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EXCO Resources, Inc.

First Quarter 2008 Review

May 2008

Management Participants

Doug Miller	Chairman and CEO
Steve Smith	Vice Chairman and President
Doug Ramsey	Vice President and CFO
Hal Hickey	Vice President and COO
Mark Wilson	Vice President and CAO
Paul Rudnicki	Vice President

Forward Looking Statements

This presentation contains forward-looking statements, as defined in Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. These forward-looking statements relate to, among other things, the following:

- our future financial and operating performance and results;
- our business strategy;
- market prices;
- our future commodity price risk management activities; and
- our plans and forecasts.

We have based these forward-looking statements on our current assumptions, expectations and projections about future events.

We use the words "may," "expect," "anticipate," "estimate," "believe," "continue," "intend," "plan," "budget" and other similar words to identify forward-looking statements. You should read statements that contain these words carefully because they discuss future expectations, contain projections of results of operations or of our financial condition and/or state other "forward-looking" information. We do not undertake any obligation to update or revise publicly any forward-looking statements, except as required by law. These statements also involve risks and uncertainties that could cause our actual results or financial condition to materially differ from our expectations in this presentation, including, but not limited to:

- fluctuations in prices of oil and natural gas;
- imports of foreign oil and natural gas, including liquefied natural gas;
- future capital requirements and availability of financing;
- estimates of reserves and economic assumptions used in connection with our acquisitions;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- exploratory risks, including our Marcellus and Huron shale plays in Appalachia and our Haynesville shale play in East Texas/North Louisiana;
- risks associated with operation of natural gas pipelines and gathering systems;
- discovery, acquisition, development and replacement of oil and natural gas reserves;
- cash flow and liquidity;
- impact of our private placement of preferred stock and the impact of dividends on our capital resources and liquidity;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- marketing of oil and natural gas;
- developments in oil-producing and natural gas-producing countries;
- title to our properties;
- competition;
- litigation;
- general economic conditions, including costs associated with drilling and operation of our properties;
- governmental regulations;
- receipt of amounts owed to us by purchasers of our production and counterparties to our derivative financial instruments;
- deciding whether or not to enter into derivative financial instruments;
- events similar to those of September 11, 2001;
- 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.

Forward Looking Statements (continued)

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 Reports on Form 10-K and our Quarterly Reports on Form 10-Q.

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 has generally permitted oil and natural gas companies, in filings made with the SEC, to disclose only 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. We use the terms “probable”, “possible”, “potential” or “unproved” to describe volumes of reserves potentially recoverable through additional drilling or recovery techniques that the SEC’s guidelines prohibit us from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved 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 for the year ended December 31, 2007 available on our website at www.excoresources.com under the Investor Relations tab or by calling us at 214-368-2084.

EXCO Resources, Inc.

Financial Review

Steve Smith

First Quarter 2008 Corporate Highlights

Significant growth in all financial and operational metrics

(In thousands, except per share and production)	Q1 2007 Amount	Q1 2007 Per Share	Q1 2008 Amount	Q1 2008 Per Share
Oil and natural gas revenues[(1)(2)]	$ 150,568		$ 320,705	
Adjusted net income available to common shareholders[(2)]	$ 7,250	$ 0.07[(4)]	$ 29,685	$ 0.28[(4)]
Adjusted EBITDA[(2)]	$ 114,129	$ 1.05[(5)]	$ 254,015	$ 1.20[(5)]
Cash flow from operations[(2)(3)]	$ 47,890	$ 0.44[(5)]	$ 222,062	$ 1.05[(5)]
Average daily production – Mmcfe/d	192		386	
Pipeline and marketing income	$ 5,345		$ 7,427	

- Record production of 386 Mmcfe/d for the first quarter 2008 **doubled prior year's quarter** of 192 Mmcfe/d
- Realized a **24% reduction in oil and natural gas production costs**; $0.95 per Mcfe in the first quarter 2008 compared to $1.25 for the prior year's quarter
- Drilling and development **capital expenditures totaled a record $152 million** in the first quarter
- Expect a **~20% increase in average daily production** between 2007 and 2008

(1) Including cash settlements on derivative financial instruments
(2) Non-GAAP measures, please see tables on slides 23 to 27 for reconciliations to most comparable GAAP measures
(3) Cash flow from operations before changes in working capital
(4) Computed using diluted shares of 106,447,268 for first quarter 2007 and 106,474,591 for first quarter 2008
(5) Computed using diluted shares (including the potential additional shares for conversion of preferred stock) of 108,786,449 for first quarter 2007 and 211,737,749 for first quarter 2008

First Quarter 2008 Corporate Highlights

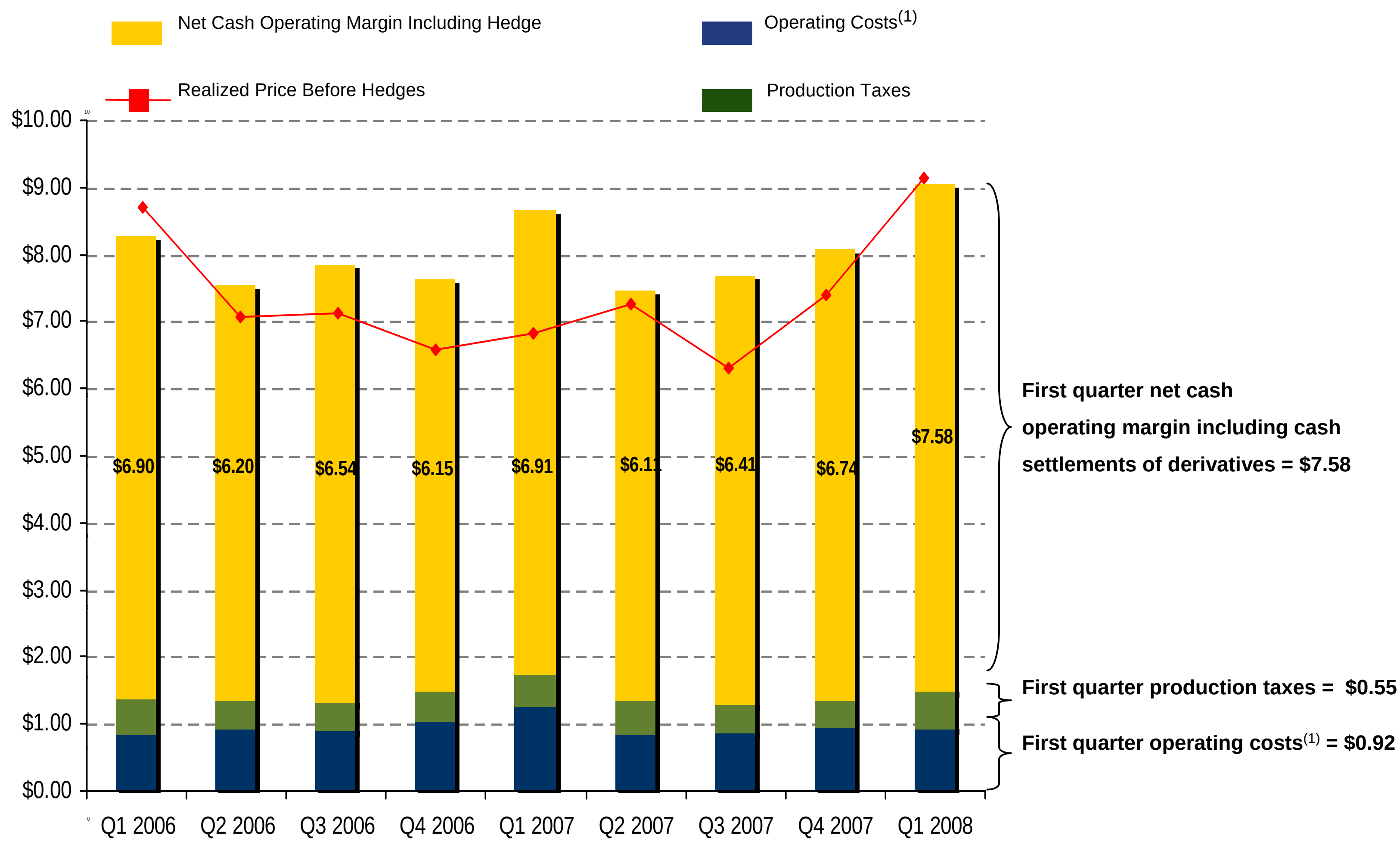
Positioned to exploit emerging potential with continued emphasis on existing portfolio

- Marcellus, Huron and Haynesville shales
  - Continue to add acreage to supplement our key positions throughout the heart of the plays
  - Based on our internal studies and industry announcements, we have now **identified 7-12 Tcfe of potential** in the Marcellus and Huron shales and **2-5 Tcfe of potential** in the Haynesville shale
  - Increased our 2008 capital budget for the Marcellus shale by $150 million; our approved **capital budget now totals $800 million**

- Numerous initiatives underway to grow reserves and production in existing areas
  - Achieved outstanding drilling results in all areas; especially at Vernon, Holly Caspiana and Sugg Ranch
  - Successfully **reduced spud to rig release days by 30%** in some areas
  - Continued our efforts to apply artificial lift technology to new areas, with encouraging initial results
  - Implemented refrac and recompletions across the portfolio; recent Vernon Field refrac **increased production from 1.0 Mmcfe/d to 3.9 Mmcfe/d**

Performance Highlights

Increasing cash operating margin will fund our increased capital spending plans



(1) Does not include non-cash stock based compensation costs of $0.03 per Mfce for the first quarter 2008

Liquidity and Financial Position

(in thousands)	March 31, 2008	May 1, 2008
Cash	$ 9,113	$ 80,078
Bank debt (LIBOR + 125-175bps)	$ 2,024,200	$ 2,105,500
Senior notes (7 $^{1}/_{4}$%)[1]	444,720	444,720
Total debt	$ 2,468,920	$ 2,550,220
7% convertible preferred[2]	$ 2,000,000	
Common shareholders' equity	925,191	
Total capitalization	$ 5,394,111	
Net debt to total capitalization	46%	
Borrowing base	$ 2,475,000	$ 2,475,000
Unused borrowing base[3]	$ 446,500	$ 365,200

(1) Excludes unamortized bond premium
(2) Excludes $7 million in offering costs
(3) Net of $4.3 million in letters of credit at both March 31, 2008 and May 1, 2008

Hedge Position
As of March 31, 2008

NYMEX Swaps	Gas Mmcf	Contract price per Mmcf	Oil Mbbls	Contract price per Bbl	Percent Hedged[1]
Q2 2008	26,695	$ 8.27	355	$ 68.23	80%
Q3 2008	26,900	8.29	358	68.20	79%
Q4 2008	26,910	8.39	358	68.16	77%
2009	100,530	8.18	1,215	69.11	72%
2010	40,748	8.03	473	84.85	29%
2011	9,125	7.97	-	-	6%
2012	1,830	4.51	-	-	1%
2013	1,825	4.51	-	-	1%
Total	234,563	$ 8.14	2,759	$ 71.45	
	Total of 251,117 Mmcfe Hedged at $8.38				

- Target hedging 65-80% of production volumes for 3-5 years
- Hedging program covers long term debt
- Only 14% of year end 2007 Proved Reserves hedged
- $700 million of interest rate swaps at an average LIBOR rate of 2.66%

(1) Based on 2008 production guidance

2008 Guidance

($ in thousands, except per unit amounts)	2008E[1] Low	2008E[1] High
Production:		
Oil – Mbbls	2,007	2,037
Gas – Mmcf	132,149	134,749
Mmcfe	144,191	146,991
Per day – Mmcfe	394	402
Differentials to NYMEX:		
Oil per Bbl	($3.11)	($2.93)
Gas per Mcf	97%	100%
Lease operating expense	$129,780	$138,780
Stock based compensation - LOE	$4,880	$6,280
Gathering expense – per Mcfe	$0.10	$0.14
Production tax rate	6.4%	7.2%
Interest income	$1,870	$2,620
Midstream income	$34,930	$36,430
Depletion rate per Mcfe	$3.03	$3.10
Depreciation rate per Mcfe	$0.14	$0.21
Asset retirement obligation	$5,950	$6,700
Cash G&A	$68,410	$71,410
Non-cash stock comp	$10,220	$14,220
Interest expense	$127,790	$133,790
Tax rate	40%	40%
Cash tax rate	0%	0%
Preferred dividends	$140,000	$140,000
Fully diluted shares outstanding[2]	108,759	109,521
Adjusted EBITDA at Midpoint[3]	$981,700	

(1) 2008 guidance includes actual results for the first quarter 2008
(2) Fully diluted shares outstanding excludes 105,263,158 shares resulting from the potential conversion of the preferred stock
(3) 2008 estimates based on NYMEX $90 oil and $9 natural gas for the second quarter through the fourth quarter

Quarterly 2008 Guidance

($ in thousands, except per unit amounts)	2ndQ 2008E Low	2ndQ 2008E High	3rdQ 2008E Low	3rdQ 2008E High	4thQ 2008E Low	4thQ 2008E High
Production:						
Oil - Mbbls	490	500	500	510	510	520
Gas - Mmcf	32,600	33,400	33,300	34,200	34,200	35,100
Mmcfe	35,500	36,400	36,300	37,300	37,300	38,200
Per day - Mmcfe	390	400	395	405	405	415
Differentials to NYMEX:						
Oil per Bbl	($3.75)	($3.50)	($3.75)	($3.50)	($3.75)	($3.50)
Gas per Mcf	95%	99%	95%	99%	95%	99%
Lease operating expense	$32,200	$35,200	$32,700	$35,700	$32,700	$35,700
Stock based compensation – LOE	$750	$1,250	$750	$1,250	$2,390	$2,790
Gathering expense – per Mcfe	$0.10	$0.15	$0.10	$0.15	$0.10	$0.15
Production tax rate	6.5%	7.5%	6.5%	7.5%	6.5%	7.5%
Interest income	$250	$500	$250	$500	$250	$500
Midstream income	$7,500	$8,000	$10,000	$10,500	$10,000	$10,500
Depletion rate per Mcfe	$3.05	$3.15	$3.05	$3.15	$3.05	$3.15
Depreciation rate per Mcfe	$0.10	$0.20	$0.15	$0.25	$0.15	$0.25
Asset retirement obligation	$1,545	$1,795	$1,545	$1,795	$1,545	$1,795
Cash G&A	$15,700	$16,700	$15,800	$16,800	$16,300	$17,300
Non-cash stock comp	$2,070	$3,070	$2,070	$3,070	$4,070	$6,070
Interest expense	$31,800	$33,800	$31,800	$33,800	$31,800	$33,800
Tax rate	40%	40%	40%	40%	40%	40%
Cash tax rate	0%	0%	0%	0%	0%	0%
Preferred dividends	$35,000	$35,000	$35,000	$35,000	$35,000	$35,000
Fully diluted shares outstanding(1)	109,500	110,500	109,500	110,500	109,500	110,500
Adjusted EBITDA at Midpoint(2)	$233,200		$242,200		$252,300	

(1) Fully diluted shares outstanding excludes 105,263,158 shares resulting from the potential conversion of the preferred stock
(2) 2008 estimates based on NYMEX $90 oil and $9 natural gas for the second quarter through the fourth quarter

EXCO Resources, Inc.

Operational Review

Hal Hickey

Operational Highlights
East Texas/North Louisiana
First Quarter 2008

- Vernon
  - Drilled and completed 6 wells with average IP of 6.5 Mmcfe/d gross (4.4 Mmcfe/d net)
  - A recent completion had highest rate since EXCO acquisition – 10.3 Mmcfe/d gross
  - Expanded southern and western field limits and number of drilling locations; adding 4th rig and plan to drill 31 wells during 2008
  - Reprocessing seismic as we evaluate an additional 65,000 net prospective acres in the Vernon area
- Holly / Caspiana
  - Drilled and completed 12 wells in the first quarter, with IP average exceeding 1 Mmcfe/d
  - Encouraging results from initial 20-acre tests
  - Expanding field limits; drilling with 4-5 rigs
- Overall, rig spud to release days down 20-30%; drilling and completion costs down 10%
- Haynesville shale
  - Currently hold more than 100,000 net acres with deep rights in the play and are actively acquiring additional acreage
  - Drilled two vertical evaluation wells with encouraging results
  - Plan to add additional rig mid-2008 for horizontal program
  - We believe that there are at least 2-5 Tcfe of potential reserves

Operational Highlights
East Texas/North Louisiana
First Quarter 2008

- Cotton Valley
  - Plan to drill eight Cotton Valley horizontal wells during 2008, beginning in the second quarter
  - Continuing leasing and evaluation of approximately 40,000 prospective Cotton Valley acres, with encouraging results
  - One well on newly leased acreage had an initial gross production rate of 430 barrels of oil and 1.0 Mmcf of natural gas per day

- Midstream
  - Completed acquisition of 230 mile gathering system in East Texas for $56 million from a private seller
  - Throughput has increased from 460 Mmcf/d at year end 2007 to 535 Mmcf/d today
  - 57-mile, $37.6 million expansion of our TGG pipeline continues; first phase on line in early May; overall expansion expected to be complete by late summer 2008, adding at least 100 Mmcf/d in total

Operational Highlights
Appalachia
First Quarter 2008

- Production
  - Set monthly production record of 59 Mmcfe/d in March 2008
  - Enhanced production by 30% on 50 wells in Central Pennsylvania through installation of artificial lift equipment

- Drilling
  - Achieved 100% drilling success rate on 17 gross (16.25 net) wells
  - Had one rig drilling on March 31, 2008; have increased rig count to seven as frost law restrictions have lifted

- EOG Appalachia acquisition
  - Closed a $388 million acquisition (after customary closing adjustments) of 2,500 producing wells, approximately 2,000 drilling locations and 16 Mmcfe/d of production in our core Central Pennsylvania operating area, Ohio and West Virginia
  - Acquired assets include 340 Bcfe of shallow 3P reserves (158 Bcfe proved), with 80% of the acquisition value situated among existing EXCO assets in Central Pennsylvania
  - Of the more than 325,000 gross acres (283,000 net) associated with the acquisition,144,000 gross (120,000 net) are in West Virginia and Ohio and have deep rights

Operational Highlights
Appalachia
First Quarter 2008

- Marcellus shale
  - Currently hold 382,000+ net acres with 243,000+ net acres in the fairway of the play; have negotiated an additional 33,000 net acres through recent leasing efforts
  - Began drilling first of four 2008 Marcellus horizontal test wells in early April
  - Spud first of ten 2008 vertical Marcellus wells in April
  - We believe that there are at least 6-10 Tcfe of potential reserves

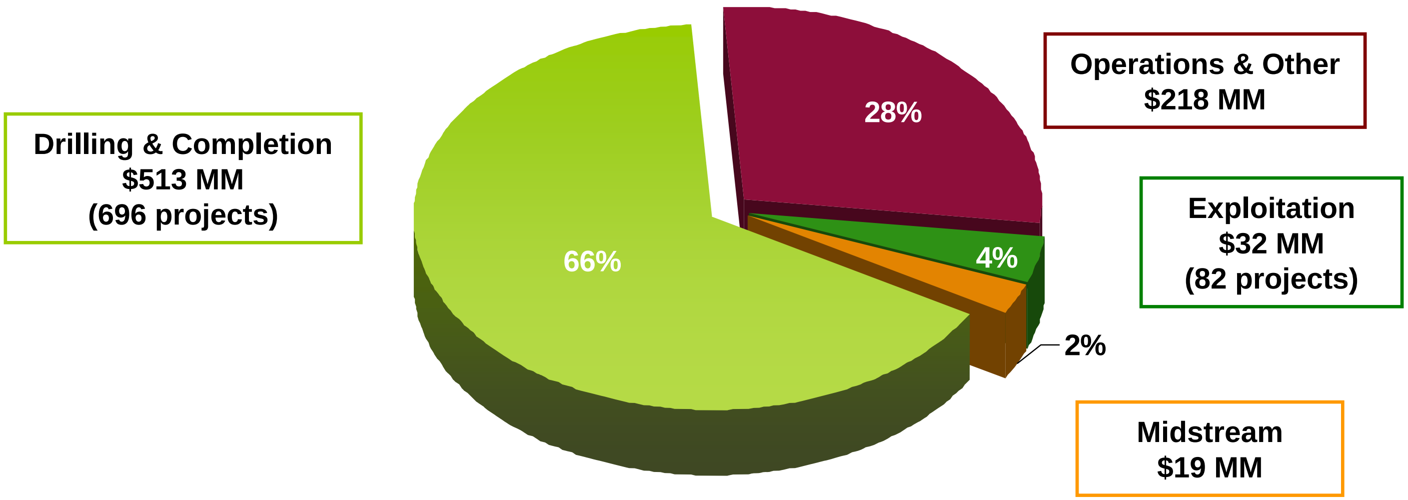
- Huron shale
  - Currently hold 120,000+ net acres in the Huron shale in West Virginia
  - Planning 2008 drilling program; will drill 2-4 horizontal wells
  - We believe that there are at least 1-2 Tcfe of potential reserves

Operational Highlights
Other Areas
First Quarter 2008

- Permian – Canyon Sand Field
  - Drilled 25 gross (24.3 net) wells in the first quarter with three operated rigs
  - Plan to drill 98 gross (95 net) wells in 2008
  - First quarter 2008 net production of 24.0 Mmcfe/d is up from 19.7 Mmcfe/d in November 2007, when EXCO took over operations
  - Negotiated a joint venture adding approximately 11,000 contiguous net acres
  - Currently shooting and evaluating 3-D seismic to identify additional opportunities
- Rockies
  - Following encouraging results based on the logs of our Birdseye prospect, eight wells will be drilled in Wyoming's Wind River and Big Horn Basins during 2008 to continue evaluating our potential 1 Tcfe of unbooked upside
- Mid-Continent
  - Drilled and completed six wells (gross) in the Mid-Continent area achieving a 100% success rate; have two rigs running
  - Plan to drill 57 gross (33.0 net) wells in the Mid-Continent area during 2008
  - Completed $30 million acquisition in Mocane Laverne area, adding 1.8 Mmcfe/d of production and 12.5 Bcfe of proved reserves

2008 Capital Budget and Drilling Schedule

- Our development budget totals $800 million, which includes $150 million for Marcellus shale leasing and drilling



2008 Capital Program

Area	Drilling & Completion (Net MM)	Gross Projects (#)	Exploitation (Net MM)	Gross Projects (#)	Operations & Other (Net MM)	Total 2008 Captial Budget (Net MM)[(1)]
ETX / NLA	$245	139	$26	25	$68	**$339**
Appalachia	111	335	1	22	131	**243**
Mid-Continent	48	57	4	30	5	**57**
Permian	98	156	1	3	10	**109**
Rockies	11	9	-	2	4	**15**
Total	$513	696	$32	82	$218	**$763**

(1) Does not include $18MM for IT and other and $19MM for Midstream

EXCO Resources, Inc.

Appendix

Operating Results

(in thousands)	First Quarter 2007	First Quarter 2008	Period-to-Period Change Amount	Period-to-Period Change Percent
Revenues and other income:				
Oil	$ 15,105	$ 49,017	$ 33,912	225%
Natural gas	103,390	268,673	165,283	160%
Cash settlement on derivatives	32,073	3,015	(29,058)	(91)%
Revenues including cash settlements on derivatives	150,568	320,705	170,137	113%
Pipeline and marketing income	5,345	7,427	2,082	39%
Interest and other income	1,380	1,118	(262)	(19)%
Total revenues	157,293	329,250	171,957	109%
Costs and expenses:				
Operating costs – Cash	$ 21,702	$ 32,180	$ 10,478	48%
Operating costs – Non-cash[1]	-	991	991	-
Production taxes	8,376	19,310	10,934	131%
Total production costs	30,078	52,481	22,403	74%
Gathering and transportation costs	821	3,131	2,310	281%
General and administrative - Cash	12,265	20,614	8,349	68%
General and administrative – Non-cash[1]	1,910	2,013	103	5%
Total costs and expenses	45,074	78,239	33,165	74%
Non-cash adjustments from above	1,910	3,004	-	-
Adjusted EBITDA[2]	$ 114,129	$ 254,015	$ 139,886	123%

(1) Stock based compensation
(2) Non-GAAP measure - please see table on slides 25 and 26 for reconciliation to most comparable GAAP measure

Unit Operating Statistics

	First Quarter		Period-to-Period Change	
	2007	2008	Amount	Percent
Production volumes:				
Oil – Mbbls	275	507	232	84%
Gas – Mmcf	15,663	32,049	16,386	105%
Total - Mmcfe	17,313	35,091	17,778	103%
Realized pricing[1]:				
Oil per Bbl	$ 54.93	$ 96.68	$ 41.75	76%
Gas per Mcf	6.60	8.38	1.78	27%
Per Mcfe	6.84	9.05	2.21	32%
Production costs per Mcfe:				
Operating costs[2]	$ 1.25	$ 0.92	$ (0.33)	(26)%
Production taxes	0.48	0.55	0.07	15%
Total production costs	1.73	1.47	(0.26)	(15)%
Gathering and transportation costs	$ 0.05	$ 0.09	$ 0.04	80%
Cash operating margin	$ 5.06	$ 7.49	$ 2.43	48%
Effects of cash settlements on derivatives	1.85	0.09	(1.76)	(95)%
Net cash operating margin	6.91	7.58	0.67	10%

(1) Does not include the effects of derivative financial instruments

(2) Does not include stock based compensation which would have increased operating costs per Mcfe by $0.03 for the first quarter 2008

Non-GAAP Reconciliations

Revenues and Adjusted Revenues

(in thousands)	Three months ended March 31, 2007	Three months ended March 31, 2008
Oil and natural gas revenues, before derivative financial instruments	$ 118,495	$ 317,690
Cash settlements on derivative financial instruments	32,073	3,015
Subtotal, revenues including cash settlements on derivative financial instruments	150,568	320,705
Non-cash loss on oil and natural gas derivative financial instruments	(128,092)	(344,209)
Oil and natural gas revenues	22,476	(23,504)
Pipeline and marketing	5,345	7,427
Interest and other	1,380	1,118
Total revenues, marketing and other income, GAAP	29,201	(14,959)
Elimination of non-cash oil and natural gas derivative financial instrument activity included in GAAP revenues	128,092	344,209
Adjusted revenues[1]	$ 157,293	$ 329,250

(1) EXCO does not designate its derivatives as hedges. As a result, unrealized gains or losses in the fair market value of our derivatives are recognized as a component of current revenues. Adjusted revenues are not a measure of revenues in accordance with GAAP. Management believes that adjusted revenue is a meaningful measure to investors and rating agencies as it presents the combination of actual revenues before the impact of oil and natural gas derivatives in accordance with GAAP, combined with the actual cash receipts or settlements arising from the oil and natural gas derivative program. Adjusted revenue specifically excludes the non-cash unrealized gains or losses from derivative activities as the non-cash impact of the changes in the fair value of derivatives does not impact our current liquidity and cash flows used to fund our operations, execute our capital program and make acquisitions.

Non-GAAP Reconciliations

Cash Flow From Operations

(in thousands)	Three months ended March 31, 2007	Three months ended March 31, 2008
Cash flow from operations, GAAP	$ 32,551	$ 199,510
Net change in working capital	15,339	12,085
Settlements of derivative financial instruments with a financing element	-	10,467
Cash flow from operations before changes in working capital, non-GAAP measure[(1)]	$ 47,890	$ 222,062

(1) Cash flow from operations before working capital changes and adjustments for settlements of derivative financial instruments with a financing element 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 provide 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 with the intended measure of our ability to provide cash to fund operations and development activities.

Non-GAAP Reconciliations

Adjusted Net Income

(in thousands, except per share)	Three months ended March 31, 2007 Amount	Three months ended March 31, 2007 Per Share	Three months ended March 31, 2008 Amount	Three months ended March 31, 2008 Per Share
Net loss, GAAP	$ (87,697)		$ (162,839)	
Adjustments:				
Non-cash mark-to-market losses on oil and natural gas derivative financial instruments, before taxes	128,092		344,209	
Non-cash mark-to-market losses on interest rate derivative financial instruments, before taxes	-		3,631	
Nonrecurring financing costs, before taxes[(1)]	32,100		-	
Income taxes on adjustments	(64,109)		(120,316)	
Total adjustments, net of taxes	96,083		227,524	
Adjusted net income	$ 8,386		$ 64,685	
Net loss available to common shareholders, GAAP[(2)]	$ (88,833)	$ (0.85)	$ (197,839)	$ (1.89)
Impact of potentially dilutive common stock equivalents[(3)]		0.02		0.03
Adjustments shown above[(4)]	96,083	0.90	227,524	2.14
Adjusted net income available to common shareholders[(4)]	$ 7,250	$ 0.07	$ 29,685	$ 0.28

(1) Interest expense for the three months ended March 31, 2007 includes one time charges of $32.1 million incurred during the first quarter 2007. Expenses associated with the payoff of the EXCO Partners Operating Partnership Senior Term Credit Agreement included a $13.0 million redemption premium, a $9.2 million write-off of deferred financing costs, and a $3.0 million write-off of unamortized original issue discount. In addition, $6.9 million of commitment fees were expensed in connection with other debt arrangements that were terminated. Interest expense for the three months ended March 31, 2008 includes an increase of $3.6 million as a result of non-cash losses resulting from interest rate swaps entered into during the first quarter 2008.

(2) Per share amount is based on weighted average number of common shares outstanding of 104,201,768 and 104,682,724 for the three months ended March 31, 2007 and 2008, respectively.

(3) Potentially dilutive common stock equivalents were 2,245,500 and 1,791,867 for the three months ended March 31, 2007 and 2008, respectively. For the computation of adjusted net income per share, these common stock equivalents have been included to reflect the impact of the adjustments which result in income as opposed to a loss.

(4) Computed using diluted shares of 106,447,268 and 106,474,591 for the three months ended March 31, 2007 and 2008, respectively.

Non-GAAP Reconciliations

EBITDA and adjusted EBITDA reconciliations

(unaudited, in thousands)	Three months ended March 31, 2007	Three months ended March 31, 2008
Net loss	$ (87,697)	$ (162,839)
Interest expense	76,709	36,020
Income tax benefit	(57,152)	(76,912)
Depreciation, depletion and amortization	51,324	109,217
EBITDA[1]	**(16,816)**	**(94,514)**
Accretion of discount on asset retirement obligations	943	1,316
Non-cash change in fair value of derivative financial instruments	128,092	344,209
Stock based compensation expense	1,910	3,004
Adjusted EBITDA[1]	**$ 114,129**	**$ 254,015**
Interest expense[2]	(76,709)	(32,390)
Income tax benefit	57,152	76,912
Amortization of deferred financing costs, premium on 7¼% senior notes due 2011 and discount on long-term debt	9,355	406
Loss on sale of assets	-	31
Deferred income taxes	(56,037)	(76,912)
Changes in operating assets and liabilities	(15,339)	(12,085)
Settlements of derivative financial instruments with a financing element	-	(10,467)
Net cash provided by operating activities	**$ 32,551**	**$ 199,510**
Statement of cash flow data:		
Cash flow provided by (used in):		
Operating activities[2]	$ 32,551	$ 199,510
Investing activities	(1,401,356)	(604,869)
Financing activities	1,515,661	358,962

Non-GAAP Reconciliations

(1) Earnings before interest, taxes, depreciation, depletion and amortization, or “EBITDA” represents net income adjusted to exclude interest expense, income taxes, depreciation, depletion and amortization. “Adjusted EBITDA” represents EBITDA adjusted to exclude accretion of discount on asset retirement obligations, non-cash changes in the fair value of derivatives and stock-based compensation. 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 agreements and the indenture governing our 7 1/4 % senior 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 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 change in fair value of interest rate swaps included in GAAP interest expense.