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EXCO RESOURCES, INC. REPORTS SECOND QUARTER 2011 RESULTS

DALLAS, TEXAS, August 2, 2011…EXCO Resources, Inc. (NYSE: XCO) ("EXCO") today announced second quarter results for 2011.

Our second quarter 2011 operating and financial results reflect our continued success in the Haynesville/Bossier shale area and further expansion and refinement of opportunities in our Marcellus shale operations. During the quarter, we closed an acquisition of mineral interests, land and other assets in our core DeSoto Parish area and continued with our 27 operated drilling rig program consisting of 22 rigs in the Haynesville/Bossier shale, three in Appalachia and two in our Permian area. Our production and cash flows are increasing and our capital expenditure program can be executed with cash flow and available borrowing capacity from our credit agreement. Our financial results for the second quarter 2011 follow.

- Adjusted net earnings, a non-GAAP measure adjusting for non-cash gains and losses from derivative financial instruments (derivatives), gains from early termination of derivatives, gains on divestitures, costs we have incurred in connection with the special committee's review of strategic alternatives and items typically not included by securities analysts in published estimates, were $0.18 per share for the second quarter 2011 compared to $0.13 per share for the first quarter 2011 and $0.11 per share for the second quarter 2010.

- GAAP results were net income of $0.38 per diluted share for the second quarter 2011 compared with net income of $0.10 per diluted share for the first quarter 2011. Net income was $2.62 per diluted share for the second quarter 2010, reflecting a $575 million pre-tax gain ($2.67 per diluted share) arising from our June 1, 2010 Appalachia JV.

- Oil and natural gas production was 46 Bcfe, or 500 Mmcfe per day, for the second quarter 2011 compared with 37 Bcfe, or 408 Mmcfe per day, in the first quarter 2011. Production was 27 Bcfe, or 292 Mmcfe per day, in the second quarter 2010. The increase in the year-over-year quarterly production is primarily attributable to increased production volumes in our Haynesville/Bossier shale play, where second quarter 2011 volumes were 32 Bcfe (357 Mmcfe per day) compared with 12 Bcfe (128 Mmcfe per day) in the second quarter 2010, an increase of 179%. The increased production during the second quarter was reduced by approximately 23 Mmcf per day as a result of a May

28, 2011 incident at a TGGT treating facility which resulted in curtailment of certain North Louisiana production volumes. We expect that certain volumes will be curtailed through the end of the third quarter 2011.

- Oil and natural gas revenues for the second quarter 2011 were $207 million compared with $161 million for the first quarter 2011. The second quarter 2010 oil and natural gas revenues were $118 million. The higher year-over-year revenues reflect an increase in the average sales price per Mcfe of 2% from the prior year quarter, coupled with a 71% increase in production. When the impacts of cash settlements from our oil and natural gas derivatives are considered, oil and natural gas revenues were $230 million for the second quarter 2011 compared with $188 million for the first quarter 2011 and $165 million for the second quarter 2010.

- Oil and natural gas operating costs for the second quarter 2011 were $0.45 per Mcfe compared to $0.85 per Mcfe for the second quarter 2010. This 47% reduction in per unit operating costs reflects the impact of lower cost volumes attributable to our Haynesville/Bossier shale development.

- Adjusted earnings before interest, taxes, depreciation, depletion and amortization and other non-cash income and expense items (adjusted EBITDA, a non-GAAP measure) for the second quarter 2011 was $164 million compared with adjusted EBITDA of $126 million in the first quarter 2011 and $99 million in the second quarter 2010.

Douglas H. Miller, EXCO's Chief Executive Officer commented "Our exceptional results for the quarter highlight the quality of our asset base and employees. Despite curtailed production during the quarter resulting from the TGGT treating facility incident, our daily production grew by 71% year-over-year and 23% from the first quarter of 2011. We continue to see strong Haynesville shale results in our DeSoto Parish position where we are in full manufacturing mode. In our Shelby area, we realized IP's of over 28 Mmcf per day in the Haynesville shale and 25 Mmcf per day in the Bossier shale as we further delineate that acreage. Our results in the Marcellus shale continue to improve and we expect to increase our level of activity as a result. We are focused on managing both capital costs and operating expenses across our portfolio, in addition to increasing our positions in both the Haynesville/Bossier and Marcellus shales. Including cash on hand and our unused borrowing base, we have approximately $777 million of liquidity to fund our capital program and acreage acquisition efforts. With our extensive drilling inventory, we continue to expect substantial production growth for the remainder of 2011 and in future years while continuing to manage our balance sheet."

Net income

Our reported net income shown below, a GAAP measure, includes certain items not typically included by securities analysts in their published estimates of financial results. The following table provides a reconciliation of our net income to non-GAAP measures of adjusted net income:

(in thousands, except per share amounts)	Three months ended June 30, 2011 Amount	Per share	June 30, 2010 Amount	Per share	Six months ended June 30, 2011 Amount	Per share	June 30, 2010 Amount	Per share
Net income, GAAP	$ 82,362		$ 564,313		$ 104,303		$ 679,881	
Adjustments:								
Non-cash mark-to-market (gains) losses on derivative financial instrum								
before taxes	(20,056)		45,831		3,458		21,711	
Gain on divestitures	-		(574,878)		-		(574,878)	
Gains from early termination of derivative financial instruments	-		-		-		(37,936)	
Non-recurring other operating items (1)	2,980		-		5,955		-	
Income taxes on above adjustments (2)	6,830		211,619		(3,765)		236,441	
Adjustment to deferred tax asset valuation allowance (3)	(32,944)		(223,054)		(41,721)		(269,281)	
Total adjustments, net of taxes	(43,190)		(540,482)		(36,073)		(623,943)	
Adjusted net income	$ 39,172		$ 23,831		$ 68,230		$ 55,938	
Net income, GAAP (4)	$ 82,362	$ 0.39	$ 564,313	$ 2.66	$ 104,303	$ 0.49	$ 679,881	$ 3.20
Adjustments shown above (4)	(43,190)	(0.20)	(540,482)	(2.54)	(36,073)	(0.17)	(623,943)	(2.94)
Dilution attributable to stock options (5)	-	(0.01)	-	(0.01)	-	(0.01)	-	-
Adjusted net income	$ 39,172	$ 0.18	$ 23,831	$ 0.11	$ 68,230	$ 0.31	$ 55,938	$ 0.26
Common stock and equivalents used for earnings per share (EPS):								
Weighted average common shares outstanding	213,888		212,497		213,710		212,293	
Dilutive stock options	3,625		3,001		3,603		3,227	
Shares used to compute diluted EPS for adjusted net income	217,513		215,498		217,313		215,520	

(1) Costs primarily associated with the special committee's review of strategic alternatives.
(2) The assumed income tax rate is 40% for all periods.
(3) Deferred tax valuation allowance has been adjusted to reflect the assumed income tax rate of 40% for all periods.
(4) Per share amounts are based on weighted average number of common shares outstanding.
(5) Represents dilution per share attributable to common stock equivalents from in-the-money stock options.

Cash flow and financing transactions

Our cash flow from operations before working capital changes, a non-GAAP measure, was $152 million for the second quarter 2011. We use our cash flow, credit agreement and proceeds from selected divestitures to fund drilling and development programs.

(in thousands)	Three months ended June 30, 2011	2010	Six months ended June 30, 2011	2010
Cash flow from operations, GAAP	$ 148,960	$ 90,550	$ 228,033	$ 181,853
Net change in working capital	372	(6,443)	31,611	38,946
Gains from early termination of derivative financial instruments	-	-	-	(37,936)
Non-recurring other operating items	2,980	-	5,955	-
Settlements of derivative financial instruments with a financing element	-	-	-	(907)
Cash flow from operations before changes in working capital, non-GAAP measure (1)	$ 152,312	$ 84,107	$ 265,599	$ 181,956

(1) Cash flow from operations before working capital changes, non-recurring other operating items, early termination of derivatives and adjustments for settlements of derivative financial instruments with a financing element are 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. Operating cash flow 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. We have also elected to exclude the adjustment for derivative financial instruments with a financing element as this adjustment simply reclassifies settlements from operating cash flows to financing activities. Management believes these settlements should be included in this non-GAAP measure to conform to the intended measure of our ability to generate cash to fund operations and development activities. Non-recurring other operating items and early termination of derivatives have been excluded as they do not reflect our on-going operating activities.

Redetermination of borrowing base

On April 1, 2011, the lenders under our revolving credit agreement completed their regular semi-annual redetermination of the borrowing base, resulting in an increase of the borrowing base from $1.0 billion to $1.5 billion. In addition, the interest rate under the credit agreement was reduced by 50 basis points (bps) and the maturity date was extended from April 30, 2014 to April 1, 2016. The next redetermination of the borrowing base is scheduled to occur on October 1, 2011.

As of July 27, 2011, $852 million was drawn under our credit agreement and we had $138 million of cash, which includes $106 million of restricted cash. Our available borrowing under our credit agreement as of July 27, 2011, including cash and restricted cash on hand was $777 million.

Operations activity and outlook

We spent $241 million on development and exploitation activities, drilling and completing 71 gross (40.6 net) operated wells in the second quarter 2011, compared with 65 gross (36.1 net) operated wells during the first quarter 2011. In addition, we participated in 20 gross (0.8 net) wells operated by others (OBO) during the second quarter 2011. We had an overall drilling success rate of 99% for the second quarter 2011. Our total capital expenditures, including leasing and net of acreage reimbursements from BG Group, were approximately $260 million in the second quarter 2011. We are continuing efforts to opportunistically acquire additional leasehold in our core shale areas.

Our projected capital spending for 2011 is presented in the following table:

(in thousands)	1Q 2011 actuals	2Q 2011 actuals	July - December 2011 capital forecast	Total 2011 capital forecast
Capital expenditures:				
Development capital expenditures	$ 198,288	$ 240,925	$ 431,678	$ 870,891
Lease purchases (1)	24,546	80	13,760	38,386
Seismic	4,447	979	7,512	12,938
Water pipelines and gas gathering	812	1,272	7,701	9,785
Corporate and other	17,518	17,182	30,300	65,000
Capital expenditures before acquisitions	$ 245,611	$ 260,438	$ 490,951	$ 997,000

(1) Net of acreage reimbursements from BG Group totaling $20.7 million in the first half of 2011, and $4.4 million of future reimbursements.

In addition to our capital program, we closed on $113 million, net to EXCO, of acquisitions during the second quarter 2011.

Haynesville/Bossier Shale

Our horizontal Haynesville shale development program continues to yield outstanding results. As of July 25, 2011, our Haynesville/Bossier operated production was 1,173 Mmcf per day gross (365 Mmcf per day net) and with the addition of our OBO wells, we had 391 Mmcf per day of net production. Our development program in DeSoto Parish, Louisiana is focused on manufacturing on 80-acre spacing. Our program in San Augustine and Nacogdoches Counties, Texas is focused on delineation and testing of our acreage. During 2011, we plan to drill 241 gross (70.1 net) wells in the Haynesville/Bossier shale play in East Texas/North Louisiana. Of these 241 wells, 171 gross wells are operated by EXCO.

We drilled and completed 47 gross (20.4 net) operated horizontal Haynesville and Bossier wells and participated in 20 gross (0.8 net) OBO Haynesville horizontal wells during the second quarter of 2011. We utilized 22 operated rigs and spud 42 operated horizontal wells. In addition to our operated rig count, we typically have 3-6 OBO rigs drilling in the play. During the quarter, 11 OBO wells were spud. We currently have 232 operated horizontal wells and 123 OBO horizontal wells flowing to sales.

The average initial production rate ("IP") during the quarter from all of our operated Haynesville horizontal wells in DeSoto Parish was 18 Mmcf per day on a managed drawdown/restricted choke program. Our manufacturing approach for simultaneous drilling followed by simultaneous completions by unit is being successfully implemented. We currently have 15 units fully drilled, completed and flowing to sales on 80-acre spacing and expect to have 25 units fully developed by year end. This high level of sustained performance in our 80-acre development program underscores the quality and consistency of our shale assets. We have a strong focus on the capital efficiencies of our drilling and completion programs. The design changes and manufacturing efficiency gains in both the drilling phase and the completion phase of our wells should result in an overall well cost reduction of approximately 7% compared to our actual costs incurred in the first half of 2011. These improvements are the result of more efficient pad and road utilization and construction processes, design changes with drill bit technology resulting in higher rates of penetration and a more efficient completion design and implementation process, among others.

We acquired the assets in our Shelby area in May 2010. At the time of acquisition, the area total production rate was 34 Mmcf per day gross from eight operated wells. Our Shelby area is currently producing 222 Mmcf per day gross from a total of 39 operated wells. Results from our testing and delineation program in our Shelby area are encouraging. In the quarter we completed four wells in the deeper part of the play in Nacogdoches County, Texas with average IP rates of 29 Mmcf per day with average flowing pressures of 9,566 psi on 28/64ths chokes. The wells in this area are just over 19,400 feet measured depth with an average completed lateral length of 4,600 feet. These wells are performing above our original expectations. We drilled and completed our first horizontal Middle Bossier test well in San Augustine County during the first quarter 2011 with an IP rate of 26 Mmcf per day from a 16 stage fracture stimulation treatment. The Middle Bossier performance is also above our original expectations. We currently have two Middle Bossier test wells drilling and a total of eight operated rigs running in the Shelby area.

Marcellus Shale

We are implementing a development program within our recently acquired acreage in northeast Pennsylvania. We are also implementing an appraisal program across much of our other acreage, primarily in central Pennsylvania. We spud seven new operated wells and drilled and completed 6 gross (2.7 net) operated wells during the second quarter 2011 in the Marcellus shale. The IP rates of these wells ranged from 2 Mmcf per day to over 5 Mmcf per day from lateral lengths between 3,200 feet and 5,000 feet. In all of EXCO's operating areas, we disclose IP as the peak 24-hour production rate during our first few days of flowback. However, in Appalachia, we have wells that realize peak production rates approximately one to two months after initial production, as the wells unload water, flowback is managed and tubing is installed. In certain areas, we have realized an average rate increase of 50-75% between the first seven days of production and the peak production rate. We continue to evaluate reservoir performance to optimize our development plans.

We plan to drill 49 gross (16.0 net) operated wells in the Marcellus shale play in our Appalachia region during 2011. Of the 49 wells, 42 gross (12.8 net) will be development wells and 7 gross (3.2 net) will be appraisal wells. This drilling will be within the Appalachia JV area, so our net drilling dollars are reduced by the effect of the carry we receive from BG Group. Approximately $98 million of the carry remains available to us from BG Group as of June 30, 2011. We expect that the remaining carry amount will be used by the end of 2011. We are currently drilling with three operated rigs and we plan to exit 2011 with 4-5 operated drilling rigs in Appalachia.

Permian

We drilled and completed 18 gross (17.5 net) wells in our Permian area Canyon Sand field during the second quarter 2011 with 95% drilling success as one of our wells was a dry hole. We continue to run two operated rigs in the Canyon Sand field and plan to drill 72 gross (69.8 net) wells in 2011. Oil production at Sugg Ranch has increased by 17% in the second quarter of 2011 as compared to the second quarter of 2010, and economics for this drilling activity typically have rates-of-return in excess of 50%.

Midstream

Through our jointly held midstream company, TGGT, we continue our major infrastructure expansion efforts in our Shelby Trough area of east Texas in order to meet the expected throughput volume increase. We are also continuing to develop our gathering and treating capacity in the DeSoto Parish area of northwest Louisiana. Total throughput for TGGT averaged approximately 1.4 Bcf per day for the second quarter of 2011 compared with total average throughput of 1.2 Bcf per day in the first quarter 2011. Despite the volumetric reductions from the May 28, 2011 incident discussed below, our current throughput as of July 25, 2011 was approximately 1.5 Bcf per day.

On May 28, 2011, an incident occurred at a TGGT amine treating facility in northwest Red River Parish, Louisiana resulting in an immediate shut-down of the facility. As a precautionary measure, TGGT also shut down another amine treating facility located in DeSoto Parish with similar specifications. While TGGT has an ongoing investigation into causes of the incident, they have ordered temporary treating units and expect resumption of treating capacity during the third quarter of 2011, with a total resumption of treating facilities during the fourth quarter of 2011. The estimated second quarter 2011 impact to TGGT resulting from this incident was a $4 million net decrease to their operating income and the anticipated impact for the remainder of the year is a $10 million decrease in their operating income. In addition, TGGT recorded an impairment charge to the damaged facility of approximately $12 million in the second quarter of 2011. The majority of this charge is expected to be offset in the future by insurance proceeds.

Financial Data

Our consolidated balance sheets as of June 30, 2011 and December 31, 2010 and consolidated statements of operations for the three and six months ended June 30, 2011 and 2010, and consolidated statements of cash flows for the six months ended June 30, 2011 and 2010, are included on the following pages. We have also included reconciliations of non-GAAP financial measures referred to in this press release which have not been previously reconciled.

EXCO will host a conference call on Wednesday, August 3, 2011 at 9:00 a.m. (Dallas 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# 83127029. 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 on Tuesday, August 2, 2011, after market close.

A digital recording will be available starting two hours after the completion of the conference call until 11:59 p.m., August 17, 2011. Please call (855) 859-2056 and enter conference ID# 83127029 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 EXCO's Chairman, Douglas H. Miller, or its President, Stephen F. Smith, 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. You are cautioned not to place undue reliance on a forward-looking statement. When considering our forward-looking statements, keep in mind the risk factors and other cautionary statements in this presentation, and the risk factors included in the Annual Report on Form 10-K, as amended, for the year ended December 31, 2010, and our other periodic filings with the SEC.

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

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. Beginning with reserves reported for the year ended December 31, 2009, the SEC permits optional disclosure of "probable" and "possible" reserves in its filings with the SEC. 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 being actually 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, as amended, for the year ended December 31, 2010, which is available on our website at www.excoresources.com under the Investor Relations tab.

EXCO Resources, Inc.
Consolidated balance sheet

(in thousands)	June 30, 2011 (Unaudited)	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 65,186	$ 44,229
Restricted cash	149,215	161,717
Accounts receivable, net:		
Oil and natural gas	123,302	80,740
Joint interest	105,194	104,358
Interest and other	25,973	35,594
Inventory	8,196	7,876
Derivative financial instruments	69,187	73,176
Other	17,872	12,770
Total current assets	564,125	520,460
Equity investments	273,632	379,001
Oil and natural gas properties (full cost accounting method):		
Unproved oil and natural gas properties and development costs not being amortized	783,621	599,409
Proved developed and undeveloped oil and natural gas properties	3,038,647	2,370,962
Accumulated depletion	(1,456,225)	(1,312,216)
Oil and natural gas properties, net	2,366,043	1,658,155
Gas gathering assets	160,111	157,929
Accumulated depreciation and amortization	(29,114)	(24,772)
Gas gathering assets, net	130,997	133,157
Office, field, and other equipment, net	43,582	43,149
Deferred financing costs, net	33,822	30,704
Derivative financial instruments	21,992	23,722
Goodwill	218,256	218,256
Deposits on acquisitions	-	464,151
Other assets	6,665	6,665
Total assets	$ 3,659,114	$ 3,477,420

EXCO Resources, Inc.
Consolidated balance sheet

(in thousands, except per share and share data)	June 30, 2011 (Unaudited)	December 31, 2010
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 157,117	$ 152,999
Revenues and royalties payable	178,151	108,830
Accrued interest payable	17,943	18,983
Current portion of asset retirement obligations	1,279	900
Income taxes payable	-	211
Derivative financial instruments	2,552	3,775
Total current liabilities	357,042	285,698
Long-term debt	1,591,288	1,588,269
Deferred income taxes	-	-
Derivative financial instruments	3,162	4,200
Asset retirement obligations and other long-term liabilities	60,889	58,701
Commitments and contingencies	-	-
Shareholders' equity:		
Preferred stock, $0.001 par value; authorized shares - 10,000,000; none issued and outstanding	-	-
Common stock, $0.001 par value; 350,000,000 authorized shares; 214,557,830 shares issued and 214,018,609 shares outstanding at June 30, 2011; 213,736,266 shares issued and 213,197,045 shares outstanding at December 31, 2010	215	214
Additional paid-in capital	3,170,496	3,151,513
Accumulated deficit	(1,516,499)	(1,603,696)
Treasury stock, at cost; 539,221 shares at June 30, 2011 and December 31, 2010	(7,479)	(7,479)
Total shareholders' equity	1,646,733	1,540,552
Total liabilities and shareholders' equity	$ 3,659,114	$ 3,477,420

EXCO Resources, Inc.
Consolidated statement of operations

(in thousands, except per share data)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Revenues:				
Oil and natural gas	$ 206,828	$ 118,344	$ 368,056	$ 249,338
Costs and expenses:				
Oil and natural gas production	27,145	31,024	51,789	58,082
Gathering and transportation	19,504	12,873	36,790	23,986
Depreciation, depletion and amortization	85,412	45,339	153,342	84,157
Accretion of discount on asset retirement obligations	933	1,001	1,790	2,090
General and administrative	23,137	25,866	46,560	52,285
Gain on divestitures and other operating items	1,669	(574,946)	4,126	(575,353)
Total costs and expenses	157,800	(458,843)	294,397	(354,753)
Operating income	49,028	577,187	73,659	604,091
Other income (expense):				
Interest expense	(13,679)	(14,476)	(28,495)	(25,110)
Gain on derivative financial instruments	43,273	707	46,694	99,856
Other income	202	57	362	117
Equity income	3,538	5,290	12,083	5,379
Total other income (expense)	33,334	(8,422)	30,644	80,242
Income before income taxes	82,362	568,765	104,303	684,333
Income tax expense	-	4,452	-	4,452
Net income	$ 82,362	$ 564,313	$ 104,303	$ 679,881
Earnings per common share:				
Basic				
Net income	$ 0.39	$ 2.66	$ 0.49	$ 3.20
Weighted average common shares outstanding	213,888	212,497	213,710	212,293
Diluted				
Net income	$ 0.38	$ 2.62	$ 0.48	$ 3.15
Weighted average common and common equivalent shares outstanding	217,513	215,498	217,313	215,520

EXCO Resources, Inc.
Consolidated statement of cash flows

(in thousands)	Six months ended June 30, 2011	Six months ended June 30, 2010
Operating Activities:		
Net income	$ 104,303	$ 679,881
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	153,342	84,157
Stock option compensation expense	5,087	8,463
Accretion of discount on asset retirement obligations	1,790	2,090
Gain on divestitures	-	(574,878)
Income from equity investments	(12,083)	(5,379)
Non-cash change in fair value of derivatives	3,458	21,711
Cash settlements of assumed derivatives	-	907
Deferred income taxes	-	-
Amortization of deferred financing costs;		
discount on the 2018 Notes and premium on the 2011 Notes	3,747	3,847
Effect of changes in:		
Accounts receivable	(48,445)	(65,218)
Other current assets	(3,590)	(4,081)
Accounts payable and other current liabilities	20,424	30,353
Net cash provided by operating activities	228,033	181,853
Investing Activities:		
Additions to oil and natural gas properties, gathering systems and equipment	(474,838)	(263,361)
Property acquisitions	(722,032)	(438,382)
Proceeds from disposition of property and equipment	410,870	956,296
Investment in equity investments	(10,279)	(68,500)
Return of investment in equity investments	125,000	-
Restricted cash	12,502	(16,337)
Advances to Appalachia JV	(1,309)	(30,448)
Deposit on pending acquisitions	464,151	-
Other	(1,250)	-
Net cash provided by (used in) investing activities	(197,185)	139,268
Financing Activities:		
Borrowings under credit agreements	380,000	1,352,399
Repayments under credit agreements	(377,500)	(1,622,463)
Proceeds from issuance of common stock	11,063	9,091
Payment of common stock dividends	(17,106)	(12,740)
Settlements of derivative financial instruments with a financing element	-	(907)
Deferred financing costs and other	(6,348)	(16,881)
Net cash provided by (used in) financing activities	(9,891)	(291,501)
Net increase in cash	20,957	29,620
Cash at beginning of period	44,229	68,407
Cash at end of period	$ 65,186	$ 98,027
Supplemental Cash Flow Information:		
Cash interest payments	$ 37,564	$ 25,520
Income tax payments	$1,458	$ -
Supplemental non-cash investing and financing activities:		
Capitalized stock option compensation	$ 2,800	$ 2,175
Capitalized interest	$ 15,748	$ 6,114
Issuance of common stock for director services	$ 34	$ 25

EXCO Resources, Inc.
Consolidated EBITDA
And adjusted EBITDA reconciliations and statement of cash flow data
(Unaudited)

(in thousands)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Net income	$ 82,362	$ 564,313	$ 104,303	$ 679,881
Interest expense	13,679	14,476	28,495	25,110
Income tax expense	-	4,452	-	4,452
Depreciation, depletion and amortization	85,412	45,339	153,342	84,157
EBITDA(1)	181,453	628,580	286,140	793,600
Accretion of discount on asset retirement obligations	933	1,001	1,790	2,090
Gain on divestitures and non-recurring other operating items	2,980	(574,878)	5,955	(574,878)
Equity method income	(3,538)	(5,290)	(12,083)	(5,379)
Non-cash change in fair value of derivative financial instruments	(20,056)	45,831	3,458	23,729
Gains from early termination of derivative financial instruments	-	-	-	(37,936)
Stock based compensation expense	2,419	3,854	5,087	8,463
Adjusted EBITDA (1)	$ 164,191	$ 99,098	$ 290,347	$ 209,689
Interest expense (2)	(13,679)	(14,476)	(28,495)	(27,128)
Income tax expense	-	(4,452)	-	(4,452)
Amortization of deferred financing costs, premium on the 2011 Notes and discount on the 2018 Notes	1,800	3,937	3,747	3,847
Deferred income taxes	-	-	-	-
Gains from early termination of derivative financial instruments	-	-	-	37,936
Non-recurring other operating items	(2,980)	-	(5,955)	-
Changes in operating assets and liabilities	(372)	6,443	(31,611)	(38,946)
Settlements of derivative financial instruments with a financing element	-	-	-	907
Net cash provided by operating activities	$ 148,960	$ 90,550	$ 228,033	$ 181,853

(in thousands)	Three months ended June 30, 2011	Three months ended June 30, 2010	Six months ended June 30, 2011	Six months ended June 30, 2010
Statement of cash flow data (unaudited):				
Cash flow provided by (used in):				
Operating activities	$ 148,960	$ 90,550	$ 228,033	$ 181,853
Investing activities	(343,646)	263,088	(197,185)	139,268
Financing activities	251,344	(303,415)	(9,891)	(291,501)
Other financial and operating data:				
EBITDA(1)	181,453	628,580	286,140	793,600
Adjusted EBITDA(1)	164,191	99,098	290,347	209,689

(1) Earnings before interest, taxes, depreciation, depletion and amortization, or "EBITDA" represents net income adjusted to exclude interest expense, income taxes and depreciation, depletion and amortization. "Adjusted EBITDA" represents EBITDA adjusted to exclude non-recurring other operating items, including costs associated with our special committee's review of strategic alternatives, accretion of discount on asset retirement obligations, non-cash changes in the fair value of derivatives, gains from early termination of derivatives, 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, these measures are used in covenant calculations required under our credit agreement and the indenture governing our 7.5% senior notes due September 15, 2018. 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 generally accepted accounting principles, or 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.

(2) Excludes non-cash changes in fair value of $2.0 million for the six months ended June 30, 2010 for interest rate swaps included in GAAP interest expense. Our interest rate swaps expired on February 14, 2010 and we have not entered into any new interest rate swap agreements as of June 30, 2011.

EXCO Resources, Inc.
Summary of operating data

	Three months ended June 30, 2011	Three months ended June 30, 2010	% Change	Six months ended June 30, 2011	Six months ended June 30, 2010	% Change
Production:						
Oil (Mbbls)	178	168	6%	371	327	13%
Natural gas (Mmcf)	44,467	25,539	74%	79,992	48,376	65%
Oil and natural gas (Mmcfe)	45,535	26,547	71%	82,218	50,338	63%
Average daily production (Mmcfe)	500	292	71%	454	278	63%
Average sales prices (before derivative financial instrument activities):						
Oil (per Bbl)	$ 99.16	$ 74.44	33%	$ 94.40	$ 74.83	26%
Natural gas (per Mcf)	4.25	4.14	3%	4.16	4.65	-11%
Total production (per Mcfe)	4.54	4.46	2%	4.48	4.95	-9%
Average costs (per Mcfe):						
Oil and natural gas operating costs	$ 0.45	$ 0.85	-47%	$ 0.48	$ 0.83	-42%
Production and ad valorem taxes	0.14	0.32	-56%	0.15	0.33	-55%
Gathering and transportation costs	0.43	0.48	-10%	0.45	0.48	-6%
Depletion	1.77	1.55	14%	1.75	1.49	17%
Depreciation and amortization	0.10	0.16	-38%	0.11	0.18	-39%
General and adminstrative	0.51	0.97	-47%	0.57	1.04	-45%