	58	14,130	14,073	—	14,073	(1)	58	57
Other	300	—	300	1,623	—	1,623	(1,323)	—	(1,323)
Compass	10,838	1,690	12,528	11,397	1,443	12,840	(559)	247	(312)
Total	$ 58,508	$ 5,959	$ 64,467	$ 55,527	$ 5,750	$ 61,277	$ 2,981	$ 209	$ 3,190

	Year Ended December 31,								
	2014			2013			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	$ 0.19	$ 0.04	$ 0.23	$ 0.14	$ 0.03	$ 0.17	$ 0.05	$ 0.01	$ 0.06
South Texas	1.11	0.03	1.14	1.85	—	1.85	(0.74)	0.03	(0.71)
Appalachia	0.66	—	0.66	0.62	—	0.62	0.04	—	0.04
Other	0.82	—	0.82	1.42	—	1.42	(0.60)	—	(0.60)
Compass	1.45	0.23	1.68	1.34	0.17	1.51	0.11	0.06	0.17
Total	$ 0.43	$ 0.04	$ 0.47	$ 0.34	$ 0.04	$ 0.38	$ 0.09	$ —	$ 0.09

Oil and natural gas operating costs for the year ended December 31, 2014 increased by $3.2 million, or 5%, as compared with 2013. The increase in oil and natural gas operating costs was primarily due to the acquisition of the Eagle Ford assets. This was partially offset by the lower operating costs resulting from the contribution of properties to Compass in the first quarter of 2013 as well as the sale of our interest in Compass on October 31, 2014. We implemented several costs reduction initiatives in the South Texas region in 2014 which resulted in decreased saltwater disposal costs, improved efficiencies and reduced reliance on third-party contractors.

Oil and natural gas operating costs for the year ended December 31, 2014 were $0.47 per Mcfe compared to $0.38 per Mcfe for the year ended December 31, 2013. The net increase in oil and natural gas operating costs per Mcfe is primarily attributable to lower production in relation to certain fixed lease operating expenses. This increase was partially offset by the cost reduction initiatives in the South Texas region, as well as the contribution and the sale of properties to Compass in 2013 and 2014, respectively, which typically have a higher average cost per Mcfe compared to the average for the rest of our properties. As a result of the cost reduction initiatives in the South Texas region, we were able to reduce our costs per Mcfe in the region to $1.14 per Mcfe in 2014 from $1.85 per Mcfe in 2013.

	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)
Other	1,623	—	1,623	12,539	312	12,851	(10,916)	(312)	(11,228)
Compass	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)
Other	1.42	—	1.42	1.39	0.03	1.42	0.03	(0.03)	—
Compass	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 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 Compass. 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 Haynesville and Eagle Ford assets.

Oil and natural gas operating costs for the year ended December 31, 2013 were $0.38 per Mcfe, a decrease of 7% from 2012. The net decrease in oil and natural gas operating costs per Mcfe is attributable to the contribution of properties to Compass, 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.

Gathering and transportation

Gathering and transportation expenses for the year ended December 31, 2014 increased by $0.9 million, or 1%, as compared with 2013. Gathering and transportation expenses were $0.75 per Mcfe for the year ended December 31, 2014, as compared to $0.62 per Mcfe for the year ended December 31, 2013. The increase in gathering and transportation expenses on a per Mcfe basis was primarily due to lower volumes in relation to fixed costs under firm transportation contracts in the East Texas/North Louisiana region. In addition, a marketing arrangement with a significant purchaser of our Haynesville shale production volumes was amended in April 2014 resulting in higher gathering and transportation expenses.

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. The increase in gathering and transportation expense on a per Mcfe basis was due to lower volumes in relation to fixed costs under firm transportation contracts in the East Texas/North Louisiana region.

Production and ad valorem taxes

(in thousands, except per unit rate)	Year Ended December 31, 2014 Production and ad valorem taxes	% of revenue	Taxes $/ Mcfe	2013 Production and ad valorem taxes	% of revenue	Taxes $/ Mcfe	2012 Production and ad valorem taxes	% of revenue	Taxes $/ Mcfe
Producing region:									
East Texas/North Louisiana	$ 10,032	2.7%	$ 0.11	$ 9,287	2.2%	$ 0.08	$ 17,501	4.2%	$ 0.11
South Texas	13,406	7.6%	0.98	4,962	5.8%	0.80	—	—%	—
Appalachia	2,256	3.3%	0.11	2,653	3.4%	0.12	3,013	6.4%	0.19
Other	92	2.5%	0.25	815	8.9%	0.72	6,969	8.9%	0.77
Compass	4,073	9.8%	0.55	4,254	9.9%	0.50	—	—%	—
Total	$ 29,859	4.5%	$ 0.22	$ 21,971	3.5%	$ 0.14	$ 27,483	5.0%	$ 0.14

Production and ad valorem taxes for the year ended December 31, 2014 increased by $7.9 million, or 36%, as compared to 2013. The increase was primarily attributable to higher production and ad valorem taxes associated with oil production in the South Texas region. Additionally, this increase was due to higher severance tax rates in the State of Louisiana and the expiration of severance tax holidays on certain Haynesville shale wells in the East Texas/North Louisiana region. Production and ad valorem taxes for the year ended December 31, 2013 decreased by $5.5 million, or 20%, as compared to the same period in 2012. 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 Compass and lower severance tax rates in the State of Louisiana. These decreases were partially offset by higher production and ad valorem taxes associated with our liquids production in the South Texas region.

Production and ad valorem tax rates per Mcfe were $0.22, $0.14 and $0.14 for 2014, 2013 and 2012, respectively. The rate per Mcfe increased from 2013 to 2014 due to higher production and ad valorem taxes per Mcfe associated with oil production in the South Texas region, higher severance tax rates in the State of Louisiana and the expiration of severance tax holidays on certain Haynesville shale wells in the East Texas/North Louisiana region. The rate per Mcfe was consistent on a consolidated basis for the year ended December 31, 2013 compared 2012 as a result of higher production and ad valorem taxes per Mcfe associated with oil production in the South Texas region that were offset by lower severance tax rates in the State of Louisiana.

In our East Texas/North Louisiana region, 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 from $0.148 per Mcf. In July 2014, the state of Louisiana increased its severance tax rate to $0.163 per Mcf.

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 production sold. As such, our realized severance and ad valorem tax rates may become more sensitive to prices, except for wells that receive holiday exemptions, if any. The Commonwealth of Pennsylvania requires an impact fee to be paid on all unconventional wells spud based on a price tier calculation for a period of 15 years. The Commonwealth of Pennsylvania is currently considering reforms to its tax code which could result in the enactment of a severance tax on the production of oil and natural gas. This severance tax may replace the impact fee and could have an impact on our production taxes in future periods. There is no certainty that this legislation will be passed nor is it possible to quantify the impact at this time.

Depletion, depreciation and amortization

Depletion expense for the year ended December 31, 2014 increased by $20.4 million, or 9%, as compared with 2013 primarily due to the acquisition of assets in the Haynesville and Eagle Ford shale during the third quarter of 2013. On a per Mcfe basis, the depletion rate for the year ended December 31, 2014 was $1.90 per Mcfe, compared with $1.47 per Mcfe in 2013. The increase in the depletion rate was primarily due to the acquisition of assets in the Haynesville and Eagle Ford shale during the third quarter of 2013 which increased our depletable base and higher future development costs associated with the additional proved undeveloped reserves. The oil producing assets in the Eagle Ford shale result in a higher depletion rate when calculated on per Mcfe basis compared to the rest of our 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.

Depreciation and amortization costs for the year ended December 31, 2014 decreased by $2.6 million, or 33%, as compared with the same period in 2013. The decrease was due to the contribution of gathering assets to Compass in the first quarter of 2013 and reduced spending on certain corporate assets. Our depreciation and amortization costs for the year ended December 31, 2013 decreased by $6.9 million, or 47%, compared to 2012. The decrease was due to contribution of gathering assets to Compass and the sale of other corporate assets in 2012.

Accretion of discount on asset retirement obligations for the year ended December 31, 2014 increased by $0.2 million, or 7%, compared with 2013. The increase was primarily due to additional accretion of discount on asset retirement obligations of Haynesville and Eagle Ford assets acquired during the third quarter of 2013 and was partially offset by the contribution and sale of properties to Compass. The decrease for the year ended December 31, 2013 compared to 2012 was the result of the contribution of properties to Compass.

Impairment of oil and natural gas properties

For the year ended December 31, 2014, we did not record an impairment to our oil and natural gas properties. For the years ended December 31, 2013 and 2012, we recorded impairments of our oil and natural gas properties of $108.5 million and $1.3 billion, respectively. The impairments for the year ended December 31, 2013 were primarily due to 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 impairment of our oil and natural gas properties during 2012 was due to the significant decline in natural gas prices. As a result of recent declines in oil and natural gas prices, we expect to incur additional impairments to our oil and natural gas properties during 2015 if prices do not increase.

General and administrative

The following table presents our general and administrative expenses for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,			Year to year change	
(in thousands, except per unit rate)	2014	2013	2012	2014-2013	2013-2012
General and administrative costs:					
Gross general and administrative expense	$ 119,959	$ 147,432	$ 152,057	$ (27,473)	$ (4,625)
Technical services and service agreement charges	(24,747)	(26,846)	(25,242)	2,099	(1,604)
Operator overhead reimbursements	(13,507)	(10,462)	(20,544)	(3,045)	10,082
Capitalized salaries and share-based compensation	(15,785)	(18,246)	(22,453)	2,461	4,207
General and administrative expense	$ 65,920	$ 91,878	$ 83,818	$ (25,958)	$ 8,060

General and administrative expenses for the year ended December 31, 2014 decreased by $26.0 million, or 28%, compared with 2013. Significant components of the changes in general and administrative expense for the year ended December 31, 2014 compared to 2013 were a result of:

- decreased personnel and employee relocation costs of $12.4 million. The decrease was primarily the result of a reduction in our workforce and the centralization of certain functions from the Appalachia region. Also, we incurred $5.0 million of severance costs during 2013 associated with the resignation of our former chairman and chief executive officer. The decrease was partially offset by $2.2 million in severance costs associated with the reduction in our workforce during the second quarter of 2014;
- decreased gross share-based compensation expense of $7.6 million. The decrease was primarily due to a reduction in headcount, higher forfeitures and additional expenses incurred with the modification of share-based payments in connection with the retirement and resignation of former executives in the prior year;

- decreased various other gross general and administrative expenses of $7.5 million. The decrease reflects our efforts to reduce our general and administrative costs such as office expenses, travel and software licenses. We also incurred additional costs for legal and transition services related to the Haynesville and Eagle Ford asset acquisitions in 2013;
- decreased technical services and service agreement recoveries of $2.1 million. The decrease was primarily a result of reduced headcount and increased focus on the development of assets that are not included in joint venture arrangements in which we can recover technical services including our operations in the South Texas region;
- increased operator overhead reimbursements of $3.0 million. The increase is primarily associated with the additional operated wells acquired and developed in the Haynesville and Eagle Ford shales; and
- decreased capitalized salaries and share-based compensation expense of $2.5 million primarily as a result of a reduction in employee headcount.

General and administrative expenses for the year ended December 31, 2013 increased by $8.1 million, or 10%, compared with 2012. 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 during 2013 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 Compass, 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 Compass;
- decreased capitalized salaries and share-based compensation expense 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 and resignation of former executives in the prior year. 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 Haynesville and Eagle Ford assets, as well as higher engineering and technology costs.

We have implemented initiatives to reduce our general and administrative costs during 2015 including a 15% reduction in our workforce. This will reduce our general and administrative expenses in future periods however we will incur severance payments in connection with these actions.

(Gain) loss on divestitures and other operating items

(Gain) loss on divestitures and other operating items was a net loss of $5.3 million, a net gain of $177.5 million and a net loss of $17.0 million for the years ended December 31, 2014, 2013 and 2012, respectively. The net loss for the year ended December 31, 2014 primarily consisted of legal expenses. 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 Compass. Partially offsetting the gain were $3.0 million of transaction costs associated with the acquisition of Haynesville and Eagle Ford assets and $6.7 million of legal expenses. The net loss of $17.0 million for the year ended December 31, 2012 included the retroactive portion of the Pennsylvania impact fee, resolution of various title defect adjustments, legal expenses, and losses related to equipment sales and inventory impairments.

Interest expense, net

The following table presents our interest expense for the years ended December 31, 2014, 2013 and 2012:

(in thousands)	Year Ended December 31, 2014	2013	2012	Period to period change 2014-2013	2013-2012
Interest expense:					
2018 Notes	$ 57,585	$ 57,485	$ 57,394	$ 100	$ 91
2022 Notes	30,104	—	—	30,104	—
EXCO Resources Credit Agreement	16,368	33,119	31,068	(16,751)	2,051
Compass Production Partners Credit Agreement	2,022	2,335	—	(313)	2,335
Amortization of deferred financing costs	7,939	28,169	8,644	(20,230)	19,525
Capitalized interest	(20,060)	(18,729)	(23,809)	(1,331)	5,080
Other	326	210	195	116	15
Total interest expense	$ 94,284	$ 102,589	$ 73,492	$ (8,305)	$ 29,097

Our interest expense, net for the year ended December 31, 2014 decreased $8.3 million from 2013 primarily due to a decrease in the amortization of deferred financing costs and lower average outstanding indebtedness. We incurred $21.0 million in expense related to accelerated deferred financing costs during 2013 primarily as a result of amendments to the EXCO Resources Credit Agreement. This was partially offset by higher average interest rates during 2014 as a result of the issuance of the 2022 Notes.

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 as a result of amendments to the EXCO Resources Credit Agreement. The increase in interest expense, net was also the result of a reduction in capitalized interest related to lower balances of unproved oil and natural gas properties. The increase in our average interest rate under the EXCO Resources Credit Agreement was partially offset by lower average borrowings during 2013 compared to 2012.

Derivative financial instruments

Our oil and natural gas derivative financial instruments resulted in a net gain of $87.7 million, net loss of $0.3 million and a net gain of $66.1 million for the years ended December 31, 2014, 2013 and 2012, respectively. The net gains during 2014 were primarily the result of declines in the futures prices of oil and natural gas towards the end of the year. 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.

Average realized pricing:	Year Ended December 31, 2014	2013	2012	Period to period change 2014-2013	2013-2012
Natural gas equivalent per Mcfe	$ 4.86	$ 3.92	$ 2.88	$ 0.94	$ 1.04
Cash settlements (payments) on derivative financial instruments, per Mcfe	(0.14)	0.26	1.06	(0.40)	(0.80)
Net price per Mcfe, including derivative financial instruments	$ 4.72	$ 4.18	$ 3.94	$ 0.54	$ 0.24

Our total cash settlements for 2014 were payments of $19.0 million, or $0.14 per Mcfe compared to receipts of $42.1 million, or $0.26 per Mcfe, in 2013 and $202.1 million, or $1.06 per Mcfe, in 2012. As noted above, the significant fluctuations between settlements on our derivative financial instruments demonstrate the volatility in commodity prices.

Equity income (loss)

Our equity income (loss) was net income of $0.2 million, a net loss of $53.3 million and net income of $28.6 million for the years ended December 31, 2014, 2013 and 2012, respectively. The increase in equity income for the year ended December 31, 2014 compared with 2013 was primarily due to an impairment of our investment in TGGT during 2013. This was partially offset by equity income from our investment in TGGT prior to the sale of our interest on November 15, 2013.

The decrease in equity income for the year ended December 31, 2013 compared to 2012 was primarily due to the impairment of our investment in TGGT in 2013. Equity losses from our investment in OPCO increased $4.7 million from 2012 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.

Income taxes

The following table presents a reconciliation of our income tax provision (benefit) for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Federal income taxes (benefit) provision at statutory rate of 35%	$ 42,234	$ 7,772	$ (487,649)
Increases (reductions) resulting from:			
Goodwill	—	16,382	—
Adjustments to the valuation allowance	(64,757)	(28,865)	544,949
Non-deductible compensation	3,409	1,328	1,893
State taxes net of federal benefit	3,464	3,239	(59,406)
State tax rate change	15,496	—	—
Other	154	144	213
Total income tax provision	$ —	$ —	$ —

During both 2014 and 2013, both federal and state income taxes were reduced to zero by a corresponding decrease to the valuation allowance previously recognized against net deferred tax assets. The net result was no income tax provision for both 2014 and 2013.

During 2012, our net loss was significantly impacted by the impairments of our proved oil and natural gas properties. The tax benefits arising from these 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.

As of December 31, 2014, 2013, and 2012, there were no unrecognized tax benefits, including interest and penalties, that would be required to be recognized in our financial statements.

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 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 dispositions of oil and natural gas properties or other assets, including our ability to obtain financing in order to fund the acquisition of properties under a participation agreement with a joint venture partner in the Eagle Ford shale;
- reductions to our borrowing base; and

- our ability to maintain compliance with debt covenants.

Recent events affecting liquidity

During 2014, we utilized the proceeds from the Rights Offering and the sale of certain assets in the Permian Basin to reduce indebtedness under the EXCO Resources Credit Agreement by an aggregate amount of $341.1 million. On April 16, 2014, we completed a public offering of $500.0 million in aggregate principal amount of senior unsecured notes due April 15, 2022. We received net proceeds of approximately $490.0 million after offering fees and expenses. We used a portion of the net proceeds to repay the $297.8 million outstanding principal balance on the Term Loan and the remaining proceeds were used to reduce indebtedness under the revolving commitment of the EXCO Resources Credit Agreement.

On October 31, 2014, we closed the sale of our entire interest in Compass for $118.8 million in cash. We used a portion of the proceeds to reduce indebtedness under the EXCO Resources Credit Agreement. Our borrowing base was not affected by this sale as Compass was not a guarantor subsidiary. In addition, we amended the EXCO Resources Credit Agreement to increase our borrowing base to $900.0 million. As a result of these transactions, our liquidity improved from $224.6 million as of December 31, 2013 to $761.2 million as of December 31, 2014.

On February 6, 2015, we amended the EXCO Resources Credit Agreement to decrease our borrowing base from $900.0 million to $725.0 million as a result of the recent decline in oil and natural gas prices. The decrease in our borrowing base would have resulted in liquidity of $586.2 million on a pro forma basis if the borrowing base redetermination would have occurred on December 31, 2014. The next borrowing base redetermination for the EXCO Resources Credit Agreement will occur in August 2015. In addition, the financial covenants were amended to include an interest coverage ratio and senior secured indebtedness to consolidated EBITDAX ratio. The leverage ratio was suspended until the fourth quarter of 2016 and the ratio requirements thereafter were modified.

As a result of the recent decline in commodity prices, we plan to reduce our capital expenditures and defer a significant amount of our development until commodity prices improve. Our 2015 capital budget is expected to exceed our cash flows from operations and the deficit will be funded with borrowings under the EXCO Resources Credit Agreement. We have implemented cost reduction initiatives in order to mitigate the impact on our cash flows and liquidity. This includes the negotiation of development and operating cost reductions with several key vendors and plans to continue to pursue further reductions. Also, we have implemented initiatives to reduce our general and administrative costs including a 15% reduction in our workforce during 2015. We believe this strategy will allow us to preserve our liquidity in order to execute on our development program and corporate strategies.

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. 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. The borrowing base redetermination process considers assumptions related to future commodity prices; therefore, our borrowing capacity could be negatively impacted by further declines in oil and natural gas prices. Accordingly, our ability to effectively execute our corporate strategies and manage our operating, general and administrative expenses and capital expenditure programs 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, 2014:

(in thousands)	December 31, 2014
EXCO Resources Credit Agreement	$ 202,492
2018 Notes (1)	750,000
2022 Notes	500,000
Total debt	$ 1,452,492
Net debt	$ 1,382,217
Borrowing base (2)	$ 900,000
Unused borrowing base (3)	$ 690,935
Cash (4)	$ 70,275
Unused borrowing base plus cash	$ 761,210

(1) Excludes unamortized discount of $6.0 million at December 31, 2014.
(2) On February 6, 2015, our borrowing base was reduced to $725.0 million, which would have resulted in liquidity of $586.2 million on a pro forma basis if the borrowing base redetermination had occurred on December 31, 2014.
(3) Net of $6.6 million in letters of credit as of December 31, 2014.
(4) Includes restricted cash of $24.0 million at December 31, 2014.

Debt covenants

As of December 31, 2014, our consolidated debt consisted of the EXCO Resources Credit Agreement, the 2018 Notes and the 2022 Notes (see "Note 6. Debt" in the Notes to our Consolidated Financial Statements for a further description of each agreement).

As of December 31, 2014, EXCO was in compliance with the financial covenants contained in its credit agreement:

- our consolidated current ratio (as defined in the EXCO Resources Credit Agreement) of 2.5 to 1.0 exceeded the minimum of at least 1.0 to 1.0 as of the end of any fiscal quarter; and
- our ratio of consolidated funded indebtedness to consolidated EBITDAX (as defined in the EXCO Resources Credit Agreement) of 3.9 to 1.0 did not exceed the maximum of 4.5 to 1.0 at the end of any fiscal quarter.

On February 6, 2015, we entered into the fourth amendment to the EXCO Resources Credit Agreement which amended our financial covenants under the agreement. The financial covenants (as defined in the EXCO Resources Credit Agreement) were amended to require that we:

- maintain a consolidated current ratio of at least 1.0 to 1.0 as of the end of any fiscal quarter;
- maintain a ratio of consolidated EBITDAX to consolidated interest expense ("Interest Coverage Ratio") of at least 2.0 to 1.0 as of the end of any fiscal quarter;
- not permit our ratio of senior secured indebtedness to consolidated EBITDAX ("Secured Indebtedness Ratio") to be greater than 2.50 to 1.0 as of the end of any fiscal quarter; and
- not permit our ratio of consolidated funded indebtedness to consolidated EBITDAX ("Leverage Ratio") as of the end of any fiscal quarter to be greater than the ratio set forth for the following periods:

Period	Ratio
The fiscal quarter ending December 31, 2016	6.00 to 1.00
The fiscal quarter ending March 31, 2017 and June 30, 2017	5.75 to 1.00
The fiscal quarter ending September 30, 2017	5.25 to 1.00
The fiscal quarter ending December 31, 2017	4.75 to 1.00
Each fiscal quarter ending thereafter	4.50 to 1.00

The Leverage Ratio will be calculated based on the consolidated EBITDAX for the trailing four quarter period ending on the last day of such fiscal quarter, except, the consolidated EBITDAX for quarter period ending December 31, 2016 shall be consolidated EBITDAX for quarter ending December 31, 2016 multiplied by 4.00, consolidated EBITDAX for the two quarter period ending March 31, 2017 shall be consolidated EBITDAX for such period multiplied by 2.00, and consolidated EBITDAX for the three quarter period ending June 30, 2017 shall be consolidated EBITDAX for such period multiplied by 4/3.

The amendments to the financial covenants will become effective as of March 31, 2015. If these covenants were effective as of December 31, 2014, our Interest Coverage Ratio of 3.6 to 1.0 would have exceeded the minimum of at least 2.0 to 1.0 and our Secured Indebtedness Ratio of 0.6 to 1.0 would not have exceeded the maximum of 2.50 to 1.0.

The indenture governing the 2018 Notes and 2022 Notes contains incurrence covenants which restrict our ability to incur additional indebtedness or pledge assets, among other things.

There are certain risks arising from volatility in oil and/or natural gas prices that could impact our ability to meet debt covenants in future periods. In particular, our Interest Coverage Ratio, Secured Indebtedness Ratio, and Leverage Ratio, each as defined in the EXCO Resources Credit Agreement, are computed using EBITDAX for a trailing period 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 these covenants is negatively impacted when oil and/or natural gas prices and/or production declines over an extended period of time. If we are not able to meet our debt covenants in future periods, 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, 2018 Notes and 2022 Notes could result in an event of default, which could adversely affect our business, financial condition and results of operations. See "Note 6. Debt" in the Notes to our Consolidated Financial Statements for a description of our covenants under the EXCO Resources Credit Agreement, 2018 Notes and 2022 Notes.

Capital commitments

During 2013, we entered into the Participation Agreement with a joint venture partner in the Eagle Ford shale to mitigate the impact of development expenditures on our capital resources and liquidity. EXCO is required to offer to purchase our joint venture partner's working interest in wells drilled that have been on production for at least one year. These offers will be made on a quarterly basis for groups of wells based on a price defined in the Participation Agreement, subject to specific well criteria and return hurdles. The wells included in the offer process that meet all of the specific well criteria are deemed to be "Committed Wells" and wells that do not meet the criteria are deemed to be "Uncertainty Wells." The specific well criteria includes factors such as the amount of time on artificial lift, temporary shut-in time, interference from other wells, recent offset fracturing activities or other trends that may result in variability in the performance trends used to establish estimates of reserves. Our joint venture partner is required to accept our offer on Committed Wells if they meet the established return thresholds. If a group of Committed Wells does not meet the established return thresholds, our joint venture partner has the right to decline our offer and the wells can be included in future offers. Our joint venture partner may accept the offers for the Uncertainty Wells; however, they have the ability to elect to defer those wells to future periods when they meet all of the criteria. Any well included in the offer process that remains an Uncertainty Well for two consecutive quarters becomes a Committed Well in the next quarterly offer process. Our joint venture partner has a right to retain an undivided 15% of their collective interest in the wells that we acquire.

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 our joint venture partner 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 our joint venture partner’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. Our joint venture partner is required to accept the offer if it exceeds the required return. If the PV-10 value exceeds our joint venture partner’s required return on investment, then EXCO and our joint venture partner 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.

These acquisitions are expected to increase the borrowing base under the revolving commitment of the EXCO Resources Credit Agreement and are expected to be funded with borrowings under the EXCO Resources Credit Agreement, cash flows from operations, or other financing arrangements. Our joint venture partner has the right to participate in certain wells drilled in the Eagle Ford shale outside of the core area, as defined under the Participation Agreement, however these wells are not included as part of the acquisition program. If our joint venture partner elects to participate in certain wells outside of our core area, we will share equally in the working interest of the well.

As of December 31, 2014, we had spud 86 wells and turned-to-sales 60 wells which are expected to be included within future offers under the Participation Agreement. During 2015, we expect to spud an additional 16 wells which will be included in future offers under the Participation Agreement. The timing of these offers and potential acquisitions is dependent upon the date these wells are turned-to-sales, downtime during the year preceding the offer process and other factors. Prior to the acquisitions in future periods, our average working interest in wells developed under this agreement is approximately 17% and our joint venture partner's average working interest is approximately 50%. The remaining working interest is held by other third-party owners and is not part of the acquisition program.

Our average drilling and completion costs for wells that have been turned-to-sales in the joint venture area are $7.4 million per well, of which our joint venture partner's share is approximately $3.8 million per well and our share prior to the acquisition is $1.3 million per well. Our estimated average drilling and completion costs for wells that have been recently spud in the joint venture area are estimated to be $7.1 million per well, of which our joint venture partner's share is approximately $3.6 million per well and our share prior to the acquisition is $1.2 million per well.

We made our first offer for wells drilled under the Participation Agreement during the first quarter of 2015. This included 7 wells for a total offer price of approximately $15.0 million. The offer consisted of 1 Committed Well for approximately $3.0 million and 6 Uncertainty Wells for approximately $12.0 million. Therefore, our joint venture partner is only required to accept the offer for the Committed Well. Our joint venture partner may accept the offers for the Uncertainty Wells, however they have the ability to elect to defer those wells to future periods when they meet all of the criteria. We expect the offer and acceptance process to be completed and the acquisition to close during the first quarter of 2015. There are 34 additional wells that are expected to be included in the offer process during the remainder of 2015; however, the extent and timing of these acquisitions in future periods will be dependent on the terms and conditions of the offer process. If our offers for the wells included in the first four quarters of the offer process do not meet the established return thresholds, we must increase our offer to meet the thresholds or our joint venture partner will no longer be required to accept future offers for Committed Wells that meet the established return thresholds. If we do not meet this requirement, this could prevent us from acquiring additional working interests in properties from our joint venture partner under the Participation Agreement if they do not accept our offers in the future.

Historical sources and uses of funds

Our primary sources of cash in 2014 were cash flows from operations, proceeds received from the Rights Offering and the sale of non-core assets. As a result of these sources of cash, we were able to significantly reduce our outstanding indebtedness under the EXCO Resources Credit Agreement.

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

	Year Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Net cash provided by operating activities	$ 362,093	$ 350,634	$ 514,786
Net cash used in investing activities	(221,588)	(252,478)	(427,094)
Net cash used in financing activities	(144,683)	(93,317)	(74,045)
Net increase (decrease) in cash	$ (4,178)	$ 4,839	$ 13,647

Operating activities

The primary factors impacting our cash flows from operating activities generally include: (i) levels of production from our oil and natural gas properties, (ii) prices we receive from the sales of oil, natural gas and NGLs 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.

For the year ended December 31, 2014, our net cash provided by operating activities was $362.1 million as compared to $350.6 million for the year ended December 31, 2013. The increase is primarily attributable to higher revenues from the Haynesville and Eagle Ford shale assets we acquired in 2013 as well as an increase in natural gas prices. This was partially offset by lower natural gas production as well as a decrease in oil prices. In addition, the increase was due to changes in accounts receivable which provided cash of $52.0 million for the year ended December 31, 2014 as compared to $46.2 million of cash used for the year ended December 31, 2013. The decrease in accounts receivable for the year end December 31, 2014 as compared to prior year was primarily due to timing of collections of our oil and natural gas sales. This was partially offset by cash payments of $19.0 million on derivative contracts for the year ended December 31, 2014 compared to cash receipts of $42.1 million in the prior year.

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 Haynesville and Eagle Ford assets and higher realized oil and natural gas prices were partially offset by lower production primarily due to our contribution of properties to Compass.

Investing activities

Our investing activities consist primarily of drilling and development expenditures, acquisitions and divestitures. Future acquisitions are dependent on oil and natural gas prices, availability of producing properties and attractive acreage, acceptable rates of return, availability of borrowing capacity under the EXCO Resources Credit Agreement and availability of other sources of capital.

For the year ended December 31, 2014, our net cash used in investing activities was $221.6 million which consisted of $391.8 million of drilling and development activities focused on the Haynesville, Bossier and Eagle Ford shales. This was partially offset by $118.8 million of proceeds received from the sale of our interest in Compass and approximately $68.2 million of proceeds received from the sale of our interest in certain non-operated assets in the Permian Basin.

For the year ended December 31, 2013, our cash flows used in investing activities were $252.5 million. Our property acquisitions during 2013 were primarily attributable to the acquisition of Haynesville and Eagle Ford assets of $942.9 million and our proportionate share of Compass'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 Compass, the sale of our equity investment in TGGT of $236.6 million, net of commissions and fees, the sale of undeveloped acreage in the Eagle Ford 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 primarily related to development and exploration activities in the Haynesville and Marcellus shales.

Financing activities

For the year ended December 31, 2014, our net cash used in financing activities was $144.7 million primarily due to $859.9 million in net payments of outstanding indebtedness under the EXCO Resources Credit Agreement, $41.1 million of dividend payments and $10.3 million of deferred financing costs primarily related to issuance of the 2022 Notes. This was offset by $500.0 million of gross proceeds received from issuance of the 2022 Notes and approximately $272.9 million of gross proceeds received from the Rights Offering.

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 net borrowings under the EXCO Resources Credit Agreement to fund the acquisition of the Haynesville and Eagle Ford assets and the additional borrowings of Compass to fund the acquisition of shallow Cotton Valley assets. In addition, we paid $33.6 million of deferred financing costs associated with amendments to the EXCO Resources Credit Agreement and we paid $43.2 million of dividends on our common shares 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 shares during 2012.

Capital expenditures

During 2014, our capital expenditures, including oil and natural gas property acquisitions, totaled $434.8 million, of which $356.3 million was related to drilling and development activities. Our development program during 2014 primarily focused on our properties in the Haynesville, Bossier and Eagle Ford shales. During 2014, we operated three to six operated drilling rigs in the Haynesville and Bossier shales focused on our core area in DeSoto Parish, Louisiana and the Shelby area of East Texas. Our capital expenditures in this region also included re-fracture stimulation treatments on 5 gross (2.8 net) mature Haynesville shale wells. Our development program in the Eagle Ford shale focused on our core area in Zavala County, Texas and limited drilling outside our core area as part of a farmout agreement. We operated two to five operated drilling rigs in this region during 2014. We also installed pumping units on 87 gross (45.6 net) wells in the region to optimize our production. Our development activities during the year featured enhanced drilling and completion techniques which improved our well performance while we efficiently managed our 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 a Participation Agreement with a joint venture partner 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 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 Compass during 2013. Our lease purchases during 2012 were primarily in the Permian Basin on acreage with horizontal drilling potential.

The following table presents our capital expenditures for the years ended December 31, 2014, 2013 and 2012.

	Year Ended December 31,		
(in thousands)	2014	2013	2012
Capital expenditures:			
Lease purchases and seismic	$ 10,477	$ 25,052	$ 49,158
Development capital expenditures	356,344	265,120	403,342
Field operations, gathering and water pipelines	20,256	12,379	1,044
Corporate and other	37,198	37,287	48,303
Total capital expenditures excluding oil and natural gas property acquisitions	424,275	339,838	501,847
Oil and natural gas property acquisitions (1)	10,562	942,946	3,349
Total capital expenditures including oil and natural gas property acquisitions	$ 434,837	$ 1,282,784	$ 505,196

(1) The oil and natural gas property acquisitions of $942.9 million during 2013 included the Eagle Ford and Haynesville assets. 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 a joint venture partner.

2015 capital budget

Our board of directors approved a capital budget of up to $275.0 million for 2015, of which $215.0 million is allocated to development and completion activities. Our development activities in the East Texas/North Louisiana region are primarily focused on the Shelby area in East Texas and a limited drilling and completion program in the Holly area in North Louisiana. This includes a limited amount of capital allocated towards our re-fracture stimulation program. We have reduced our drilling activity in South Texas in response to lower crude oil prices. Our development activities in this region are designed to preserve leasehold commitments, fulfill continuous drilling obligations and drill key test wells in the Buda formation. Our capital expenditures in these regions are directed towards areas which have recently yielded strong results from enhanced drilling and completion methods. This has improved the economics of developing these locations and provides attractive returns even in a low commodity price environment. We also have plans for a limited appraisal drilling program in the Marcellus shale. We believe the capital budget is appropriate for current commodity prices and our capital structure. The 2015 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	25	11.9	17.6	$ 150.0	$ 8.0	$ 158.0
South Texas	23	7.1	10.7	59.0	7.0	66.0
Appalachia	2	0.7	0.5	6.0	8.0	14.0
Corporate and other (2)	—	—	—	—	37.0	37.0
Total	50	19.7	28.8	$ 215.0	$ 60.0	$ 275.0

(1) The wells spud and completed within this table only include those operated by EXCO.
(2) Includes $21.0 million of capitalized interest and $16.0 million of capitalized general and administrative expenses.

The 2015 capital budget excludes our acquisition program with a joint venture partner in the Eagle Ford shale, which is expected to be funded with borrowings under the EXCO Resources Credit Agreement.

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, three-way collars and call option contracts. As of December 31, 2014, 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:				
2015	42,888	$ 4.20	1,095	$ 91.09
Basis swaps:				
2015	—	—	91	6.10
Call options:				
2015	20,075	4.29	365	100.00
Three-way collars:				
2015	27,375		—	
Sold call		4.47		—
Purchased put		3.83		—
Sold put		3.33		—
2016	10,980		—	
Sold call		4.80		—
Purchased put		3.90		—
Sold put		3.40		—

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, 2014, 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, 2014. Gathering and firm transportation services presented in the following table represent our gross commitments under these contracts and a portion of these costs will be incurred by working interest and other owners. The commitments do not include those of our equity method investments.

	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)	$ —	$ —	$ 202,492	$ —	$ 202,492
Senior Notes (2)	—	—	750,000	500,000	1,250,000
Gathering and firm transportation services (3)	136,040	266,289	218,200	101,618	722,147
Other fixed commitments (4)	17,332	18,696	5,613	3,530	45,171
Drilling contracts (5)	22,191	2,538	—	—	24,729
Operating leases and other	5,912	9,070	6,145	1,623	22,750
Total contractual obligations	$ 181,475	$ 296,593	$ 1,182,450	$ 606,771	$ 2,267,289

(1) The EXCO Resources Credit Agreement matures on July 31, 2018. 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.
(2) The 2018 Notes are due on September 15, 2018. The annual interest obligation is $56.3 million. The 2022 Notes are due on April 15, 2022. The annual interest obligation is $42.5 million.
(3) Gathering and firm transportation services reflect contracts whereby EXCO commits to transport a minimum quantity of natural gas on a gatherer's system or a shippers' pipeline. Whether or not EXCO delivers the minimum quantity, we pay the fees as if the quantities were delivered. These expenses represent our gross commitments under these contracts and a portion of these costs will be incurred by working interest and other owners.
(4) Other fixed commitments are primarily related to completion service contracts and minimum sales commitments under marketing contracts.
(5) Drilling contracts represent the early termination fees we would incur if we terminated our contracts for drilling rigs at December 31, 2014. The actual drilling costs under these contracts will be incurred by working interest owners in the development of the related properties.

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 losses 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, 2014, 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 $94.1 million for our oil and natural gas swap contracts. 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, 2014, our exposure to interest rate changes related primarily to borrowings under the EXCO Resources Credit Agreement. The interest rate on the 2018 Notes is fixed at 7.5% per annum and the interest rate on the 2022 Notes is fixed at 8.5% per annum. Interest is payable on borrowings under the EXCO Resources Credit Agreement based on a floating rate as more fully described in "Note 6. Debt" in the Notes to our Consolidated Financial Statements. At December 31, 2014, we had approximately $202.5 million in outstanding borrowings under the EXCO Resources Credit Agreement. A 1% increase in interest rates (100 bps) based on the variable borrowings as of December 31, 2014 would result in an increase in our interest expense of approximately $2.0 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.

Index to Consolidated Financial Statements

Contents

Management's Report on Internal Control Over Financial Reporting

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

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended). Our internal control over financial reporting is designed to provide reasonable assurance to management and our board of directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2014. 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 (2013)*. Based on management's assessment, management believes that, as of December 31, 2014, 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, 2014 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/ Richard A. Burnett
Title:	President and Chief Operating Officer	Title:	Vice President, Chief Financial Officer and Chief Accounting Officer

Dallas, Texas
February 25, 2015

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of EXCO Resources, Inc. and subsidiaries as of December 31, 2014 and 2013, 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, 2014. We also have audited EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* 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, 2014 and 2013, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2014, 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, 2014, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Dallas, Texas
February 25, 2015

EXCO RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(in thousands)	December 31, 2014	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$ 46,305	$ 50,483
Restricted cash	23,970	20,570
Accounts receivable, net:		
Oil and natural gas	81,720	128,352
Joint interest	65,398	70,759
Other	8,945	18,022
Derivative financial instruments	97,278	8,226
Inventory and other	7,150	9,442
Total current assets	330,766	305,854
Equity investments	55,985	57,562
Oil and natural gas properties (full cost accounting method):		
Unproved oil and natural gas properties and development costs not being amortized	276,025	425,307
Proved developed and undeveloped oil and natural gas properties	3,852,073	3,554,210
Accumulated depletion	(2,414,461)	(2,183,464)
Oil and natural gas properties, net	1,713,637	1,796,053
Gathering assets	1,488	33,473
Accumulated depreciation and amortization	(168)	(10,338)
Gathering assets, net	1,320	23,135
Office, field and other assets, net	23,324	27,233
Deferred financing costs, net	30,636	28,807
Derivative financial instruments	2,138	6,829
Deferred income taxes	35,935	—
Goodwill	163,155	163,155
Total assets	$ 2,356,896	$ 2,408,628

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share and share data)	December 31, 2014	December 31, 2013
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 110,211	$ 109,217
Revenues and royalties payable	152,651	154,862
Drilling advances	37,648	22,971
Accrued interest payable	26,265	18,144
Current portion of asset retirement obligations	1,769	191
Income taxes payable	—	—
Deferred income taxes	35,935	—
Derivative financial instruments	892	11,919
Current maturities of long-term debt	—	31,866
Total current liabilities	365,371	349,170
Long-term debt	1,446,535	1,858,912
Derivative financial instruments	—	9,671
Asset retirement obligations and other long-term liabilities	34,986	42,970
Commitments and contingencies	—	—
Shareholders' equity:		
Common shares, $0.001 par value; 350,000,000 authorized shares; 274,351,756 shares issued and 273,773,714 shares outstanding at December 31, 2014; 218,783,540 shares issued and 218,244,319 shares outstanding at December 31, 2013	270	215
Subscription rights, $0.001 par value, none issued and outstanding at December 31, 2014; 54,574,734 issued and outstanding at December 31, 2013	—	55
Additional paid-in capital	3,502,209	3,219,748
Accumulated deficit	(2,984,860)	(3,064,634)
Treasury shares, at cost; 578,042 at December 31, 2014 and 539,221 at December 31, 2013	(7,615)	(7,479)
Total shareholders' equity	510,004	147,905
Total liabilities and shareholders' equity	$ 2,356,896	$ 2,408,628

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share data)	Year Ended December 31, 2014	2013	2012
Revenues:			
Oil	$ 196,316	$ 111,440	$ 62,119
Natural gas	457,946	514,309	462,422
Natural gas liquids	6,007	8,560	22,068
Total revenues	660,269	634,309	546,609
Costs and expenses:			
Oil and natural gas operating costs	64,467	61,277	77,127
Production and ad valorem taxes	29,859	21,971	27,483
Gathering and transportation	101,574	100,645	102,875
Depletion, depreciation and amortization	263,569	245,775	303,156
Impairment of oil and natural gas properties	—	108,546	1,346,749
Accretion of discount on asset retirement obligations	2,690	2,514	3,887
General and administrative	65,920	91,878	83,818
(Gain) loss on divestitures and other operating items	5,315	(177,518)	17,029
Total costs and expenses	533,394	455,088	1,962,124
Operating income (loss)	126,875	179,221	(1,415,515)
Other income (expense):			
Interest expense, net	(94,284)	(102,589)	(73,492)
Gain (loss) on derivative financial instruments	87,665	(320)	66,133
Other income (expense)	241	(828)	969
Equity income (loss)	172	(53,280)	28,620
Total other income (expense)	(6,206)	(157,017)	22,230
Income (loss) before income taxes	120,669	22,204	(1,393,285)
Income tax expense	—	—	—
Net income (loss)	$ 120,669	$ 22,204	$ (1,393,285)
Earnings (loss) per common share:			
Basic:			
Net income (loss)	$ 0.45	$ 0.10	$ (6.50)
Weighted average common shares outstanding	268,258	215,011	214,321
Diluted:			
Net income (loss)	$ 0.45	$ 0.10	$ (6.50)
Weighted average common shares and common share equivalents outstanding	268,376	230,912	214,321

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Operating Activities:			
Net income (loss)	$ 120,669	$ 22,204	$ (1,393,285)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	263,569	245,775	303,156
Share-based compensation expense	4,962	10,748	8,926
Accretion of discount on asset retirement obligations	2,690	2,514	3,887
Impairment of oil and natural gas properties	—	108,546	1,346,749
(Income) loss from equity investments	(172)	53,280	(28,620)
(Gain) loss on derivative financial instruments	(87,665)	320	(66,133)
Cash settlements (payments) of derivative financial instruments	(18,991)	42,119	202,078
Amortization of deferred financing costs and discount on debt issuance	12,055	29,624	9,788
(Gain) loss on divestitures and other non-operating items	(17)	(185,163)	1,303
Effect of changes in:			
Accounts receivable	52,007	(46,176)	112,919
Other current assets	(2,609)	9,627	7,090
Accounts payable and other current liabilities	15,595	57,216	6,928
Net cash provided by operating activities	362,093	350,634	514,786
Investing Activities:			
Additions to oil and natural gas properties, gathering assets and equipment	(391,776)	(320,538)	(534,175)
Property acquisitions	(10,790)	(976,714)	(2,748)
Proceeds from disposition of property and equipment	187,655	749,628	38,045
Restricted cash	(3,400)	49,515	85,840
Net changes in advances to joint ventures	(5,026)	10,645	851
Equity method investments	1,749	236,289	(14,907)
Other	—	(1,303)	—
Net cash used in investing activities	(221,588)	(252,478)	(427,094)
Financing Activities:			
Borrowings under credit agreements	100,000	1,004,523	53,000
Repayments under credit agreements	(964,970)	(1,022,785)	(93,000)
Proceeds received from issuance of 2022 Notes	500,000	—	—
Proceeds from issuance of common shares, net	271,773	1,712	1,968
Payment of common share dividends	(41,060)	(43,214)	(34,358)
Deferred financing costs and other	(10,290)	(33,553)	(1,655)
Payments of common shares repurchased	(136)	—	—
Net cash used in financing activities	(144,683)	(93,317)	(74,045)
Net increase (decrease) in cash	(4,178)	4,839	13,647
Cash at beginning of period	50,483	45,644	31,997
Cash at end of period	$ 46,305	$ 50,483	$ 45,644
Supplemental Cash Flow Information:			
Cash interest payments	$ 91,735	$ 88,936	$ 86,298
Income tax payments	—	—	—
Supplemental non-cash investing and financing activities:			
Capitalized share-based compensation	$ 5,498	$ 7,288	$ 7,513
Capitalized interest	20,060	18,729	23,809
Issuance of common shares for director services	235	93	597
Debt eliminated upon sale of Compass and assumed upon formation of Compass, net for the years ended December 31, 2014 and 2013, respectively	(83,246)	58,613	—
Issuance of subscription rights	—	55	—

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(in thousands)	Common Shares: Shares	Common Shares: Amount	Subscription Rights: Shares	Subscription Rights: Amount	Treasury Shares: Shares	Treasury Shares: Amount	Additional paid-in capital	Accumulated deficit	Total shareholders' equity
Balance at December 31, 2011	217,245	$ 215	—	$ —	(539)	$ (7,479)	$ 3,181,063	$ (1,615,467)	$ 1,558,332
Issuance of common shares	266	—	—	—	—	—	2,565	—	2,565
Share-based compensation	—	—	—	—	—	—	16,439	—	16,439
Restricted shares issued, net of cancellations	615	—	—	—	—	—	—	—	—
Common share dividends	—	—	—	—	—	—	—	(34,658)	(34,658)
Net income	—	—	—	—	—	—	—	(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 shares	228	—	—	—	—	—	1,805	—	1,805
Share-based compensation	—	—	—	—	—	—	17,931	—	17,931
Restricted shares issued, net of cancellations	429	—	—	—	—	—	—	—	—
Common share 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
Issuance of common shares	54,582	55	(54,575)	(55)	—	—	272,008	—	272,008
Share-based compensation	—	—	—	—	—	—	10,453	—	10,453
Restricted shares issued, net of cancellations	987	—	—	—	—	—	—	—	—
Common share dividends	—	—	—	—	—	—	—	(40,895)	(40,895)
Treasury share repurchases	—	—	—	—	(39)	(136)	—	—	(136)
Net income	—	—	—	—	—	—	—	120,669	120,669
Balance at December 31, 2014	274,352	$ 270	—	$ —	(578)	$ (7,615)	$ 3,502,209	$ (2,984,860)	$ 510,004

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 exploration, exploitation, 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. The following is a brief discussion of our producing regions.

- ***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 and Bossier shale assets in East Texas and North Louisiana. BG Group's right to participate in our acquisition of oil and natural gas properties within an area of mutual interest in the East Texas/North Louisiana region expired in August 2014. 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 certain assets in the Eagle Ford shale. The South Texas region also includes assets outside of the joint venture in the Eagle Ford shale, Buda and other 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 conventional assets and Marcellus shale assets 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 held by a jointly owned operating entity ("OPCO") that operates the Appalachia JV's properties. We own a 50% interest in OPCO.

The accompanying Consolidated Balance Sheets as of December 31, 2014 and 2013, Consolidated Statements of Operations, Consolidated Statements of Cash Flows and Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2014, 2013 and 2012 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"). Certain reclassifications have been made to prior period information to conform to current period presentation.

2. Summary of significant accounting policies

Principles of consolidation

We consolidate all of our subsidiaries in the accompanying Consolidated Balance Sheets as of December 31, 2014 and 2013 and the Consolidated Statements of Operations, Consolidated Statements of Cash Flows and Changes in Shareholders' Equity for the years ended December 31, 2014, 2013 and 2012. 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.

We report our interests in oil and natural gas properties using the proportional consolidation method of accounting. We reported our 25.5% interest in Compass Production Partners, L.P. ("Compass") using proportional consolidation for the period from its formation on February 14, 2013 to the sale of our interests on October 31, 2014. See further discussion in "Note 3. Acquisitions, divestitures and other significant events."

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 East Texas/North Louisiana. Funds held in this escrow account are restricted and can be used primarily for drilling and operations in East Texas/North Louisiana.

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, 2014 and 2013. 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, 2014, 2013 and 2012, sales to BG Energy Merchants LLC accounted for approximately 34%, 48% and 36%, respectively, of total consolidated revenues. BG Energy Merchants LLC is a subsidiary of BG Group. For the years ended December 31, 2014 and 2013, Chesapeake Energy Marketing Inc. accounted for approximately 31% and 14%, respectively, of total consolidated revenues. Chesapeake Energy Marketing Inc. is a subsidiary of Chesapeake Energy Corporation ("Chesapeake").

Derivative financial instruments

We use derivative financial instruments to mitigate the impacts of commodity price fluctuations, protect our returns on investments and 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. Our derivative financial instruments are not held for trading purposes.

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 $276.0 million and $425.3 million as of December 31, 2014 and 2013, 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 did not record an impairment of undeveloped properties during 2014 and recorded impairments of $1.0 million and $60.8 million of undeveloped properties during 2013 and 2012, respectively. These impairments were transferred to the depletable portion of the full cost pool during each year. The impairments were recorded to reflect the estimated market price which included certain properties that were no longer part of our drilling plans.

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, 2014, the trailing 12 month reference prices were $4.35 per Mmbtu for natural gas at Henry Hub ("HH"), and $94.99 per Bbl of oil for West Texas Intermediate ("WTI") at Cushing, Oklahoma. Each of the reference prices for oil and natural gas are further adjusted for quality factors and regional differentials to derive estimated future net revenues. The price used for NGLs was $33.03 per Bbl and was based on the trailing 12 month average of realized prices. 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. The ceiling test limitation exceeded the book value of the full cost pool as of December 31, 2014.

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 year ended December 31, 2014, we did not recognize an impairment to our proved oil and natural gas properties and for the years ended December 31, 2013 and 2012 we recognized impairments $108.5 million and $1.3 billion, respectively, to our proved oil and natural gas properties. The impairments for the year ended December 31, 2013 were primarily due to 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 impairment of our oil and natural gas properties during 2012 was due to the significant decline in natural gas prices.

As a result of recent decline in oil and natural gas prices, we expect to incur additional impairments to our oil and natural gas properties in 2015 if prices do not increase. Based on the commodity prices to date during 2015, we expect the reference prices to be utilized in the ceiling test calculation beginning in the first quarter of 2015 to be significantly lower than the price used at December 31, 2014.

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 value. 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. We also consider our market capitalization in our evaluation of the fair value of our business. As a result of testing, the fair value of our business exceeded the carrying value of net assets by approximately 18% at December 31, 2014 and we did not record an impairment charge for the periods ending December 31, 2014, 2013 and 2012.

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:

(in thousands)	December 31, 2014	2013	2012
Asset retirement obligations at beginning of period	$ 42,954	$ 61,864	$ 58,088
Activity during the period:			
Liabilities incurred during the period	576	514	971
Revisions in estimated assumptions	—	1,268	—
Liabilities settled during the period	(33)	(187)	(338)
Adjustment to liability due to acquisitions	107	5,566	—
Adjustment to liability due to divestitures (1)	(9,539)	(28,585)	(744)
Accretion of discount	2,690	2,514	3,887
Asset retirement obligations at end of period	36,755	42,954	61,864
Less current portion	1,769	191	1,200
Long-term portion	$ 34,986	$ 42,763	$ 60,664

(1) For the year ended December 31, 2014, the adjustment to liability due to divestitures consisted primarily of $9.4 million from the sale of our interest in Compass. For the year ended December 31, 2013, the adjustment to liability due to divestitures consisted primarily of $28.3 million from the contribution of our certain conventional assets to Compass.

Our asset retirement obligations are determined using discounted cash flow methodologies based on inputs and assumptions developed by management. 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, 2014, 2013 and 2012 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 $101.6 million, $100.6 million and $102.9 million for the years ended December 31, 2014, 2013 and 2012, 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, 2014, 2013 and 2012, we capitalized $15.8 million, $18.2 million and $22.5 million, respectively. The capitalized amounts include $5.5 million, $7.3 million and $7.5 million of share-based compensation for the years ended December 31, 2014, 2013 and 2012, respectively.

Overhead reimbursement fees

We have classified fees from overhead charges billed to working interest owners of $13.5 million, $10.5 million and $20.5 million for the years ended December 31, 2014, 2013 and 2012, respectively, as a reduction of general and administrative expenses in the accompanying Consolidated Statements of Operations. We classified our share of these charges as oil and natural gas production costs in the amount of $6.4 million, $5.8 million and $10.3 million for the years ended December 31, 2014, 2013 and 2012, respectively.

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 certain properties in the East Texas/North Louisiana JV and the Appalachia JV. In connection with the formation of Compass, we entered into an agreement to perform certain operational, managerial, and administrative services. Compass reimbursed us for costs incurred in connection with the performance of these services based on an agreed upon service fee. As a result of the Compass sale, this agreement was terminated on October 31, 2014 and we entered into a customary transition services agreement pursuant to which EXCO will provide certain transition services to Compass for up to nine months following the closing date. For the years ended December 31, 2014, 2013 and 2012, general and administrative expenses were reduced by $24.7 million, $26.8 million and $25.2 million, respectively, for recoveries of fees for our personnel and services provided to our joint ventures and other partners. 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 stock options, restricted share units and restricted share awards. Diluted EPS is computed in the same manner as basic EPS after assuming the issuance of common shares for all potentially dilutive common share equivalents, which include stock options, restricted share units and restricted share awards, whether exercisable or not. Our diluted EPS for the year ended December 31, 2013 also included subscription rights which were the result of the rights offering of our common shares as discussed in "Note 15. Rights Offering and other equity transactions".

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, restricted share units and restricted share awards, 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, restricted share unit or restricted share award. We capitalize part of our share-based compensation that is attributable to our acquisition, exploration, exploitation and development activities.

Our 2005 Amended and Restated Long-Term Incentive Plan ("2005 Incentive Plan") provides for the granting of options and other equity incentive awards of our common shares 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, restricted share units and restricted share awards, although the plan allows for other share-based awards.

Recent accounting pronouncements

In April 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No.

2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* ("ASU 2014-08"). ASU 2014-08 revises the definition of discontinued operations by limiting discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have (or will have) a major effect on an entity's operations and financial results, removing the lack of continuing involvement criteria and requiring discontinued operations reporting for the disposal of an equity method investment that meets the definition of discontinued operations. ASU 2014-08 also requires expanded disclosures for discontinued operations, including disclosure of pretax profit or loss of an individually significant component of an entity that does not qualify for discontinued operations reporting. ASU 2014-08 retained the scope exception for oil and natural gas properties accounted for under the full-cost method and therefore we do not believe the update will have a significant impact on our consolidated financial condition and results of operations. ASU 2014-08 is effective prospectively to all periods beginning after December 15, 2014. We will apply the guidance prospectively to disposal activity, when applicable, occurring after the effective date of ASU 2014-08.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"). The FASB and the International Accounting Standards Board ("IASB") jointly issued this comprehensive new revenue recognition standard that will supersede nearly all existing revenue recognition guidance under GAAP. The core principle of the guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. In doing so, companies will need to use more judgment and make more estimates than under currently applicable guidance, including identifying performance obligations in the contract, estimating the amount of variable consideration to include in the transaction price and allocating the transaction price to each separate performance obligation. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2016 and permits the use of either the retrospective or cumulative effect transition method. We are currently assessing the potential impact of ASU 2014-09 on our consolidated financial condition and results of operations.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40): *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* ("ASU 2014-15"). ASU 2014-15 provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and sets rules for how this information should be disclosed in the financial statements. ASU 2014-15 is effective for annual periods ending after December 15, 2016 and interim periods thereafter. Early adoption is permitted. As discussed in "Note 6. Debt", our ability to maintain compliance with certain debt covenants might be negatively impacted when oil and/or natural gas prices and production declines over an extended period of time. If such event occurs in future periods that could affect our ability to continue as going concern, we will provide appropriate disclosures as required by ASU 2014-15.

3. Acquisitions, divestitures and other significant events

2014 divestitures

Permian Basin transaction

On March 24, 2014, we closed a purchase and sale agreement with a private party for the sale of our interest in certain non-operated assets in the Permian Basin including producing wells and undeveloped acreage for approximately $68.2 million, after final purchase price adjustments. The effective date of the transaction was January 1, 2014. Proceeds from the sale were used to reduce indebtedness under our credit agreement ("EXCO Resources Credit Agreement").

Compass divestiture

On October 31, 2014, we closed the sale of our entire interest in Compass to Harbinger Group, Inc. ("HGI") for $118.8 million in cash. We used a portion of the proceeds to reduce indebtedness under the EXCO Resources Credit Agreement. Prior to the closing of the sale, we reported our 25.5% interest in Compass using proportional consolidation. Our consolidated assets and liabilities were reduced by our proportionate share of Compass's net assets of $31.4 million which included our proportionate share of the Compass's indebtedness of $83.2 million on October 31, 2014. The sale of our interest in Compass did not significantly alter the relationship between our capitalized costs and proved reserves and was accounted for as an adjustment of capitalized costs with no gain or loss recognized in accordance with Rule 4-10(c)(6)(i) of Regulation S-X. As a result, our capitalized costs were further reduced by $87.4 million.

At the closing, EXCO and HGI terminated the existing operating and administrative services agreements and entered into a customary transition services agreement pursuant to which EXCO will provide certain transition services to Compass for up to nine months following the closing date. In addition, following the closing, EXCO will no longer be required to offer acquisition opportunities to Compass or any of its affiliates.

2013 acquisitions, divestitures and other significant events

Compass

On February 14, 2013, we formed Compass. 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 Compass, 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 Compass was 74.5% at its formation.

The contribution of oil and natural gas properties to Compass significantly altered the relationship between our capitalized costs and proved reserves. 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, Compass entered into an agreement to purchase the remaining shallow Cotton Valley assets in East Texas/North Louisiana 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 Compass. The transaction closed on March 5, 2013 and was funded with borrowings from Compass's credit agreement.

Permian Basin 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.

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. 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 the short-term nature of these liabilities.

Pro forma results of operations - The following table reflects the unaudited pro forma results of operations as though the acquisition of the Haynesville and Eagle Ford assets 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) (1)	$ 38,663	$ (1,398,169)
Basic earnings (loss) per share	$ 0.18	$ (6.52)
Diluted earnings (loss) per share	$ 0.17	$ (6.52)

(1) Net loss for the year ended December 31, 2012 was primarily due to the impairment of our oil and natural gas properties due to the significant decline in natural gas prices.

KKR Participation Agreement

In connection with closing the acquisition of the Eagle Ford assets, we entered into a participation agreement with 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 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.

Under the Participation Agreement, EXCO is required to offer to purchase our joint venture partner's 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 Participation Agreement, subject to specific well criteria and return hurdles. These acquisitions are expected to increase the borrowing base under the revolving commitment of the EXCO Resources Credit Agreement and are expected to be funded with borrowings under the EXCO Resources Credit Agreement, cash flows from operations, or other financing arrangements. Our joint venture partner has the right to participate in certain wells drilled in the Eagle Ford shale outside of the core area, as defined under the Participation Agreement, however these wells are not included as part of the acquisition program. If our joint venture partner elects to participate in certain wells outside of our core area, we will share equally in the working interest of the well.

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%. We recorded an equity investment of $13.4 million, net of a discount for a control premium, in Azure which is 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 EXCO Resources Credit Agreement. 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.

2012 acquisitions and divestitures

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.

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 losses or gains only arise from payments made or received on monthly settlements of contracts or if we terminate a contract prior to its expiration. We do not designate our derivative financial instruments as hedging instruments for financial accounting purposes and, as a result, we recognize the change in the respective instruments' fair value in earnings.

The table below outlines the classification of our derivative financial instruments on our Condensed Consolidated Balance Sheets and their financial impact on our Condensed Consolidated Statements of Operations.

Fair Value of Derivative Financial Instruments

(in thousands)	December 31, 2014	December 31, 2013
Derivative financial instruments - Current assets	$ 97,278	$ 8,226
Derivative financial instruments - Long-term assets	2,138	6,829
Derivative financial instruments - Current liabilities	(892)	(11,919)
Derivative financial instruments - Long-term liabilities	—	(9,671)
Net derivative financial instruments	$ 98,524	$ (6,535)

The Effect of Derivative Financial Instruments

(in thousands)	Year Ended December 31, 2014	2013	2012
Gain (loss) on derivative financial instruments	$ 87,665	$ (320)	$ 66,133

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 Condensed Consolidated Balance Sheets fair value amounts.

Our oil and natural gas derivative instruments are comprised of the following instruments:

Swaps: These contracts allow us to receive a fixed price and pay a floating market price to the counterparty for the hedged commodity.

Basis swaps: These 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 WTI oil prices.

Call options: These contracts 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.

Three-way collars: A three-way collar is a combination of options including a sold call, a purchased put and a sold put. These contracts allow us to participate in the upside of commodity prices to the ceiling of the call option and provide us with partial downside protection through the combination of the put options. If the market price is below the strike price of the purchased put at the time of settlement then the counterparty pays us the excess, unless the market price falls below the strike price of the sold put at which point the counterparty pays us the difference between the strike prices of the purchased put and sold put. If the market price is above the strike price of the sold call at the time of settlement, we pay the counterparty the excess. 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 counterparties to our derivative financial instruments that allow us to offset our asset position with our liability position in the event of a default by the counterparty.

The following table presents the volumes and fair value of our oil and natural gas derivative financial instruments as of December 31, 2014:

(in thousands, except prices)	Volume Mmbtu/ Bbl	Weighted average strike price per Mmbtu/Bbl	Fair value at December 31, 2014
Natural gas:			
Swaps:			
2015	42,888	$ 4.20	49,926
Call options:			
2015	20,075	4.29	(784)
Three-way collars:			
2015	27,375		10,205
Sold call		4.47	
Purchased put		3.83	
Sold put		3.33	
2016	10,980		2,138
Sold call		4.80	
Purchased put		3.90	
Sold put		3.40	
Total natural gas			$ 61,485
Oil:			
Swaps:			
2015	1,095	$ 91.09	36,797
Basis swaps:			
2015	91	6.10	350
Call options:			
2015	365	100.00	(108)
Total oil			$ 37,039
Total oil and natural gas derivative financial instruments			$ 98,524

At December 31, 2013, we had outstanding swap and call option contracts covering 112,348 Mmmbtu and 40,150 Mmmbtu, respectively, of natural gas and we had outstanding swap, basis swap and call option contracts covering 2,192 Mbbls, 274 Mbbls and 730 Mbbls, respectively, of oil.

At December 31, 2014, the average forward NYMEX WTI oil price per Bbl for the calendar year 2015 was $56.26, the average forward NYMEX Louisiana Light Sweet ("LLS") oil price per barrel for the calendar years 2015 was $58.51 and the average forward NYMEX Henry Hub natural gas prices per Mmbtu for the calendar years 2015 and 2016 were $3.01 and $3.46, respectively.

Our derivative financial instruments covered approximately 69% and 57% of production volumes for the years ended December 31, 2014 and 2013.

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. During the years ended December 31, 2014 and 2013 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, 2014 and 2013.

	December 31, 2014			
(in thousands)	**Level 1**	**Level 2**	**Level 3**	**Total**
Oil and natural gas derivative financial instruments................................	$ —	$ 98,524	$ —	$ 98,524

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

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

The valuation of our commodity price derivatives, represented by oil and natural gas swaps, basis swaps, call option and three-way collar 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 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, three-way collar and call option contracts for notional Mmbtus of natural gas at posted price indexes, including NYMEX HH swap and 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 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 approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to us for those periods.

The estimated fair values of our 7.5% senior unsecured notes due September 15, 2018 ("2018 Notes"), our 8.5% senior unsecured notes due April 15, 2022 ("2022 Notes") and the term loan under the EXCO Resources Credit Agreement ("Term Loan"), at December 31, 2014 and December 31, 2013 are presented below. The estimated fair values of the 2018 Notes, 2022 Notes and Term Loan have been calculated based on market quotes.

	December 31, 2014			
(in thousands)	**Level 1**	**Level 2**	**Level 3**	**Total**
2018 Notes	$ 558,750	$ —	$ —	$ 558,750
2022 Notes	373,500	—	—	373,500

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

6. Debt

Our total debt is summarized as follows:

(in thousands)	**December 31, 2014**	**December 31, 2013**
Revolving credit facility under EXCO Resources Credit Agreement	$ 202,492	$ 763,866
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	(5,957)	(7,293)
2022 Notes	500,000	—
Total debt excluding Compass	1,446,535	1,802,293
Compass Production Partners Credit Agreement	—	88,485
Total debt	1,446,535	1,890,778
Less amounts due within one year	—	31,866
Total debt due after one year	$ 1,446,535	$ 1,858,912

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

EXCO Resources Credit Agreement

As of December 31, 2014, the EXCO Resources Credit Agreement had $202.5 million of outstanding indebtedness, $900.0 million of available borrowing base and $690.9 million of unused borrowing base, net of letters of credit. The maturity date of the EXCO Resources Credit Agreement is July 31, 2018. 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. On December 31, 2014, the one month LIBOR was 0.2%, which resulted in an interest rate of approximately 1.9% on the revolving commitment.

We closed a rights offering and related private placement of our common shares on January 17, 2014 ("Rights Offering") and received gross proceeds of $272.9 million which we used to reduce the outstanding indebtedness under the EXCO Resources Credit Agreement, including the remainder of the asset sale requirement as well as a portion of the revolving commitment. See further discussion in "Note 13. Rights offering and other equity transactions". Upon repayment of the asset sale requirement, the interest rate on the revolving commitment decreased by 100 basis points.

On April 16, 2014, we closed an offering of $500.0 million in aggregate principal amount of senior unsecured notes and utilized the proceeds to fully repay the Term Loan. The remaining proceeds were used to reduce outstanding indebtedness under the revolving commitment of the EXCO Resources Credit Agreement. See further discussion of the 2022 Notes below.

On October 31, 2014 we closed the sale of our entire interest in Compass. The transaction resulted in a reduction to our consolidated indebtedness by our proportionate share of Compass's indebtedness, which at closing was $83.2 million. In addition, we used a portion of our proceeds from this transaction to reduce the outstanding indebtedness under the EXCO Resources Credit Agreement. Compass was not a guarantor to the EXCO Resources Credit Agreement, 2018 Notes or the 2022 Notes. As such, our borrowing base was not affected by this sale. See further discussion in "Note 3. Acquisitions, divestitures, and other significant events".

On February 6, 2015, we amended the EXCO Resources Credit Agreement which decreased our borrowing base from $900.0 million to $725.0 million as a result of the recent decline in oil and natural gas prices. The next borrowing base redetermination for the EXCO Resources Credit Agreement will occur in August 2015. Subsequent redeterminations will occur semi-annually with us and the lenders having the right to request interim unscheduled redeterminations in certain circumstances. In addition, the financial covenants were amended to include an interest coverage ratio and senior secured indebtedness to consolidated EBITDAX ratio. The leverage ratio was suspended until the fourth quarter of 2016 and the ratio requirements thereafter were modified.

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 shares, of which $7.6 million has been repurchased to date. We repurchased 38,821 shares for $0.1 million in 2014 that were tendered by employees to satisfy minimum tax withholding amounts for restricted share awards. There were no share repurchases during 2013 and 2012.

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 shares. In July 2014, we amended the EXCO Resources Credit Agreement to provide that we may declare and pay cash dividends on our common shares in an amount not to exceed a cumulative total of $75.0 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 and 2022 Notes.

As of December 31, 2014, we were in compliance with the financial covenants contained in the EXCO Resources Credit Agreement, which required 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.

On February 6, 2015, we amended the EXCO Resources Credit Agreement which requires that we:

- maintain a consolidated current ratio of at least 1.0 to 1.0 as of the end of any fiscal quarter;
- maintain a ratio of consolidated EBITDAX to consolidated interest expense ("Interest Coverage Ratio") of at least 2.0 to 1.0 as of the end of any fiscal quarter;
- not permit our ratio of senior secured indebtedness to consolidated EBITDAX ("Secured Indebtedness Ratio") to be greater than 2.50 to 1.0 as of the end of any fiscal quarter; and
- not permit our ratio of consolidated funded indebtedness to consolidated EBITDAX ("Leverage Ratio") as of the end of any fiscal quarter to be greater than the ratio set forth for the following periods:

Period	Ratio
The fiscal quarter ending December 31, 2016	6.00 to 1.00
The fiscal quarter ending March 31, 2017 and June 30, 2017	5.75 to 1.00
The fiscal quarter ending September 30, 2017	5.25 to 1.00
The fiscal quarter ending December 31, 2017	4.75 to 1.00
Each fiscal quarter ending thereafter	4.50 to 1.00

The Leverage Ratio will be calculated based on the consolidated EBITDAX for the trailing four quarter period ending on the last day of such fiscal quarter, except, the consolidated EBITDAX for quarter period ending December 31, 2016 shall be consolidated EBITDAX for quarter ending December 31, 2016 multiplied by 4.00, consolidated EBITDAX for the two quarter period ending March 31, 2017 shall be consolidated EBITDAX for such period multiplied by 2.00, and consolidated EBITDAX for the three quarter period ending June 30, 2017 shall be consolidated EBITDAX for such period multiplied by 4/3.

2018 Notes

The 2018 Notes are guaranteed on a senior unsecured basis by a majority of EXCO's subsidiaries, with the exception of certain non-guarantor subsidiaries and our jointly-held equity investments with BG Group. Our equity investments with BG Group, other than OPCO, have been designated as unrestricted subsidiaries under the indenture governing the 2018 Notes.

As of December 31, 2014, $750.0 million in principal was outstanding on the 2018 Notes. The unamortized discount on the 2018 Notes at December 31, 2014 was $6.0 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 shares;
- pay dividends on our capital stock 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.

2022 Notes

On April 16, 2014, we completed a public offering of $500.0 million in aggregate principal amount of senior unsecured notes due April 15, 2022. We received net proceeds of approximately $490.0 million after offering fees and expenses. The 2022 Notes were issued at 100.0% of the principal amount and bear interest at a rate of 8.5% per annum, payable in arrears on April 15 and October 15 of each year. We used a portion of the net proceeds from the 2022 Notes offering to repay the $297.8 million outstanding principal balance on the Term Loan and the remaining proceeds were used to reduce outstanding indebtedness under the revolving commitment of the EXCO Resources Credit Agreement.

The 2022 Notes rank equally in right of payment to any existing and future senior unsecured indebtedness of the Company (including the 2018 Notes) and are guaranteed on a senior unsecured basis by EXCO's consolidated subsidiaries that are guarantors of the indebtedness under the EXCO Resources Credit Agreement. The 2022 Notes were issued under the same base indenture governing the 2018 Notes and the supplemental indenture governing the 2022 Notes contains similar covenants to those in the supplemental indenture governing the 2018 Notes.

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 2022 Notes.

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 2015 and into 2016, there are certain risks arising from depressed oil and natural gas prices and declines in production volumes that could impact our liquidity and ability to meet debt covenants in future periods. Our ability to maintain compliance with our debt covenants may be negatively impacted when oil and/or natural gas prices remain depressed for an extended period of time. 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. The borrowing base redetermination process considers assumptions related to future commodity prices; therefore, our borrowing capacity could be negatively impacted by further declines in oil and natural gas prices. Accordingly, our ability to effectively execute our corporate strategies and manage our operating, general and administrative expenses and capital expenditure programs is critical to our financial condition, liquidity and our results of operations.

If we are not able to meet our debt covenants in future periods, 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, 2018 Notes and 2022 Notes could result in an event of default, which could adversely affect our business, financial condition and results of operations.

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

The following table presents our future minimum obligations under our commercial commitments as of December 31, 2014. The commitments do not include those of our equity method investments. Gathering and firm transportation services presented in the following tables represent our gross commitments under these contracts and a portion of these costs will be incurred by working interest and other owners.

(in thousands)	Gathering and firm transportation services	Other fixed commitments	Drilling contracts	Operating leases and other	Total
2015	$ 136,040	$ 17,332	$ 22,191	$ 5,912	$ 181,475
2016	133,429	13,253	2,538	5,223	154,443
2017	132,860	5,443	—	3,847	142,150
2018	129,140	3,210	—	3,094	135,444
2019	89,060	2,403	—	3,051	94,514
Thereafter	101,618	3,530	—	1,623	106,771
Total	$ 722,147	$ 45,171	$ 24,729	$ 22,750	$ 814,797

We lease our offices and certain equipment. Our rental expenses were approximately $5.1 million, $5.9 million and $6.8 million for the years ended December 31, 2014, 2013 and 2012, respectively. We have also entered into various drilling rig contracts primarily to develop our Haynesville and Eagle Ford shale assets. The actual drilling costs under these contracts will be incurred by working interest owners in the development of the related properties. These contracts are short-term in nature and are dependent on our planned drilling program.

We have entered into firm transportation and gathering agreements with pipeline companies to facilitate sales from our East Texas/North Louisiana production and report these costs as a component of gathering and transportation expenses. At December 31, 2014, our firm transportation and gathering agreements covered the following gross volumes of natural gas:

(in Bcf)	Firm transportation services	Gathering services
2015	293	110
2016	272	110
2017	269	110
2018	269	100
2019	269	—
Thereafter	299	—
Total	1,671	430

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.

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 match 100% of employee contributions. Our matching contributions were $7.1 million, $8.8 million and $9.4 million for the years ended December 31, 2014, 2013 and 2012, respectively.

10. Earnings per share

The following table presents the basic and diluted earnings (loss) per share computations for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
(in thousands, except per share data)	2014	2013	2012
Basic net income (loss) per common share:			
Net income (loss)	$ 120,669	$ 22,204	$ (1,393,285)
Weighted average common shares outstanding	268,258	215,011	214,321
Net income (loss) per basic common share	$ 0.45	$ 0.10	$ (6.50)
Diluted net income (loss) per common share:			
Net income (loss)	$ 120,669	$ 22,204	$ (1,393,285)
Weighted average common shares outstanding	268,258	215,011	214,321
Dilutive effect of:			
Stock options	—	—	—
Restricted shares and restricted share units	118	420	—
Subscription rights	—	15,481	—
Weighted average common shares and common share equivalents outstanding	268,376	230,912	214,321
Net income (loss) per diluted common share	$ 0.45	$ 0.10	$ (6.50)

The computation of diluted EPS excluded 14,316,409, 55,524,191 and 17,242,306 antidilutive common share equivalents for the years ended December 31, 2014, 2013 and 2012, respectively. The antidilutive common share equivalents for the year ended December 31, 2014 and 2012 primarily related to out-of-the-money stock options, unvested restricted share units and unvested restricted share awards. The antidilutive common share equivalents for the year ended December 31, 2013 primarily consisted of subscription rights outstanding, out-of-the-money stock options and unvested restricted shares.

11. Stock options and awards

Description of plan

Our 2005 Incentive Plan is a shareholder-approved plan authorizing the issuance of up to 45,500,000 restricted shares, restricted share units and stock options. As of December 31, 2014 and 2013, there were 19,763,916 and 21,118,292 shares, respectively, available for issuance under the 2005 Incentive Plan. Option grants count as one share against the total number of shares we have available for grant and restricted share 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 shares, excluding certain market-based restricted share awards discussed below, 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, restricted share awards and restricted share units as of December 31, 2014 was $20.4 million. Of this amount, $3.1 million related to unvested options and will be recognized over a weighted average period of 1.7 years and $17.3 million related to unvested restricted share units and awards will be recognized over a weighted average period of 2.2 years.

The following is a reconciliation of our share-based compensation expense for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Share-based compensation expense	$ 4,962	$ 10,748	$ 8,926
Share-based compensation capitalized	5,498	7,288	7,513
Total share-based compensation	$ 10,460	$ 18,036	$ 16,439

We did not recognize a tax benefit attributable to our share-based compensation for the years ended December 31, 2014, 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 3.7 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, 2014, 2013 and 2012:

	Stock Options	Weighted average exercise price per share	Weighted average remaining terms (in years)	Aggregate intrinsic value
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		
Granted	141,525	5.24		
Forfeitures	(1,700,250)	12.71		
Exercised	(2,500)	5.22		
Options outstanding at December 31, 2014	10,150,518	$ 12.58	3.7	$ —
Options exercisable at December 31, 2014	9,181,306	$ 13.15	3.2	$ —

The weighted average fair value of stock options on the date of the grant during the years ended December 31, 2014, 2013 and 2012 was $2.23, $3.53 and $3.96, respectively. The total intrinsic value of stock options exercised for the years ended December 31, 2014, 2013 and 2012 was $0.0 million, $0.2 million and $0.1 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 shares on the date of grant. The following assumptions were used for the options included in the table above, for the years ended December 31:

	2014	2013	2012
Expected life	7.5 years	3.8 to 7.5 years	3.8 to 7.5 years
Risk-free rate of return	2.25 - 2.61 %	0.48 - 2.49 %	0.56 - 1.64 %
Volatility	59.46 - 59.61 %	49.47 - 59.86 %	57.34 - 60.24 %
Dividend yield	3.36 - 4.34 %	2.27 - 3.87 %	0.52 - 1.92 %

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 shares 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 share awards

Our service-based restricted share awards are valued at the closing price of our common shares on the date of grant and vest over a range of two to five years. A summary of our service-based restricted share activity for the years ended December 31, 2014, 2013 and 2012 are as follows:

	Shares	Weighted average grant date fair value per share
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
Granted	1,339,782	5.20
Vested	(1,109,866)	9.79
Forfeited	(280,301)	6.89
Non-vested shares outstanding at December 31, 2014	1,877,929	$ 6.40

Market-based restricted share awards

On August 13, 2013, EXCO's officers were granted a market-based restricted share award. The total number of shares 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 shares will be vested following any 30 consecutive trading days in which the Company's common shares equals or exceeds $15.00 per share ("Target Price Awards"). Shares vest over a two year period and are subject to other vesting provisions depending on when the attainment date occurs. No such awards were granted in 2014.

During the third quarter of 2014, EXCO's officers were granted 820,317 restricted share units which have a vesting percentage between 0% and 200% depending on EXCO's total shareholder return ("TSR") in comparison to an identified peer group. These units will vest on the third anniversary of the date of grant, subject to the achievement of certain criteria. Total compensation expense will be recognized over the vesting period using the straight-line method.

The grant date fair values of our market-based restricted share awards and restricted share units were determined using a Monte Carlo model which uses company-specific inputs to generate different stock price paths.

A summary of our market-based restricted share activity for the years ended December 31, 2014 and 2013 is as follows:

	Target Price Awards		TSRs	
	Shares	Weighted average grant date fair value per share	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	—	$ —
Granted	—	—	820,317	7.33
Vested	—	—	—	—
Forfeited	(73,200)	6.36	(104,167)	7.33
Non-vested shares outstanding at December 31, 2014	401,400	$ 6.36	716,150	$ 7.33

12. Income taxes

The income tax provision attributable to our income (loss) before income taxes for the years ended December 31, 2014, 2013 and 2012, consisted of the following:

(in thousands)	Year ended December 31, 2014	2013	2012
Current:			
Federal	$ —	$ —	$ —
State	—	—	—
Total current income tax (benefit)	$ —	$ —	$ —
Deferred:			
Federal	$ 45,797	$ 25,626	$ (485,543)
State	18,960	3,239	(59,406)
Valuation allowance	(64,757)	(28,865)	544,949
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 2034. NOLs and alternative minimum tax credits available for utilization as of December 31, 2014 were approximately $2.0 billion and $1.5 million, respectively. In addition, we generated a net capital loss of approximately $105.6 million during the year ended December 31, 2014 as a result of the sale of our interest in Compass.

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, 2014	December 31, 2013
Current deferred tax assets (liabilities):		
Derivative financial instruments	$ (38,519)	$ —
Other	2,584	5,332
Valuation allowance	—	(5,332)
Net current deferred tax assets (liabilities)	(35,935)	—
Non-current deferred tax assets:		
Net operating loss and AMT credits carryforwards	$ 781,899	$ 737,399
Capital loss carryforwards	40,356	—
Share-based compensation	14,856	16,060
Oil and natural gas properties, gathering assets, and equipment	—	47,491
Goodwill	5,419	9,812
Derivative financial instruments	—	2,102
Investment in partnerships	72,988	73,328
Other	84	85
Total non-current deferred tax assets	915,602	886,277
Valuation allowance	(826,852)	(886,277)
Total non-current deferred tax assets	88,750	—
Non-current deferred tax liabilities:		
Oil and natural gas properties, gathering assets, and equipment	$ (51,961)	$ —
Derivative financial instruments	(854)	—
Total non-current deferred tax liabilities	(52,815)	—
Net non-current deferred tax assets (liabilities)	$ 35,935	$ —

The reversal of the temporary differences related to the net current deferred tax liability is expected to be offset by taxable losses generated in the same fiscal year as the reversal. If we do not generate taxable losses in the same fiscal year to offset the reversal of the temporary differences then we will utilize our NOLs to offset the taxable income.

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, 2014, 2013 and 2012 is presented in the following table:

	Year Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Federal income taxes (benefit) provision at statutory rate of 35%	$ 42,234	$ 7,772	$ (487,649)
Increases (reductions) resulting from:			
Goodwill	—	16,382	—
Adjustments to the valuation allowance	(64,757)	(28,865)	544,949
Non-deductible compensation	3,409	1,328	1,893
State taxes net of federal benefit	3,464	3,239	(59,406)
State tax rate change	15,496	—	—
Other	154	144	213
Total income tax provision	$ —	$ —	$ —

During both 2014 and 2013, both federal and state income taxes were reduced to zero by a corresponding decrease to the valuation allowance previously recognized against net deferred tax assets. The net result was no income tax provision for both 2014 and 2013.

During 2012, our net loss was greatly impacted by the impairments of our proved oil and natural gas properties 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.

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, 2014, 2013 and 2012, 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 a corporate consolidated income tax return for U.S. federal income tax purposes and file income tax return in various states. With few exceptions, we are no longer subject to U.S. federal and state and local examinations by tax authorities for years before 2006. 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. During 2014 the Internal Revenue Service completed the exam on the corporate return and on one of the two pass-through entities. No changes were made to either the corporate or partnership return as originally filed as a result of the exams. We do not anticipate that the remaining tax exam on the pass-through entity will result in a material change to the tax return as originally filed.

13. Related party transactions

OPCO serves as the operator of our wells in the Appalachia JV and we advance funds to OPCO on an as needed basis. OPCO may distribute any excess cash equally between us and BG Group when its operating cash flows are sufficient to meet its capital requirements. 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, 2014, 2013 and 2012 these transactions included the following:

	Year Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Advances to OPCO	$ —	$ 28,378	$ 76,729
Amounts received from OPCO	53,002	43,632	52,206

As of December 31, 2014 and 2013, the amounts owed under the service agreements were as follows:

(in thousands)	December 31, 2014	December 31, 2013
Amounts due to EXCO (1)	$ 2,799	$ 2,283
Amounts due from EXCO (1)	—	—

(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 to OPCO 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

Investment accounts managed by Invesco Advisers, Inc. were lenders under the Term Loan of the EXCO Resources Credit Agreement. Invesco Advisers, Inc. is an indirect owner of WL Ross & Co. LLC ("WL Ross"). Wilbur L. Ross, Jr., the Chairman and Chief Executive Officer at WL Ross, serves on EXCO's board of directors. Invesco Advisers, Inc. held approximately 10% of total borrowings under the Term Loan until the Term Loan was repaid in April 2014 with proceeds received from the issuance of the 2022 Notes.

As discussed in "Note 15. Rights offering and other equity transactions", we entered into investment agreements and closed a related private placement of our common shares with certain affiliates of WL Ross and Hamblin Watsa Investment Counsel Ltd. ("Hamblin Watsa"). Wilbur L. Ross, Jr., the Chairman and Chief Executive Officer of WL Ross, and Samuel A. Mitchell, Managing Director of Hamblin Watsa, both of whom serve on EXCO's board of directors.

14. Dividends

Total dividends paid to our shareholders in 2014, 2013 and 2012 were $41.1 million, $43.2 million, and $34.4 million, respectively. On December 15, 2014, our board of directors suspended the cash dividend and did not approve a cash dividend for the fourth quarter of 2014.

Any future declaration of dividends, as well as the establishment of record and payment dates, will depend on our earnings, capital requirements, financial condition, prospects and other factors our board of directors may deem relevant.

15. Rights Offering and other equity transactions

On December 19, 2013, the Company granted subscription rights to holders of common shares 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 shares 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 our common shares 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 our common shares. 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.

Preferred Shares

We canceled all classes of our preferred shares in 2014. We have 10,000,000 preferred shares authorized with no preferred shares issued and outstanding. Our issued and outstanding shares of capital stock consist solely of common shares.

16. Condensed consolidating financial statements

As of December 31, 2014, the majority of EXCO's subsidiaries were guarantors under the EXCO Resources Credit Agreement and the indenture governing the 2018 Notes and 2022 Notes. All of our non-guarantor subsidiaries were considered unrestricted subsidiaries under the indenture governing the 2018 Notes and 2022 Notes, with the exception of our equity investment in OPCO.

Set forth below are condensed consolidating financial statements of EXCO, the guarantor subsidiaries and the non-guarantor subsidiaries. The 2018 Notes and 2022 Notes, which were issued by EXCO Resources, Inc., are jointly and severally guaranteed by some of our subsidiaries (referred to as Guarantor Subsidiaries). For purposes of this footnote, EXCO Resources, Inc. is referred to as Resources to distinguish it from the Guarantor Subsidiaries. Each of the Guarantor Subsidiaries is a 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, 2014

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 86,837	$ (40,532)	$ —	$ —	$ 46,305
Restricted cash	—	23,970	—	—	23,970
Other current assets	110,145	150,346	—	—	260,491
Total current assets	196,982	133,784	—	—	330,766
Equity investments	—	—	55,985	—	55,985
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties and development costs not being amortized	—	276,025	—	—	276,025
Proved developed and undeveloped oil and natural gas properties	335,838	3,516,235	—	—	3,852,073
Accumulated depletion	(330,771)	(2,083,690)	—	—	(2,414,461)
Oil and natural gas properties, net	5,067	1,708,570	—	—	1,713,637
Gathering, office, field and other assets, net	1,269	23,375	—	—	24,644
Investments in and advances to affiliates, net	1,746,931	—	—	(1,746,931)	—
Deferred financing costs, net	30,636	—	—	—	30,636
Derivative financial instruments	2,138	—	—	—	2,138
Goodwill	13,293	149,862	—	—	163,155
Deferred income taxes	35,935	—	—	—	35,935
Total assets	$ 2,032,251	$ 2,015,591	$ 55,985	$ (1,746,931)	$ 2,356,896
Liabilities and shareholders' equity					
Current liabilities	$ 75,441	$ 289,930	$ —	$ —	$ 365,371
Long-term debt	1,446,535	—	—	—	1,446,535
Deferred income taxes	—	—	—	—	—
Other long-term liabilities	271	34,715	—	—	34,986
Payable to parent	—	2,058,683	—	(2,058,683)	—
Total shareholders' equity	510,004	(367,737)	55,985	311,752	510,004
Total liabilities and shareholders' equity	$ 2,032,251	$ 2,015,591	$ 55,985	$ (1,746,931)	$ 2,356,896

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 assets, net	3,481	24,639	22,248	—	50,368
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
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 STATEMENT OF OPERATIONS

For the year ended December 31, 2014

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 3,649	$ 614,889	$ 41,731	$ —	$ 660,269
Costs and expenses:					
Oil and natural gas production	394	77,334	16,598	—	94,326
Gathering and transportation	—	97,784	3,790	—	101,574
Depletion, depreciation and amortization	3,174	244,761	15,634	—	263,569
Impairment of oil and natural gas properties	—	—	—	—	—
Accretion of discount on asset retirement obligations	16	2,107	567	—	2,690
General and administrative	(3,342)	66,686	2,576	—	65,920
Other operating items	(134)	5,459	(10)	—	5,315
Total costs and expenses	108	494,131	39,155	—	533,394
Operating income	3,541	120,758	2,576	—	126,875
Other income (expense):					
Interest expense, net	(92,049)	—	(2,235)	—	(94,284)
Gain on derivative financial instruments	87,565	—	100	—	87,665
Other income	226	—	15	—	241
Equity income	—	—	172	—	172
Net earnings from consolidated subsidiaries	121,386	—	—	(121,386)	—
Total other income (expense)	117,128	—	(1,948)	(121,386)	(6,206)
Income before income taxes	120,669	120,758	628	(121,386)	120,669
Income tax expense	—	—	—	—	—
Net income	$ 120,669	$ 120,758	$ 628	$ (121,386)	$ 120,669

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 (loss)	(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:					
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 CASH FLOWS

For the year ended December 31, 2014

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by (used in) operating activities	$ (84,067)	$ 428,029	$ 18,131	$ —	$ 362,093
Investing Activities:					
Additions to oil and natural gas properties, gathering assets and equipment and property acquisitions	(2,531)	(395,974)	(4,061)	—	(402,566)
Restricted cash	—	(3,400)	—	—	(3,400)
Equity method investments	—	1,749	—	—	1,749
Proceeds from disposition of property and equipment	99,612	95,594	(7,551)	—	187,655
Distributions received from Compass	5,856	—	—	(5,856)	—
Net changes in advances to joint ventures	—	(5,026)	—	—	(5,026)
Advances/investments with affiliates	125,612	(125,612)	—	—	—
Net cash provided by (used in) investing activities	228,549	(432,669)	(11,612)	(5,856)	(221,588)
Financing Activities:					
Borrowings under credit agreements	100,000	—	—	—	100,000
Repayments under credit agreements	(959,874)	—	(5,096)	—	(964,970)
Proceeds received from issuance of 2022 Notes	500,000	—	—	—	500,000
Proceeds from issuance of common shares, net	271,773	—	—	—	271,773
Payment of common share dividends	(41,060)	—	—	—	(41,060)
Compass cash distribution	—	—	(5,856)	5,856	—
Deferred financing costs and other	(10,188)	—	(102)	—	(10,290)
Payments of common shares repurchased	(136)	—	—	—	(136)
Net cash used in financing activities	(139,485)	—	(11,054)	5,856	(144,683)
Net increase (decrease) in cash	4,997	(4,640)	(4,535)	—	(4,178)
Cash at beginning of period	81,840	(35,892)	4,535	—	50,483
Cash at end of period	$ 86,837	$ (40,532)	$ —	$ —	$ 46,305

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 from Compass	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 shares, net	1,712	—	—	—	1,712
Payment of common share dividends	(43,214)	—	—	—	(43,214)
Compass 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

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	(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 the credit agreements	53,000	—	—	—	53,000
Repayments under the credit agreements	(93,000)	—	—	—	(93,000)
Proceeds from issuance of common shares, net	1,968	—	—	—	1,968
Payment of common share 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

17. Quarterly financial data (unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2014 and 2013:

(in thousands, except per share amounts)	Quarter 1st	2nd	3rd	4th
2014				
Oil and natural gas revenues	$ 198,472	$ 182,966	$ 151,042	$ 127,789
Operating income (loss)	57,423	43,312	22,799	3,341
Net income (loss)	$ (4,606)	$ 2,293	$ 41,569	$ 81,413
Basic earnings (loss) per share:				
Net income (loss)	$ (0.02)	$ 0.01	$ 0.15	$ 0.30
Weighted average shares	260,716	270,492	270,631	271,053
Diluted earnings (loss) per share:				
Net income (loss)	$ (0.02)	$ 0.01	$ 0.15	$ 0.30
Weighted average shares	260,716	271,226	272,066	271,053
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

(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 3. Acquisitions, divestitures and other significant events" 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 Compass. See "Note 3. Acquisitions, divestitures and other significant events" for further discussion.

18. 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, 2014, 2013 and 2012 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
2014:	
Proved property acquisition costs	$ 10,562
Unproved property acquisition costs	—
Total property acquisition costs	10,562
Development	354,199
Exploration costs (1)	5,906
Lease acquisitions and other	9,681
Capitalized asset retirement costs	576
Depletion per Boe	$ 11.42
Depletion per Mcfe	$ 1.90
2013:	
Proved property acquisition costs	$ 754,370
Unproved property acquisition costs	232,020
Total property acquisition costs (2)	986,390
Development	231,447
Exploration costs (3)	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 (4)	57,325
Lease acquisitions and other (5)	44,546
Capitalized asset retirement costs	971
Depletion per Boe	$ 9.11
Depletion per Mcfe	$ 1.52

(1) Exploration costs in 2014 include $5.9 million in the Bossier shale in North Louisiana.

(2) Acquisition costs in 2013 include the acquisition of properties in the Haynesville and Eagle Ford shales and our proportionate share of Compass's acquisition of shallow Cotton Valley assets.

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

(4) Exploration costs in 2012 include $40.1 million in the Haynesville shale $17.2 million in the Marcellus shale.

(5) Lease acquisition costs in 2012 are net of acreage reimbursements from BG Group totaling $2.1 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)	Mmcfe (11)
December 31, 2011	6,354	1,291,464	—	1,329,588
Purchase of reserves in place	—	—	—	—
Discoveries and extensions (1)	492	96,615	424	102,111
Revisions of previous estimates:				
Changes in price	(110)	(466,238)	—	(466,898)
Other factors (2)	(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	5,570	936,132	6,639	1,009,386
Purchase of reserves in place (3)	16,022	290,933	2,201	400,271
Discoveries and extensions (4)	5,960	46,834	513	85,672
Revisions of previous estimates:				
Changes in price	457	272,614	686	279,472
Other factors (5)	(3,219)	(106,695)	(741)	(130,455)
Sales of reserves in place (6)	(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
Purchase of reserves in place (7)	—	7,316	—	7,316
Discoveries and extensions (8)	4,164	69,902	107	95,528
Revisions of previous estimates:				
Changes in price	45	167,302	127	168,334
Other factors (9)	1,737	120,850	(8)	131,224
Sales of reserves in place (10)	(1,401)	(105,841)	(2,144)	(127,111)
Production	(2,236)	(120,980)	(224)	(135,740)
December 31, 2014	17,687	1,155,028	441	1,263,796

Estimated Quantities of Proved Developed and Proved Undeveloped Reserves

	Oil (Mbbls)	Natural Gas (Mmcf)	Natural Gas Liquids (Mbbls)	Mmcfe
Proved developed:				
December 31, 2014	14,429	502,314	387	591,210
December 31, 2013	11,274	657,116	2,088	737,291
December 31, 2012	4,371	917,326	4,784	972,256
Proved undeveloped:				
December 31, 2014	3,258	652,714	54	672,586
December 31, 2013	4,104	359,363	495	386,954
December 31, 2012	1,199	18,806	1,855	37,130

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

(2) 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 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.

(3) 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 Compass's acquisition of shallow Cotton Valley assets in East Texas/ North Louisiana.

(4) New discoveries and extensions in 2013 include 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 Compass in the Permian Basin, and 1,486 Mmcfe for shale properties in the Permian Basin.

(5) Total revisions due to Other factors were 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.

(6) Sales of reserves in place in 2013 include 327,608 Mmcfe as a result of our contribution of properties to Compass and 30,582 Mmcfe from the sale of undeveloped properties in the Eagle Ford in connection with the Participation Agreement.

(7) Purchases of reserves in place in 2014 consist primarily of our acquisition of certain proved developed producing properties in the Shelby area of East Texas.

(8) New discoveries and extensions in 2014 included 48,698 Mmcfe in the Haynesville shale, 26,148 Mmcfe in the Eagle Ford Shale and 19,664 in the Bossier shale. The discoveries and extensions within the Haynesville and Bossier shales primarily related to our development of properties within the Shelby area of East Texas.

(9) Total revisions due to Other factors include upward revisions of approximately 67,095 Mmcfe in the Shelby area, approximately 45,878 Mmcfe in the Appalachia region, and approximately 5,836 Mmcfe in the Holly area. The upward revisions were primarily due to improved well performance resulting from enhanced well designs and completion techniques.

(10) Sales of reserves in place in 2014 consist primarily of the sale of our entire interest in Compass.

(11) The above reserves do not include our equity interest in OPCO, which was not significant in any period presented.

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, 2014:		
Future cash inflows	$	6,097,207
Future production costs		2,094,796
Future development costs		1,124,873
Future income taxes		—
Future net cash flows		2,877,538
Discount of future net cash flows at 10% per annum		1,334,951
Standardized measure of discounted future net cash flows	$	1,542,587
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

During recent years, prices paid for oil and natural gas have fluctuated significantly. The reference prices at December 31, 2014, 2013 and 2012 used in the above table, were $94.99, $96.78 and $94.71 per Bbl of oil, respectively, and $4.35, $3.67 and $2.76 per Mmbtu of natural gas, respectively. The reference price at December 31, 2014, 2013 and 2012 used in the above table was $33.03 $39.92 and $46.57 per Bbl for NGLs, respectively. Each of the reference prices for oil and natural gas were adjusted for quality factors and regional 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, 2014:	
Sales and transfers of oil and natural gas produced	$ (464,369)
Net changes in prices and production costs	279,944
Extensions and discoveries, net of future development and production costs	196,796
Development costs during the period	189,155
Changes in estimated future development costs	(254,737)
Revisions of previous quantity estimates	412,296
Sales of reserves in place	(148,226)
Purchase of reserves in place	13,507
Accretion of discount before income taxes	125,227
Changes in timing and other	(59,279)
Net change in income taxes	—
Net change	$ 290,314
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	(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)

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	2014	2013	2012	2011 and prior
Property acquisition costs	$ 228,553	$ 9,737	$ 71,524	$ 3,038	$ 144,254
Exploration and development	16,366	10,797	73	524	4,972
Capitalized interest	31,106	11,871	8,737	6,796	3,702
Total	$ 276,025	$ 32,405	$ 80,334	$ 10,358	$ 152,928

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, 2014 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, 2014, using criteria established in *Internal Control-Integrated Framework (2013)* 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, 2014 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.

Date: February 25, 2015	EXCO RESOURCES, INC.
	(Registrant)

EXCO RESOURCES, INC.
(Registrant)

Date: February 25, 2015

/s/ Harold L. Hickey

Harold L. Hickey
President and Chief Operating Officer

/s/ Richard A. Burnett

Richard A. Burnett
Vice President, Chief Financial Officer
and Chief Accounting Officer

/s/ Jeffrey D. Benjamin

Jeffrey D. Benjamin
Non-Executive Chairman

/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	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.
2.2	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.
2.3	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.
2.4	Purchase Agreement, dated October 6, 2014, by and among EXCO Resources, Inc., a Texas corporation, EXCO Operating Company, LP, a Delaware limited partnership, EXCO Holding MLP, Inc., a Texas corporation, HGI Energy Holdings, LLC, a Delaware limited liability company, Compass Production Services, LLC, a Delaware limited liability company, and Compass Energy Operating, LLC, a Delaware limited liability company, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated October 6, 2014 and filed on October 10, 2014 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 (File No. 001-32743), dated March 4, 2009 and filed on March 6, 2009 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	Third Supplemental Indenture, dated April 16, 2014, by and among EXCO Resources, Inc., certain of its subsidiaries and Wilmington Trust Company, as trustee, including the form of 8.500% Senior Notes due 2022, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated April 11, 2014 and filed on April 16, 2014 and incorporated by reference herein.
4.5	Fourth Supplemental Indenture, dated May 12, 2014, by and among EXCO Resources, Inc., EXCO Land Company, LLC and Wilmington Trust Company, as trustee, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2014 and filed on July 30, 2014 and incorporated by reference herein.
4.6	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 dated 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 Form of Performance-Based Restricted Stock Unit 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 June 30, 2014 and filed on July 3, 2014 and incorporated by reference herein.*

10.6 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.*

10.7 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.*

10.8 Amendment Number One to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc., filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2009 filed on February 24, 2010 and incorporated by reference herein.*

10.9 Amendment Number Two to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc., effective as of May 22, 2014, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 22, 2014 and filed on May 29, 2014 and incorporated by reference herein.*

10.10	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.
10.11	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.*
10.12	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.*
10.13	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.*
10.14	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.*
10.15	Joint Development Agreement, dated August 14, 2009, by and among BG US Production Company, LLC, EXCO Operating Company, LP and EXCO Production Company, LP, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 11, 2009 and filed on August 17, 2009 and incorporated by reference herein.
10.16	Amendment to Joint Development Agreement, dated February 1, 2011, by and among BG US Production Company, LLC and EXCO Operating Company, LP, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2010 filed February 24, 2011 and incorporated by reference herein.
10.17	Amendment to Joint Development Agreement, dated October 14, 2014, by and among BG US Production Company, LLC and EXCO Operating Company, LP, filed herewith.
10.18	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.
10.19	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.
10.20	Amendment to Joint Development Agreement, dated October 14, 2014, by and among EXCO Production Company (PA), LLC, EXCO Production Company (WV), LLC, BG Production Company, (PA), LLC, BG Production Company, (WV), LLC and EXCO Resources (PA), LLC, filed herewith.
10.21	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.
10.22	Amendment to Second Amended and Restated Limited Liability Company Agreement of EXCO Resources (PA), LLC, dated October 14, 2014, by and among EXCO Holding (PA), Inc., BG US Production Company, LLC and EXCO Resources (PA), LLC, filed herewith.
10.23	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.
10.24	Amendment to Second Amended and Restated Limited Liability Company Agreement of Appalachia Midstream, LLC (n/k/a EXCO Appalachia Midstream, LLC), dated October 14, 2014, by and among EXCO Holding (PA), Inc., BG US Production Company, LLC and EXCO Appalachia Midstream, LLC, filed herewith.

10.25 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.

10.26 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.

10.27 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.

10.28 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.

10.29 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.

10.30 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.*

10.31 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.

10.32 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.

10.33 Second Amendment to Amended and Restated Credit Agreement, dated as of July 14, 2014, by and among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Form 8-K, dated as of July 14, 2014 and filed on July 18, 2014 and incorporated by reference herein.

10.34 Third Amendment to Amended and Restated Credit Agreement, dated as of October 21, 2014, by and among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated October 21, 2014 and filed on October 27, 2014 and incorporated by reference herein.

10.35 Fourth Amendment to Amended and Restated Credit Agreement, dated as of February 6, 2015, 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 February 6, 2015 and filed on February 12, 2015 and incorporated by reference herein.

10.36 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.

10.37 Amendment No. 1 to Participation Agreement, dated April 17, 2014, among EXCO Operating Company, LP, Admiral A Holding L.P. and Admiral B Holding L.P., filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2014 and filed on July 30, 2014 and incorporated by reference herein.

10.38 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.

10.39 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.

10.40 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.

10.41 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.

10.42 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.

10.43 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.

10.44 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.*

10.45 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.*

10.46 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.*

10.47 Retention Agreement, effective as of September 1, 2014, by and between Richard A. Burnett and EXCO Resources, Inc., filed as an Exhibit to Amendment No. 1 to EXCO's Current Report on Form 8-K/A, dated August 6, 2014 and filed on September 5, 2014 and incorporated by reference herein.*

10.48 Letter Agreement, dated March 28, 2014, by and among EXCO Resources, Inc. and Ares Corporate Opportunities Fund, L.P., 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 Current Report on Form 8-K, dated March 27, 2014 and filed on April 1, 2014 and incorporated by reference herein.

10.49 EXCO Resources, Inc. 2014 Management Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated April 21, 2014 and filed on April 25, 2014 and incorporated by reference herein.*

10.50 Amendment Number One to the EXCO Resources, Inc. Management Incentive Plan, effective as of September 1, 2014, filed as an Exhibit to Amendment No. 1 to EXCO's Current Report on Form 8-K/A, dated August 6, 2014 and filed on September 5, 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 Lee Keeling and Associates, Inc., filed herewith.
23.3	Consent of Netherland, Sewell & Associates, Inc., filed herewith.
23.4	Consent of Ryder Scott Company, L.P., 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	2014 Report of Lee Keeling and Associates, Inc., filed herewith.
99.2	2014 Report of Netherland, Sewell & Associates, Inc., filed herewith.
99.3	2014 Report of Ryder Scott Company, L.P., filed herewith.
99.4	2014 Report of Lee Keeling and Associates, Inc. (OK) 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.

SEC AND NYSE CERTIFICATIONS

The Forms 10-K and 10-K/A, included herein, which were filed by the company with the SEC for the fiscal year ending December 31, 2014, include, as exhibits, the certifications of our principal executive officer and principal financial officer required to be filed with the SEC. Our principal executive officer also filed his 2014 annual certification with the NYSE confirming that the company has complied with the NYSE corporate governance listing standards.

DIRECTORS

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

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

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

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

JEFFREY S. SEROTA [1, 2, 3]
Independent Director

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

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

OFFICERS

HAROLD L. HICKEY
Chief Executive Officer and President

WILLIAM L. BOEING
Vice President, General Counsel
and Secretary

RICHARD A. BURNETT
Vice President, Chief Financial Officer
and Chief Accounting Officer

HAROLD H. JAMESON
Vice President and Chief Operating 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

STEVE L. ESTES
Vice President of Marketing

JOE D. FORD
Vice President
of Human Resources

ROBERT R. GESSNER, JR.
Corporate Controller

RUSSELL D. GRIFFIN
Vice President of Environmental,
Health and Safety

DANIEL W. HIGDON
Vice President of Land

CHRISTOPHER C. PERACCHI
Vice President of Finance
and Investor Relations, and Treasurer

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
Vice President, Finance and
Investor Relations,
and Treasurer
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 2015 Annual Meeting
of Shareholders will be held
on Wednesday, August 5, 2015
at 10:00 a.m. local time at:

EXCO Resources, Inc.
12377 Merit Drive
First Floor Conference Center
Dallas, TX 75251

Stock Transfer Agent
Continental Stock Transfer &
Trust Company
Communications concerning
transfer or exchange requirements,
lost certificates, shareholdings
or changes of address should be
directed to:

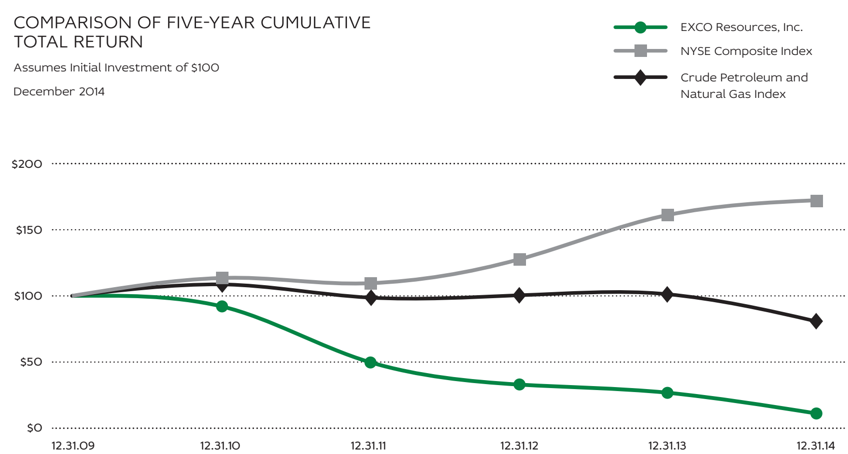
17 Battery Place, 8th Floor
New York, NY 10004
212.509.4000

Number of Common Shareholders
27,326
(As of May 27, 2015)

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN

Assumes Initial Investment of $100

December 2014



The graph to the right compares the cumulative total return (what $100 invested on December 31, 2009 would be worth on December 31, 2014) 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

	12.31.09	12.31.10	12.31.11	12.31.12	12.31.13	12.31.14
EXCO Resources, Inc.	$ 100.00	$ 92.24	$ 50.19	$ 33.25	$ 26.87	$ 11.31
NYSE Composite Index	$ 100.00	$ 113.76	$109.70	$ 127.53	$ 161.20	$ 172.27
Crude Petroleum and Natural Gas Index	$ 100.00	$ 108.66	$ 98.86	$100.44	$ 101.51	$ 81.22

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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