EXCO Resources, Inc.

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EXCO RESOURCES, INC. REPORTS FOURTH QUARTER AND FULL YEAR 2014 RESULTS

DALLAS, TEXAS, February 24, 2015…EXCO Resources, Inc. (NYSE: XCO) ("EXCO") today announced fourth quarter and full year operating and financial results for 2014.

- **Adjusted EBITDA was $81 million for the fourth quarter 2014 and $391 million for the full year 2014.**
- **Production was 31 Bcfe, or 340 Mmcfe per day, for the fourth quarter 2014 and 136 Bcfe, or 372 Mmcfe per day, for the full year 2014.**
- **SEC proved reserves and PV-10 totaled 1.3 Tcfe and $1.5 billion, respectively, for year-end 2014, which included upward revisions of 131 Bcfe primarily due to performance.**
- **Amended credit agreement and implemented cost reduction initiatives to provide operational and financial flexibility.**
- **Drilled 28 gross (9.3 net) and completed 37 gross (11.6 net) operated horizontal shale wells in the fourth quarter 2014 and drilled 122 gross (41.4 net) and completed 98 gross (29.6 net) operated horizontal shale wells for the full year 2014.**

Hal Hickey, EXCO's President and Chief Operating Officer, commented, "Our recent operational achievements and $586 million of liquidity provide us with the framework to lead the company through this challenging commodity cycle. The success of our 2014 drilling program in the Haynesville and Bossier shales of East Texas unlocked additional value through upward revisions of our estimated recoveries and extensions of our proved locations in the area. We have enhanced our completion techniques in the Eagle Ford shale which has yielded our most impressive results to date including initial production rates on certain wells in excess of 900 barrels per day. These operational achievements and other initiatives have further strengthened our ability to generate attractive returns in a low commodity price environment.

"We were proactive in amending our credit agreement to provide us with the liquidity and financial flexibility to persevere through the current market conditions. In order to maximize our cash flows in this commodity price environment, we have negotiated reductions in operating and capital costs 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. Our deep inventory of high-quality drilling opportunities will provide a platform for significant growth when prices recover. We also plan to be opportunistic as we evaluate acquisitions that meet our strategic and financial objectives."

Financial results

GAAP results included net income of $81 million, or $0.30 per diluted share, for the fourth quarter 2014 compared with net income of $42 million, or $0.15 per diluted share, for the third quarter 2014. The increase in net income was primarily due to volatility in commodity prices which resulted in higher unrealized gains on derivative contracts in the fourth quarter 2014. This was partially offset by lower revenues in the fourth quarter 2014 due to a decrease in production and realized commodity prices.

GAAP results included net income of $121 million, or $0.45 per diluted share, for the year ended 2014 compared with net income of $22 million, or $0.10 per diluted share, for the year ended 2013. The increase in net income for the year ended 2014 was primarily due to higher revenues from oil production in the Eagle Ford shale and higher realized natural gas prices. The volatility in commodity prices resulted in higher unrealized gains on derivative contracts. Also, we did not recognize any impairments of our oil and natural gas properties in 2014 compared to $109 million of impairments in 2013. This was partially offset by lower natural gas production year over year.

Adjusted EBITDA for the fourth quarter 2014 was $81 million compared with $94 million for the third quarter 2014. Adjusted EBITDA for the year ended 2014 was $391 million compared with $418 million for the year ended 2013. Adjusted EBITDA is a non-GAAP measure and is computed using earnings before interest, taxes, depletion, depreciation and amortization, and is further adjusted for gains from asset sales, non-cash asset impairments, other non-cash income and expenses, and other items impacting comparability.

Adjusted net income (loss), a non-GAAP measure, was a loss of $0.02 per diluted share for the fourth quarter 2014 compared with income of $0.01 per diluted share for the third quarter 2014. Adjusted net income was $0.06 per diluted share for the year ended 2014 compared with $0.30 per diluted share for the year ended 2013. The non-GAAP adjustments include gains from asset sales, unrealized gains or losses from derivative financial instruments, non-cash asset impairments, items impacting comparability and other items typically not included by securities analysts in published estimates.

Oil, natural gas and natural gas liquid ("NGL") production was 31 Bcfe, or 340 Mmcfe per day, for the fourth quarter 2014 compared with 33 Bcfe, or 358 Mmcfe per day, in the third quarter 2014. Fourth quarter 2014 production from the East Texas/North Louisiana region was 240 Mmcfe per day compared with 242 Mmcfe per day in the third quarter 2014. The slight decrease in production in North Louisiana was primarily due to the timing of wells turned-to-sales, restricted flowback on recent wells turned-to-sales and normal production declines. This was partially offset by an increase in production in the Shelby area of East Texas to 47 Mmcfe per day in the fourth quarter 2014 compared to 24 Mmcfe per day in the third quarter 2014. Fourth quarter production from the South Texas region was 566 Mboe, or 6 Mboe per day, compared with 540 Mboe, or 6 Mboe per day in the third quarter 2014. The increase in production was primarily the result of additional production from wells connected to central production facilities which became operational during the fourth quarter 2014. The fourth quarter 2014 production in the Appalachia region averaged 55 Mmcfe per day compared with 56 Mmcfe per day in the third quarter 2014. Fourth quarter 2014 production from Compass Production Partners, L.P. ("Compass") was 747 Mmcfe prior to the sale on October 31, 2014 compared to 2,271 Mmcfe in the third quarter 2014. Oil, natural gas and NGL production was 136 Bcfe, or 372 Mmcfe per day, for the year ended 2014 compared with 162 Bcfe, or 444 Mmcfe per day, for the year ended 2013. The decrease in year over year production was primarily the result of natural production declines in our East Texas/North Louisiana region and was partially offset by higher oil production from our South Texas region. The production declines in the East Texas/North Louisiana region were primarily the result of reduced development activities within this region compared to periods prior to 2013.

Oil, natural gas and NGL revenues for the fourth quarter 2014 were $128 million compared with $151 million for the third quarter 2014. Our average sales price per Mcfe decreased to $4.08 per Mcfe for the fourth quarter 2014 from $4.58 per Mcfe for the third quarter 2014. Our sales price per Mcfe was negatively impacted by lower market prices for oil and natural gas in the fourth quarter 2014 compared to the third quarter 2014. When the impacts of cash settlements from derivatives are considered, oil, natural gas and NGL revenues were $141 million, or $4.51 per Mcfe for the fourth quarter 2014, compared with $153 million, or $4.65 per Mcfe for the third quarter 2014. Oil, natural gas and NGL revenues for the year ended 2014 were $660 million compared with $634 million for the year ended 2013. The increase in revenues is primarily due to higher natural gas prices and oil production from the Eagle Ford shale. This was partially offset by lower natural gas production. Our average sales price per Mcfe increased to $4.86 per Mcfe for the full year 2014 from $3.92 per Mcfe for the full year 2013. The increase in price was primarily due to higher natural gas prices and a higher percentage of our revenues attributable to oil. When the impacts of cash settlements from derivatives are considered, oil, natural gas and NGL revenues were $641 million, or $4.72 per Mcfe for the full year 2014, compared with $676 million, or $4.18 per Mcfe for the full year 2013.

Direct operating costs were $0.50 per Mcfe for the fourth quarter 2014 compared with $0.43 per Mcfe for the third quarter 2014. The increase was primarily the result of higher direct operating costs per Mcfe associated with activities in the South Texas region related to the connection of wells to central production facilities and other operational initiatives to improve the efficiency of our production equipment. Direct operating costs were $0.47 per Mcfe for the year ended 2014 compared with $0.38 per Mcfe for the year ended 2013. The increase in direct operating costs per Mcfe is primarily attributable to lower production in relation to certain fixed lease operating expenses. This was partially offset by the cost saving initiatives in our South Texas region which reduced direct operating costs per Mcfe in the region to $1.14 per Mcfe for the year ended 2014 from $1.85 per Mcfe for the year ended 2013.

General and administrative expenses were $15 million for the fourth quarter 2014 compared with $14 million for the third quarter 2014. The increase was primarily due to transaction costs associated with the divestiture of Compass and other various legal and consulting services. General and administrative expenses decreased $26 million, or 28%, to $66 million for the year ended 2014 from $92 million for the year ended 2013. The decrease was primarily due to our disciplined cost reduction initiatives including a reduction in our workforce, centralization of certain functions and reduction of discretionary costs.

Cash flow from operations before changes in working capital and other operating items impacting comparability, a non-GAAP measure, was $59 million for the fourth quarter 2014 compared with $72 million for the third quarter 2014. Cash flow from operations before changes in working capital and other operating items impacting comparability was $309 million for the year ended 2014 compared to $345 million for the year ended 2013. During 2014, we primarily used our cash flow from operations to fund our drilling and development programs.

Proved Reserves

Our estimated proved reserves as of December 31, 2014, were 1.3 Tcfe with a PV-10 of $1.5 billion calculated pursuant to SEC pricing rules. For 2014, the SEC reference price was $4.35 per Mmbtu for natural gas and $94.99 per Bbl for oil. Each of the reference prices for oil and natural gas were adjusted for regional differentials. The price used for natural gas liquids was $33.03 per Bbl and was based on trailing 12 month average realized prices.

During 2014, we added 96 Bcfe through discoveries and extensions primarily as a result of our development programs of the Haynesville and Bossier shales in the Shelby area and the Eagle Ford shale. In addition, we added 7 Bcfe of proved reserves through acquisitions which consisted primarily of proved developed producing properties in the Shelby area of East Texas.

Our revisions of previous estimates during 2014 included upward revisions to our proved reserve quantities of 168 Bcfe as a result of an increase in price, which extended the economic life of certain producing properties and resulted in the reclassification of unproved locations to proved undeveloped properties that became economical when using the prices prescribed by the SEC. Our revisions of previous estimates also include upward revisions of 131 Bcfe in proved reserves due to performance and other factors. These upward revisions were primarily in the Shelby area resulting from improved well performance as a result of enhanced completion methods including more proppant, longer laterals and a more restricted flowback. The upward revisions were also in the Appalachia region resulting primarily from a shallower decline of our reserves than previously forecasted.

We divested 127 Bcfe of proved reserves during the year, which consisted primarily of our proportionate share of conventional properties held by Compass. Additionally, we produced 136 Bcfe during the year. The following table presents the details of our changes in proved reserves:

	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 reserve 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 are 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 during 2014 pursuant to the five year development rule established by the SEC.

Our finding and development costs to convert reserves to proved developed reserves were $3.13 per Mcfe during 2014 compared to $1.69 per Mcfe during 2013. The change is representative of an increased focus on oil properties in the Eagle Ford shale compared to the prior year. Our oil properties in the Eagle Ford shale have higher development costs and higher operating margins when calculated on a per Mcfe basis compared to properties focused on natural gas. The increase is also due to high expenditures on wells that were waiting on completion at the end of 2014 that will be converted to proved developed producing properties in 2015. The following table details the components of our 2014 proved developed additions:

	Year Ended			
(dollars in thousands)	**December 31, 2014**		**December 31, 2013**	
Development costs	$	350,438	$	218,353
Exploration costs		5,906		38,579
Total development and exploration (1)	$	356,344	$	256,932
Additions to proved developed reserves (Mmcfe) (2)		113,795		152,007
Finding and development costs per Mcfe	$	3.13	$	1.69

(1) Excludes rig termination fees, field operations capital and other leasehold development costs which are not directly associated with future proved developed reserve additions. In addition, this excludes our proportionate share of Compass's development and exploration costs incurred before the sale of our interest on October 31, 2014.

(2) Our additions to proved developed reserves include both proved undeveloped reserves converted to proved developed reserves, and unproved reserves converted to proved developed reserves. This excludes our proportionate share of Compass's proved reserve additions before the sale of our interest on October 31, 2014.

Recent developments

Compass Production Partners Sale

On October 31, 2014, we closed the sale of our interest in Compass to an affiliate of Harbinger Group, Inc. for $119 million in cash. In addition, our consolidated indebtedness was reduced by our proportionate share of Compass's indebtedness of $83 million upon closing of the sale. We used a portion of the proceeds to reduce indebtedness under the revolving commitment of our credit agreement ("EXCO Resources Credit Agreement"). Our borrowing base under the EXCO Resources Credit Agreement was not affected by this sale since Compass was not a guarantor subsidiary.

Amendment to EXCO Resources Credit Agreement

On February 6, 2015, we amended the EXCO Resources Credit Agreement which resulted in a borrowing base of $725 million. The decrease in our borrowing base was the result of the recent decline in oil and natural gas prices and would have resulted in liquidity of $586 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 2016 and the ratio requirements thereafter were modified. The amendments to the financial covenants will provide us the financial flexibility to selectively develop our asset base while deferring a significant amount of our drilling inventory until commodity prices improve.

Eagle Ford Acquisition Program

We made our first offer for wells drilled under the participation agreement with a joint venture partner ("Participation Agreement") in January 2015. This included seven wells for a total offer price of approximately $15 million. One of the wells met the required return hurdle and the specific well criteria for a committed well as defined in the Participation Agreement ("Committed Well"). The remaining six wells did not meet the Committed Well criteria due to the timing of artificial lift installation, off-set fracturing activity and other factors set forth in the Participation Agreement. These wells are defined as uncertainty wells in the Participation Agreement ("Uncertainty Wells"). Our joint venture partner is only required to accept the offer for the Committed Well of approximately $3 million. Our joint venture partner may accept the offers for the Uncertainty Wells. However, they have the ability to elect to defer the Uncertainty Wells for up to two quarters at which point the wells will be classified as a Committed Well. We expect the offer and acceptance process to be completed and the acquisition to close during the first quarter 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. Any offer well that remains an Uncertainty Well for two consecutive quarters converts to a Committed Well and is included in the offer for Committed Wells for the quarter immediately following such period. As such, the number of wells acquired in 2015 will likely be lower than the 41 wells offered on.

Operations activity and outlook

We spent $107 million on development and exploration activities, drilling 28 gross (9.3 net) operated wells and completing 37 gross (11.6 net) operated wells in the fourth quarter 2014. In addition, we participated in the drilling of 5 gross (1.0 net) wells operated by others ("OBO") during the fourth quarter 2014. We spent $356 million on development and exploration activities, drilling 122 gross (41.4 net) operated wells and completing 98 gross (29.6 net) operated wells for the full year 2014. In addition, we participated in the drilling of 29 gross (5.9 net) OBO wells for the full year 2014. Our development and exploration activities were focused on our Haynesville, Bossier and Eagle Ford shale properties during 2014. Our development activities during the year featured enhanced drilling and completion techniques that improved our well performance while we efficiently managed our capital expenditures which resulted in lower average costs per well. Our capital expenditures also included re-fracture stimulation treatments on 5 gross (2.8 net) mature Haynesville shale wells. We spent $20.3 million on field operations, gathering and water pipelines in 2014 which primarily consisted of the installation of pumping units in South Texas.

Our actual capital expenditures for the fourth quarter 2014 and full year 2014, and 2015 capital budget are presented in the following table.

(in thousands)	Fourth Quarter 2014	Full Year 2014	2015 Budget
Capital expenditures:			
Development capital	$ 106,697	$ 356,344	$ 215,000
Field operations, gathering and water pipelines	3,330	20,256	16,000
Lease purchases and seismic	3,233	10,477	7,000
Corporate and other (1)	8,347	37,198	37,000
Total capital expenditures	$ 121,607	$ 424,275	$ 275,000

(1) Corporate and other primarily consist of capitalized interest and capitalized general and administrative expenses in accordance with U.S. GAAP.

Our board of directors approved a capital budget up to $275 million for 2015, of which $215 million is allocated to development and completion activities. Our developmental 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 of 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 and our development activities are designed to preserve leasehold commitments, fulfill continuous drilling obligations and drill key test wells in the Buda formation. Our capital expenditures 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 in Northeast Pennsylvania.

We expect to fund our 2015 capital budget with cash flow from operations and borrowings under the EXCO Resources Credit Agreement. The 2015 capital budget excludes our offer 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. We will continue to monitor the commodity price environment throughout 2015 and will adjust our capital program as necessary to maximize our returns and manage our cash flow. Our financial position and diverse portfolio of high quality oil and natural gas assets provide us the option to allocate capital to enhance our returns under various commodity price environments. Furthermore, our liquidity and financial flexibility allow us to develop our assets in an optimal time frame based on market conditions.

We are focused on reducing costs throughout the organization 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. The most significant cost reductions realized include fracture stimulation, cementing, production chemical, rentals and fuel costs. We also have implemented initiatives to decrease our general and administrative costs during 2015 including a 15% reduction in our workforce. Our disciplined approach to reducing costs while maintaining the performance, safety and compliance of our operations will help mitigate the impact of lower commodity prices on our financial results.

East Texas/North Louisiana

In the East Texas/North Louisiana region, we operated an average of three drilling rigs in Caddo Parish and DeSoto Parish, Louisiana during the fourth quarter 2014. We drilled 8 gross (4.1 net) operated wells and completed 10 gross (4.4 net) operated wells in the area during the quarter. We have continued to optimize our well design by increasing the amount of proppant used in the hydraulic fracturing process on completions during the quarter. We have also utilized our restricted rate program for the wells turned-to-sales during the fourth quarter 2014 that has proven to be successful in the Shelby area of East Texas. These changes in our well design have demonstrated improved well performance.

In the Shelby area, we completed 4 gross (1.9 net) operated wells during the fourth quarter 2014. Our drilling program during 2014 in this area included enhanced completion methods, longer laterals and a more restricted flowback program. The drilling in this area yielded strong results and resulted in significant upward revisions to our proved reserves based on well performance. The estimated ultimate recoveries ("EUR") for proved undeveloped reserves in this area averaged 1.3 Bcf per 1,000 feet of lateral. This will result in an EUR in excess of 9 Bcf per well based on our planned lateral lengths. The operated wells drilled in the area during 2014 included 5 gross (2.4 net) in the Haynesville shale and 3 gross (1.5 net) in the Bossier shale. We are experiencing strong results from both the Haynesville and Bossier shale wells. We have approximately 250 operated undeveloped locations in this area which provide significant upside potential. The undeveloped locations in this area provide attractive rates of return in the current commodity price environment and will be the primary focus of our 2015 capital program.

We turned-to-sales a test well in the Bossier shale in DeSoto Parish in January 2015 to further assess the potential of the formation. We utilized our technical expertise and recently enhanced completion methods that have proven to be successful in our Haynesville shale development. The results of the well are meeting our expectations and the development of the Bossier shale within DeSoto Parish could result in over 300 additional drilling locations.

We completed our sixth refrac stimulation test on mature Haynesville shale wells in January 2015. These refracs consisted of a re-stimulation of the shale reservoir and the tests included various designs and characteristics of the wells. We are currently analyzing the results of the tests in order to develop our long-term plan for these treatments.

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. We recently secured a contract with our midstream service provider for additional compression services in the Holly area. These additional compression services are expected to begin in the third quarter 2015 based on the project timeline outlined by our midstream service provider. We have seen sustained performance improvement from these initiatives as evidenced by a flattening of our base decline.

South Texas

In the South Texas region, we operated an average of three drilling rigs focused on development of the Eagle Ford shale during the fourth quarter 2014. We drilled 19 gross (4.8 net) operated wells and completed 23 gross (5.2 net) operated wells in the Eagle Ford shale during the quarter. 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. We recently turned-to-sales 13 operated wells in our core area of the Eagle Ford shale with initial production rates that averaged 839 Bbl per day. The strong recent performance from these wells improved our rates of return and lowered our break-even economics to support development in a low commodity price environment.

We drilled our first operated Buda well in January 2015 with a 9,800 foot lateral for an estimated cost of $2.9 million. The well was turned-to-sales in February 2015 and had an initial production rate of 580 Bbl per day. The Buda formation has the potential to add drilling locations to our inventory characterized by low capital intensity with high rates of return. We participated in our first and second non-operated Buda wells during the first quarter 2015 and are encouraged by the results.

We have realized significant improvements in our drilling performance within the South Texas region. This includes improved drilling times per well which are currently averaging 12 days from spud to rig release and we recently drilled a well in 9.5 days. We continue to evaluate updates to our well design including longer laterals and more proppant used in the hydraulic fracturing process. We are implementing initiatives to optimize and increase the efficiency of our production including the installation of pumping units. The pumping units installed to-date have been successful in flattening our base decline.

The first and second central production facilities became operational in the fourth quarter 2014 which allowed us to begin 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. Our third central production facility became operational in the first quarter 2015. A pipeline is currently in the process of being constructed from the central facilities to an oil pipeline in Dilley, Texas which is expected to be operational in the second or third quarter 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.

Appalachia

In the Appalachia region, we remain focused on base production efficiency from our Marcellus shale and conventional assets. We have been able to effectively manage our base production declines as a result of increased automation and surveillance equipment to reduce downtime as well as artificial lift installations. We recently drilled an appraisal well targeting the Marcellus shale in Sullivan County near recent successful results. The recent successful results in the region 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 a significant amount of the prospective acreage is held-by-production.

Financial Data

Our consolidated balance sheets as of December 31, 2014 and December 31, 2013, consolidated statements of operations for the three months ended December 31, 2014, September 30, 2014 and December 31, 2013 and for the years ended December 31, 2014 and 2013 and consolidated statements of cash flows for the years ended December 31, 2014 and 2013, are included on the following pages. We have also included reconciliations of non-GAAP financial measures referred to in this press release.

EXCO will host a conference call on Wednesday, February 25, 2015 at 9:00 a.m. (Central time) to discuss the contents of this release and respond to questions. Please call (800) 309-5788 if you wish to participate, and ask for the EXCO conference call ID#24918636. The conference call will also be webcast on EXCO's website at www.excoresources.com under the Investor Relations tab. Presentation materials related to this release will be posted on EXCO's website prior to the conference call. A digital recording will be available starting two hours after the completion of the conference call until March 11, 2015. Please call (800) 585-8367 and enter conference ID#24918636 to hear the recording. A digital recording of the conference call will also be available on EXCO's website.

Additional information about EXCO Resources, Inc. may be obtained by contacting Chris Peracchi, EXCO's Vice President of Finance and Investor Relations, and Treasurer at EXCO's headquarters, 12377 Merit Drive, Suite 1700, Dallas, TX 75251, telephone number (214) 368-2084, or by visiting EXCO's website at www.excoresources.com. EXCO's SEC filings and press releases can be found under the Investor Relations tab.

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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 a forward-looking statement. When considering our forward-looking statements, keep in mind the cautionary statements and the risk factors included in our Annual Report on Form 10-K for the year ended December 31, 2013, filed with the Securities and Exchange Commission, or the SEC, on February 26, 2014 and after February 25, 2015 our annual Report on Form 10-K for the year ended December 31, 2014, and our other periodic filings with the SEC.

Our revenues, operating results and financial condition substantially depend on prevailing prices for oil and natural gas and the availability of capital from our credit agreement, or the EXCO Resources Credit Agreement. Declines in oil or natural gas prices may have a material adverse effect on our financial condition, liquidity, results of operations, the amount of oil or natural gas that we can produce economically and the ability to fund our operations. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

The SEC permits oil and natural gas companies in filings made with the SEC to disclose proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The SEC permits optional disclosure of "probable" and "possible" reserves in filings with the commission. EXCO may use broader terms to describe additional reserve opportunities such as "potential," "unproved," or "unbooked potential," to describe volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC's guidelines strictly prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable or possible reserves and accordingly are subject to substantially greater risk of actually being realized by the company. While we believe our calculations of unproved drillsites and estimation of unproved reserves have been appropriately risked and are reasonable, such calculations and estimates have not been reviewed by third party engineers or appraisers. Investors are urged to consider closely the disclosure in our Annual Report on Form 10-K for the year ended December 31, 2013, filed with the SEC on February 26, 2014 and after February 25, 2015 our Annual Report on Form 10-K for the year ended December 31, 2014 which is available on our website at www.excoresources.com under the Investor Relations tab.

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

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

EXCO Resources, Inc.
Consolidated Statements of Operations

(in thousands, except per share data)	Three Months Ended December 31, 2014	Three Months Ended September 30, 2014	Three Months Ended December 31, 2013	Year Ended December 31, 2014	Year Ended December 31, 2013
Revenues:	(Unaudited)	(Unaudited)	(Unaudited)		
Total revenues	$ 127,789	$ 151,042	$ 180,440	$ 660,269	$ 634,309
Costs and expenses:					
Oil and natural gas operating costs	15,754	14,099	18,571	64,467	61,277
Production and ad valorem taxes	6,908	7,978	6,668	29,859	21,971
Gathering and transportation	25,101	25,822	26,096	101,574	100,645
Depletion, depreciation and amortization	62,128	64,913	82,580	263,569	245,775
Impairment of oil and natural gas properties	—	—	97,839	—	108,546
Accretion of discount on asset retirement obligations	605	709	649	2,690	2,514
General and administrative	15,019	14,059	25,383	65,920	91,878
(Gain) loss on divestitures and other operating items	(1,067)	663	1,985	5,315	(177,518)
Total costs and expenses	124,448	128,243	259,771	533,394	455,088
Operating income (loss)	3,341	22,799	(79,331)	126,875	179,221
Other income (expense):					
Interest expense, net	(24,178)	(23,974)	(30,818)	(94,284)	(102,589)
Gain (loss) on derivative financial instruments	102,561	42,844	(19,495)	87,665	(320)
Other income (expense)	65	53	(1,168)	241	(828)
Equity income (loss)	(376)	(153)	7,949	172	(53,280)
Total other income (expense)	78,072	18,770	(43,532)	(6,206)	(157,017)
Income (loss) before income taxes	81,413	41,569	(122,863)	120,669	22,204
Income tax expense	—	—	—	—	—
Net income (loss)	$ 81,413	$ 41,569	$ (122,863)	$ 120,669	$ 22,204
Earnings (loss) per common share:					
Basic:					
Net income (loss)	$ 0.30	$ 0.15	$ (0.57)	$ 0.45	$ 0.10
Weighted average common shares outstanding	271,053	270,631	215,410	268,258	215,011
Diluted:					
Net income (loss)	$ 0.30	$ 0.15	$ (0.57)	$ 0.45	$ 0.10
Weighted average common shares and common share equivalents outstanding	271,053	272,066	215,410	268,376	230,912

EXCO Resources, Inc.
Consolidated Statements of Cash Flows

(in thousands)	Year Ended December 31, 2014	2013
Operating Activities:		
Net income	$ 120,669	$ 22,204
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation and amortization	263,569	245,775
Share-based compensation expense	4,962	10,748
Accretion of discount on asset retirement obligations	2,690	2,514
Impairment of oil and natural gas properties	—	108,546
(Income) loss from equity investments	(172)	53,280
(Gain) loss on derivative financial instruments	(87,665)	320
Cash settlements (payments) of derivative financial instruments	(18,991)	42,119
Amortization of deferred financing costs and discount on debt issuance	12,055	29,624
Gain on divestitures and other non-operating items	(17)	(185,163)
Effect of changes in:		
Accounts receivable	52,007	(46,176)
Other current assets	(2,609)	9,627
Accounts payable and other current liabilities	15,595	57,216
Net cash provided by operating activities	362,093	350,634
Investing Activities:		
Additions to oil and natural gas properties, gathering assets and equipment	(391,776)	(320,538)
Property acquisitions	(10,790)	(976,714)
Proceeds from disposition of property and equipment	187,655	749,628
Restricted cash	(3,400)	49,515
Net changes in advances to joint ventures	(5,026)	10,645
Equity method investments	1,749	236,289
Other	—	(1,303)
Net cash used in investing activities	(221,588)	(252,478)
Financing Activities:		
Borrowings under credit agreements	100,000	1,004,523
Repayments under credit agreements	(964,970)	(1,022,785)
Proceeds received from issuance of 2022 Notes	500,000	—
Proceeds from issuance of common shares, net	271,773	1,712
Payment of common share dividends	(41,060)	(43,214)
Deferred financing costs and other	(10,290)	(33,553)
Payments of common shares repurchased	(136)	—
Net cash used in financing activities	(144,683)	(93,317)
Net increase (decrease) in cash	(4,178)	4,839
Cash at beginning of period	50,483	45,644
Cash at end of period	$ 46,305	$ 50,483
Supplemental Cash Flow Information:		
Cash interest payments	$ 91,735	$ 88,936
Income tax payments	—	—
Supplemental non-cash investing and financing activities:		
Capitalized share-based compensation	$ 5,498	$ 7,288
Capitalized interest	20,060	18,729
Issuance of common stock for director services	235	93
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

EXCO Resources, Inc.
Consolidated EBITDA
And Adjusted EBITDA Reconciliations and Statement of Cash Flow Data
(Unaudited)

	Three Months Ended			Year Ended	
(in thousands)	**December 31, 2014**	**September 30, 2014**	**December 31, 2013**	**December 31, 2014**	**December 31, 2013**
Net income (loss)	$ 81,413	$ 41,569	$ (122,863)	$ 120,669	$ 22,204
Interest expense	24,178	23,974	30,818	94,284	102,589
Income tax expense	—	—	—	—	—
Depletion, depreciation and amortization	62,128	64,913	82,580	263,569	245,775
EBITDA(1)	$ 167,719	$ 130,456	$ (9,465)	$ 478,522	$ 370,568
Accretion of discount on asset retirement obligations	605	709	649	2,690	2,514
Impairment of oil and natural gas properties	—	—	97,839	—	108,546
(Gain) loss on divestitures and other items impacting comparability	714	1,747	8,143	11,836	(170,550)
Equity (income) loss	376	153	(7,949)	(172)	53,280
Net (gains) losses on derivative financial instruments	(102,561)	(42,844)	19,495	(87,665)	320
Cash settlements (payments) on derivative financial instruments	13,196	2,282	13,703	(18,991)	42,119
Share based compensation expense	592	1,118	1,255	4,962	10,748
Adjusted EBITDA (1)	$ 80,641	$ 93,621	$ 123,670	$ 391,182	$ 417,545
Interest expense	(24,178)	(23,974)	(30,818)	(94,284)	(102,589)
Income tax expense	—	—	—	—	—
Amortization of deferred financing costs and discount	2,164	2,194	7,184	12,055	29,624
Other operating items impacting comparability	(723)	(1,755)	(6,840)	(11,853)	(14,613)
Changes in working capital	(54,176)	20,157	34,067	64,993	20,667
Net cash provided by operating activities	$ 3,728	$ 90,243	$ 127,263	$ 362,093	$ 350,634

EXCO Resources, Inc.
Consolidated EBITDA
And Adjusted EBITDA Reconciliations and Statement of Cash Flow Data
(Unaudited)

	Three Months Ended			Year Ended	
(in thousands)	December 31, 2014	September 30, 2014	December 31, 2013	December 31, 2014	December 31, 2013
Statement of cash flow data:					
Cash flow provided by (used in):					
Operating activities	$ 3,728	$ 90,243	$ 127,263	$ 362,093	$ 350,634
Investing activities	15,420	(112,065)	146,114	(221,588)	(252,478)
Financing activities	(20,793)	23,894	(256,387)	(144,683)	(93,317)
Other financial and operating data:					
EBITDA(1)	$ 167,719	$ 130,456	$ (9,465)	$ 478,522	$ 370,568
Adjusted EBITDA(1)	80,641	93,621	123,670	391,182	417,545

(1) Earnings before interest, taxes, depreciation, depletion and amortization, or "EBITDA" represents net income adjusted to exclude interest expense, income taxes and depletion, depreciation and amortization. "Adjusted EBITDA" represents EBITDA adjusted to exclude other operating items impacting comparability, accretion of discount on asset retirement obligations, non-cash changes in the fair value of derivatives, non-cash impairments of assets, stock-based compensation and income or losses from equity method investments. We have presented EBITDA and Adjusted EBITDA because they are a widely used measure by investors, analysts and rating agencies for valuations, peer comparisons and investment recommendations. In addition, similar measures are used in covenant calculations required under our credit agreement, the indenture governing our 7.5% senior notes due September 15, 2018 ("2018 Notes"), and the indenture governing our 8.5% senior notes due April 15, 2022 ("2022 Notes"). Compliance with the liquidity and debt incurrence covenants included in these agreements is considered material to us. Our computations of EBITDA and Adjusted EBITDA may differ from computations of similarly titled measures of other companies due to differences in the inclusion or exclusion of items in our computations as compared to those of others. EBITDA and Adjusted EBITDA are measures that are not prescribed by GAAP. EBITDA and Adjusted EBITDA specifically exclude changes in working capital, capital expenditures and other items that are set forth on a cash flow statement presentation of a company's operating, investing and financing activities. As such, we encourage investors not to use these measures as substitutes for the determination of net income, net cash provided by operating activities or other similar GAAP measures. The calculation of EBITDA and Adjusted EBITDA as presented herein differ in certain respects from the calculation of comparable measures in the EXCO Resources Credit Agreement, the indenture governing our 2018 Notes and the indenture governing our 2022 Notes.

EXCO Resources, Inc.
Consolidated Adjusted Net Income (Loss) and Adjusted Net Income (Loss) Reconciliations
(Unaudited)

	Three Months Ended						Year Ended			
	December 31, 2014		September 30, 2014		December 31, 2013		December 31, 2014		December 31, 2013	
(in thousands, except per share amounts)	Amount	Per share	Amount	Per share	Amount	Per share	Amount	Per share	Amount	Per share
Net income (loss), GAAP	$ 81,413		$ 41,569		$(122,863)		$ 120,669		$ 22,204	
Adjustments:										
Net (gains) losses on derivatives	(102,561)		(42,844)		19,495		(87,665)		320	
Cash settlements (payments) on derivatives	13,196		2,282		13,703		(18,991)		42,119	
Impairment of oil and natural gas properties	—		—		97,839		—		108,546	
Adjustments included in equity (income) loss	296		—		(4,736)		(1,453)		90,214	
(Gain) loss on divestitures and other items impacting comparability	714		1,747		8,143		11,836		(170,550)	
Deferred finance cost amortization acceleration	—		—		4,256		3,471		20,974	
Income taxes on above adjustments (1)	35,342		15,526		(55,480)		37,121		(36,649)	
Adjustment to deferred tax asset valuation allowance (2)	(32,565)		(16,628)		49,145		(48,268)		(8,882)	
Total adjustments, net of taxes	(85,578)		(39,917)		132,365		(103,949)		46,092	
Adjusted net income (loss)	$ (4,165)		$ 1,652		$ 9,502		$ 16,720		$ 68,296	
Net income (loss), GAAP (3)	$ 81,413	$ 0.30	$ 41,569	$ 0.15	$(122,863)	$(0.57)	$ 120,669	$ 0.45	$ 22,204	$ 0.10
Adjustments shown above (3)	(85,578)	(0.32)	(39,917)	(0.14)	132,365	0.61	(103,949)	(0.39)	46,092	0.20
Dilution attributable to share-based payments and rights outstanding (4)	—	—	—	—	—	—	—	—	—	—
Adjusted net income (loss)	$ (4,165)	$(0.02)	$ 1,652	$ 0.01	$ 9,502	$ 0.04	$ 16,720	$ 0.06	$ 68,296	$ 0.30
Common stock and equivalents used for earnings per share (EPS):										
Weighted average common shares outstanding	271,053		270,631		215,410		268,258		215,011	
Dilutive stock options	—		—		—		—		—	
Dilutive restricted shares	—		1,435		327		118		420	
Dilutive subscription rights	—		—		7,118		—		15,481	
Shares used to compute diluted EPS for adjusted net income	271,053		272,066		222,855		268,376		230,912	

(1) The assumed income tax rate is 40% for all periods.
(2) Deferred tax valuation allowance has been adjusted to reflect the assumed income tax rate of 40% for all periods.
(3) Per share amounts are based on weighted average number of common shares outstanding.
(4) Represents dilution per share attributable to common share equivalents from in-the-money stock options, dilutive restricted shares and subscription rights calculated in accordance with the treasury stock method.

EXCO Resources, Inc.
Consolidated Cash Flow from Operations before Working Capital Changes and Other Operating Items Impacting Comparability and Reconciliations
(Unaudited)

	Three Months Ended			Year Ended	
(in thousands)	December 31, 2014	September 30, 2014	December 31, 2013	December 31, 2014	December 31, 2013
Cash flow from operations, GAAP	$ 3,728	$ 90,243	$ 127,263	$ 362,093	$ 350,634
Net change in working capital	54,176	(20,157)	(34,067)	(64,993)	(20,667)
Other operating items impacting comparability	714	1,747	6,840	11,836	14,613
Cash flow from operations before changes in working capital and other operating items impacting comparability, non-GAAP measure (1)	$ 58,618	$ 71,833	$ 100,036	$ 308,936	$ 344,580

(1) Cash flow from operations before working capital changes and other operating items impacting comparability is presented because management believes it is a useful financial indicator for companies in our industry. This non-GAAP disclosure is widely accepted as a measure of an oil and natural gas company's ability to generate cash used to fund development and acquisition activities and service debt or pay dividends. Cash flow from operations before changes in working capital is not a measure of financial performance pursuant to GAAP and should not be used as an alternative to cash flows from operating, investing, or financing activities. Other operating items impacting comparability have been excluded as they do not reflect our on-going operating activities.

EXCO Resources, Inc.
Summary of Operating Data
(Unaudited)

	Three Months Ended		%	Three Months Ended		%	Year Ended		%
	December 31, 2014	September 30, 2014	Change	December 31, 2014	December 31, 2013	Change	December 31, 2014	December 31, 2013	Change
Production:									
Oil (Mbbls)	527	537	(2)%	527	653	(19)%	2,236	1,188	88 %
Natural gas (Mmcf)	27,893	29,359	(5)%	27,893	36,765	(24)%	120,980	153,321	(21)%
Natural gas liquids (Mbbls)	38	62	(39)%	38	65	(42)%	224	243	(8)%
Total production (Mmcfe) (1)	31,283	32,953	(5)%	31,283	41,073	(24)%	135,740	161,907	(16)%
Average daily production (Mmcfe)	340	358	(5)%	340	446	(24)%	372	444	(16)%
Average sales price (before cash settlements of derivative financial instruments):									
Oil (per Bbl)	$ 70.56	$ 94.50	(25)%	$ 70.56	$ 90.79	(22)%	$ 87.80	$ 93.80	(6)%
Natural gas (per Mcf)	3.23	3.36	(4)%	3.23	3.23	— %	3.79	3.35	13 %
Natural gas liquids (per Bbl)	10.66	27.44	(61)%	10.66	35.51	(70)%	26.82	35.23	(24)%
Natural gas equivalent (per Mcfe)	4.08	4.58	(11)%	4.08	4.39	(7)%	4.86	3.92	24 %
Costs and expenses (per Mcfe):									
Oil and natural gas operating costs	$ 0.50	$ 0.43	16 %	$ 0.50	$ 0.45	11 %	$ 0.47	$ 0.38	24 %
Production and ad valorem taxes	0.22	0.24	(8)%	0.22	0.16	38 %	0.22	0.14	57 %
Gathering and transportation	0.80	0.78	3 %	0.80	0.64	25 %	0.75	0.62	21 %
Depletion	1.96	1.93	2 %	1.96	1.97	(1)%	1.90	1.47	29 %
Depreciation and amortization	0.03	0.04	(25)%	0.03	0.04	(25)%	0.04	0.05	(20)%

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