EXCO Resources, Inc.

Third Quarter 2008 Review

November 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;
- continued disruption of credit and capital markets and the ability of financial institutions to honor their commitments, such as the events which occurred during the third quarter of 2008 and thereafter, for an extended period of time;
- 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/Bossier 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;
- 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, the availability of capital from our revolving credit facilities and liquidity from capital markets. 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.

Third Quarter 2008 Introduction

Doug Miller

- Normalized production for the quarter on target at 400 Mmcfe/d excluding hurricane impacts of 3 Mmcfe/d; current production is approximately 406 Mmcfe/d
- Year-over-year, first nine months of production was up 24%
- Adjusted EBITDA was ahead of projected target; up 42% year-over-year nine months
- Emphasizing shale in East Texas/North Louisiana and Appalachia
  - Selective leasing to enhance position
  - Testing to delineate shales, refine completion technology and hold acreage
  - Drilling horizontal and vertical wells
  - Shifting 2009 focus to development
- Reviewing and reducing certain conventional drilling levels in light of current commodity prices and drilling costs

EXCO Resources, Inc.

Financial Review

Steve Smith

Third Quarter 2008 Corporate Highlights

Significant growth in financial and operational metrics

(In thousands, except per share and production)	Q3 2008 Amount	Q3 2008 Per Share	Q3 2007 Amount	Q3 2007 Per Share
Oil and natural gas revenues[1,2]	$ 332,365		$ 274,565	
Adjusted net income available to common shareholders[2]	$ 44,969	$ 0.23[4]	$ (20,473)	$ (0.20)[4]
Adjusted EBITDA[2]	$ 248,870		$ 214,668	
Cash flow from operations[2,3]	$ 211,819	$ 0.98[5]	$ 184,451	$ 0.87[5]
Average daily production – Mmcfe/d	397		375	
Midstream income:				
Before intercompany eliminations	$ 7,848		$ 6,634	

- Reported adjusted EBITDA of ~$249 million and record production of 397 Mmcfe/d
- Completed 2008 shale leasing programs in Appalachia and East Texas/North Louisiana
- Continued drilling and testing shales across portfolio
- Completed 2008 expansion of midstream intrastate pipeline

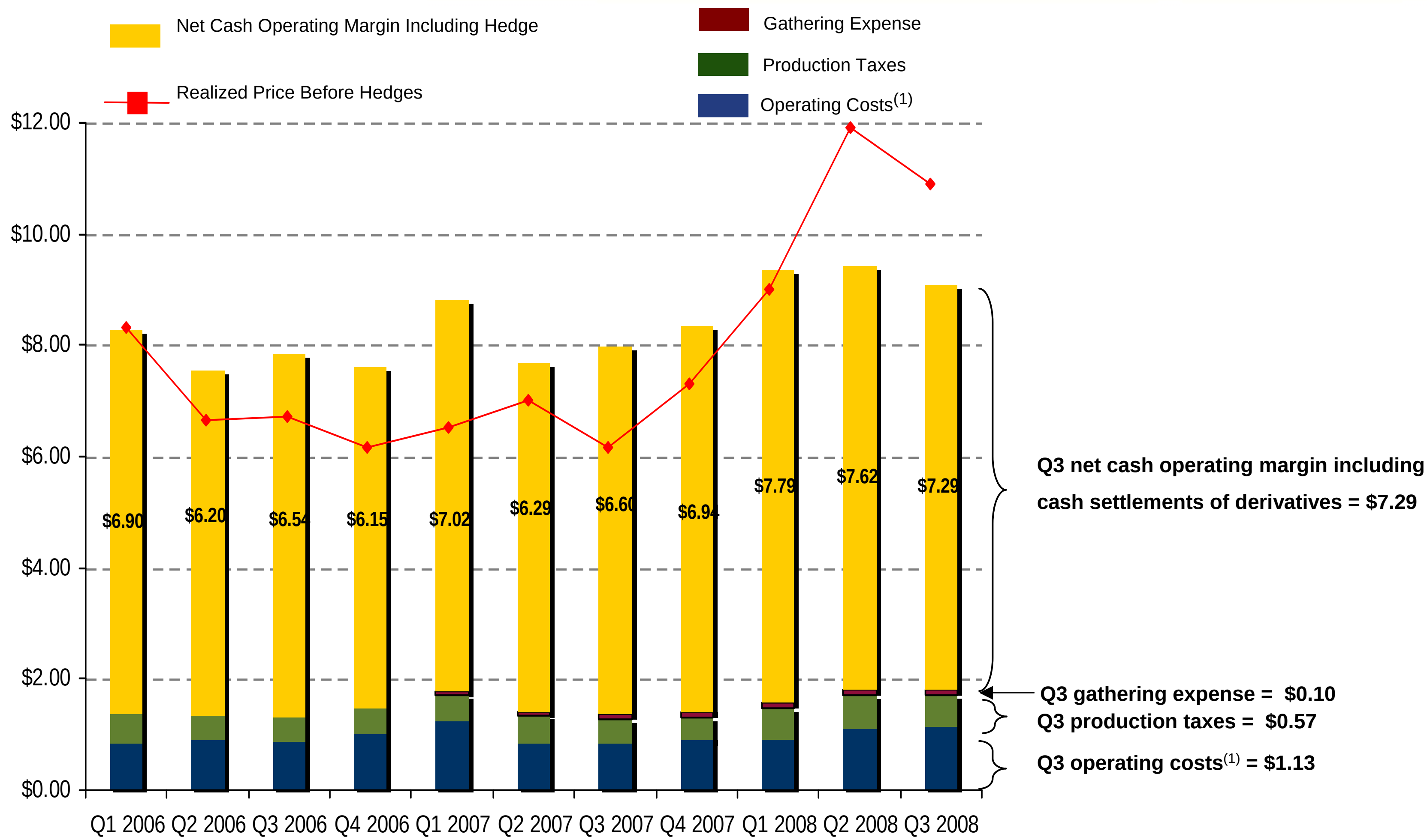
(1) Including cash settlements on derivative financial instruments
(2) Non-GAAP measure, please see tables on slides 28 to 32 for reconciliations to most comparable GAAP measures
(3) Cash flow from operations before changes in working capital
(4) Computed using diluted shares of 196,773,307 for third quarter 2008 and 104,414,844 for third quarter 2007
(5) Computed using diluted shares of 216,214,367 for third quarter 2008 and 211,946,491 for third quarter 2007

Third Quarter 2008 Highlights
Exposed to three emerging shale plays

- Haynesville Activity
  - Increased our shale acreage through leasing
  - Averaged 200 feet of net pay in Harrison County, TX and Caddo and DeSoto Parishes, LA
  - Two recent vertical wells in DeSoto Parish, LA flowed 1.3 and 1.0 Mmcfe/d at 6,100 and 6,600 psi flowing casing pressures, respectively
  - Drilled and cased first horizontal well with 4,400' lateral; planning November completion
- Marcellus Activity
  - Drilled and completed two horizontal wells in Central Pennsylvania; drilling third horizontal in West Virginia
  - First well produced 900 Mcf/d spot rate from single stage fracture stimulation; second well produced 3.4 Mmcf/d spot rate from four stage fracture stimulation
- Huron Activity
  - Drilled and completed five horizontal wells
  - Had spot rates in excess of 400 Mcf/d, as forecast
- Midstream Activity
  - Major expansion in ETX completed; well situated for future Haynesville production
  - Evaluating additional expansion opportunities to support play development

Third Quarter 2008 Performance Highlights

Stable operating cash margins in volatile price environment



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

Third Quarter 2008
Ceiling test write-down

- Q3 2008 GAAP earnings were impacted by net, non-cash, after-tax losses of approximately $204 million:
  - $1,193 million pre-tax ($723 million after-tax) ceiling test write down offset by…
  - $970 million pre-tax ($582 million after-tax) mark-to-market gain on derivatives
  - Resulted in recognition of a $63 million income tax valuation allowance
- Write-down does not affect our liquidity or compliance with bank covenants
- Since we do not designate our derivative financial instruments as hedges, we are not allowed to use the impacts of derivative financial instruments in our ceiling test computation
- Mark-to-market gain on derivatives would have been $1,167 million utilizing ceiling test prices
- At September 30, 2008 basis differentials were significantly more than their historic ranges, significantly impacting the ceiling test

Sales hub	Sept. 30, 2008 spot price	Sept. 30, 2008 differential to Henry Hub	Average YTD differential to Henry Hub	Sept. 30, 2008 deviation from average deferential
Henry Hub	$ 7.12	n/a	n/a	-
Houston Ship Channel	6.70	$ (0.42)	$ (0.31)	$ (0.11)
Panhandle Eastern Pipeline	3.69	(3.43)	(1.55)	(1.88)
Waha	4.81	(2.31)	(1.07)	(1.24)
Columbia	7.18	0.06	0.38	(0.32)
Dominion	7.15	0.03	0.54	(0.51)

Liquidity Update and Capital Spending Outlook

- Liquidity Update
  - On October 20, 2008, we received reaffirmation of our $2.5 billion borrowing base under our revolving credit agreements from our lenders
  - Currently in discussions with our lenders to refinance, renew and extend our $300 million Term Loan
  - Evaluating the sale of non-core assets
- Q4 2008 Capital Spending Outlook
  - Total capital expenditures expected to be approximately 35% lower than Q3 2008 levels
  - Savings realized from reduced rig count as well as the successful completion of our leasing and midstream expansion capital projects in Q3 2008
- 2009 Capital Spending Outlook
  - Finalizing 2009 capital spending plans; will maintain our strategy of spending within projected cash flow
  - 2009 capital budget focus will be on horizontal shale development, exploitation projects to minimize the base decline on our conventional properties, minimal leasing and continued development and expansion of our midstream assets to assure we have access to gas markets
  - Will maintain flexibility to increase spending if oil and natural gas prices improve
  - Believe we can maintain current production levels with a capital budget of $350 - $450 million

Third Quarter 2008
Liquidity and Financial Position

(in thousands)	September 30, 2008	November 3, 2008
Cash	$ 95,135	$ 53,130
Bank debt (LIBOR + 100 -175bps)	$ 2,232,485	$ 2,232,485
Senior notes (7 $^{1}/_{4}$%)(1)	444,720	444,720
Senior unsecured term loan	300,000	300,000
Total debt	$ 2,977,205	$ 2,977,205
Common shareholders' equity	2,486,628	
Total capitalization	$ 5,463,833	
Net debt to total capitalization	53%	
Borrowing base(2)	$ 2,475,000	$ 2,475,000
Unused borrowing base(3)	$ 238,015	$ 238,015
Unused borrowing base plus cash	$ 333,150	$ 291,145

- $2.5 billion combined borrowing bases reaffirmed on October 20, 2008
- Converted preferred stock into approximately 105 million shares of common stock on July 18, 2008, resulting in annual dividend savings of $140 million
- $700 million of interest rate swaps at an average LIBOR rate of 2.66%

(1) Excludes unamortized bond premium
(2) Reaffirmed as of October 20, 2008
(3) Net of $4.5 million in letters of credit at September 30, 2008 and November 3, 2008

Current Derivatives Position
November 3, 2008

NYMEX Swaps	Gas Mmcf	Contract price per Mmcf	Oil Mbbls	Contract price per Bbl	Percent Hedged[(1)]
Q4 2008	26,910	$ 8.39	450	$ 78.60	78%
2009	100,530	8.18	1,580	80.64	74%
2010	51,698	8.10	1,568	104.64	41%
2011 and after	12,780	6.98	1,187	112.70	-
Total	191,918	$ 8.11	4,785	$ 96.27	
	Total of 220,628 Mmcfe Hedged at $9.14				

- Target hedging 65-80% of production volumes for 3-5 years
- Hedging program covers long-term debt
- $700 million of interest rate swaps at an average LIBOR rate of 2.66%
- 2009 PEPL basis swaps; 3,650 Mmcf swapped at NYMEX minus $1.10

(1) Based on 2008 production guidance

Third Quarter 2008 Guidance vs. Actuals

	Third Quarter 2008		
($ in thousands, except per unit amounts)	Guidance: Low	Guidance: High	Actual
Production:			
Oil – Mbbls	500	510	590
Gas – Mmcf	33,300	34,200	33,017
Mmcfe	36,300	37,300	36,557
Per day – Mmcfe	395	405	397
Differentials to NYMEX:			
Oil per Bbl	($3.75)	($3.50)	($2.04)
Gas per Mcf	97%	100%	99%
Lease operating expense	$41,500	$44,500	$41,121
Stock based compensation - LOE	$750	$1,250	$1,169
Gathering expense – per Mcfe	$0.10	$0.15	$0.10
Production tax rate	6.0%	7.0%	5.1%
Other income	$250	$500	$1,820
Midstream revenue	$20,000	$25,000	$27,004
Midstream expense	$18,000	$22,500	$28,820
Midstream income	$2,000	$2,500	($1,816)
Depletion rate per Mcfe	$3.05	$3.15	$3.28
Depreciation rate per Mcfe	$0.15	$0.25	$0.18
Asset retirement obligation	$1,545	$1,795	$1,482
Cash G&A	$17,000	$18,000	$18,017
Non-cash stock comp	$2,070	$3,070	$2,985
Interest expense(1)	$45,300	$47,300	$42,659
Tax rate	40%	40%	40%
Cash tax rate	0%	0%	0%
Preferred dividends	$7,000	$7,000	$6,997
Adjusted EBITDA(2)	$227,300	$235,700	$248,870

(1) Does not include impact of fair market adjustment on interest rate swaps of $2,215
(2) Non-GAAP measure, please see tables on slides 28 to 32 for reconciliations to most comparable GAAP measures

Quarterly 2008 Guidance

($ in thousands, except per unit amounts)	9 Months Actual	4th Q 2008E Low	4th Q 2008E High	2008E[4] Low	2008E[4] High
Production:					
Oil - Mbbls	1,643	580	590	2,223	2,233
Gas - Mmcf	97,687	33,800	34,600	131,487	132,287
Mmcfe	107,545	37,300	38,200	144,845	145,745
Per day - Mmcfe	393	405	415	396	398
Differentials to NYMEX:					
Oil per Bbl	($2.15)	($3.75)	($3.50)	($2.57)	($2.51)
Gas per Mcf	99.9%	93.0%	98.0%	98.1%	99.4%
Lease operating expense	$112,797	$41,500	$44,500	$154,300	$157,300
Stock based compensation – LOE	$3,289	$2,390	$2,790	$5,680	$6,080
Gathering expense – per Mcfe	$0.10	$0.10	$0.15	$0.10	$0.11
Production tax rate	5.4%	5.5%	6.5%	5.4%	5.6%
Other income	$5,496	$250	$500	$5,750	$6,000
Midstream revenue	$105,916	$47,000	$51,000	$152,920	$156,920
Midstream expense	$79,000	$40,000	$43,000	$119,000	$122,000
Midstream income	$26,916	$7,000	$8,000	$33,920	$34,920
Depletion rate per Mcfe	$3.06	$2.75	$2.85	$2.98	$3.00
Depreciation rate per Mcfe	$0.17	$0.15	$0.25	$0.16	$0.19
Asset retirement obligation	$4,271	$1,545	$1,795	$5,820	$6,070
Cash G&A	$55,733	$18,000	$19,000	$73,730	$74,730
Non-cash stock comp	$7,553	$4,070	$6,070	$11,620	$13,620
Interest expense[1]	$106,322	$47,000	$49,000	$153,320	$155,320
Tax rate	39%	40%	40%	39%	39%
Cash tax rate	0%	0%	0%	0%	0%
Preferred dividends	$76,997	$0	$0	$76,997	$76,997
Fully diluted shares outstanding[2]		211,000	212,000		
Adjusted EBITDA at Midpoint[3]	$765,800	$232,400		$998,200	

(1) Includes $5.3 million of non-cash deferred financing cost amortization in Q3 and Q4 related to the senior unsecured term loan
(2) Fully diluted shares outstanding includes 105,263,158 shares in the third and fourth quarters resulting from the conversion of preferred stock on July 18, 2008
(3) 2008 estimates based on NYMEX $65 oil and $6.50 natural gas for the fourth quarter; non-GAAP measure
(4) 2008 guidance includes actual results for the first, second, and third quarters of 2008

EXCO Resources, Inc.

Operational Review

Hal Hickey

Operational Highlights
East Texas/North Louisiana – Haynesville Shale
Third Quarter 2008

- Acreage
  – Obtained shale acreage through leasing and acquisitions; securing acreage for horizontal development through trades and unit formations
- Vertical wells
  – Drilled eight vertical Haynesville wells in four counties / parishes to delineate the play and optimize completion methods; cored two wells
  – Averaged 200 feet of net pay in vertical wells drilled in Harrison County, TX and Caddo and DeSoto Parishes, LA; initial production rates ranged from 0.8 – 2.8 Mmcfe/d in single stage fracture stimulation at flowing pressures of 1,000 to 6,900 psi
- Horizontal wells
  – Drilled first operated horizontal well, the Oden 6H #1, in DeSoto Parish; successfully cut 180' feet of core
  – Oden 6H #1 has over 4,400' of lateral section; ran and cemented over 16,000' of 5½" by 4½" casing; plan to complete in November 2008 utilizing ten frac stages
  – TD'd our first non-operated horizontal well, in DeSoto Parish, with over 4,000' of lateral section
  – Will receive second of five new 1,500 hp top drive rigs in November 2008; all new build rigs will be received by 2Q 2009
  – Plan to spud two additional company operated (DeSoto Parish) and one additional outside operated (Caddo Parish) horizontal wells in Q4 2008

Operational Highlights
East Texas/North Louisiana
Third Quarter 2008

- Vernon
  - Drilled and completed seven gross (5.6 net) wells during Q3 with average IP of more than 4.7 Mmcfe/d gross (3.2 Mmcfe/d net)
  - Expanded southern and western field limits and number of drilling locations; reducing rig count from four to three in November
  - Reprocessing seismic as we evaluate 35,000 net prospective acres
  - While drilling costs rose through the first three quarters of 2008, costs are now moderating/decreasing
  - Currently running four pulling units; have completed 121 workover projects through Q3 YTD to help flatten base decline
  - Upgrading field compression from one to two stage, uplifting base volumes by decreasing well head pressures from an average of 375 psi to 175 psi

Operational Highlights

East Texas/North Louisiana
Third Quarter 2008

- Shreveport Area
  - Drilled and completed 25 wells (17 net) in Q3 with average IP of nearly 900 Mcfe/d
  - Continued to expand field limits at Holly/Caspiana
  - Spud to rig release time has continued to show improvement
  - Drilling several budgeted Cotton Valley wells to the deeper Haynesville to hold acreage and further define the play; as these wells are being completed in the Haynesville formation, some Cotton Valley completions are being deferred
  - Finalized salt water disposal contract
  - Maintaining six pulling units on workovers and recompletions to lower the base decline; completed 104 projects through end of 3Q 2008
  - Reducing drilling rig count from five to four

- East Texas Area
  - Initiated two rig drilling program in recently acquired Danville field
  - Opened data room on asset divestiture of Gladewater and Overton fields
  - Maintaining three pulling units on active workover / recompletion program to flatten base decline; completed 42 projects through Q3 2008
  - Performing micro seismic frac mapping at Danville to determine frac direction for future field development

Operational Highlights
Midstream Activity
Third Quarter 2008

- Throughput has increased from 460 Mmcf/d at year end 2007 to 555 Mmcf/d today
- 57-mile, $38 million expansion of our TGG pipeline completed in mid-August adding 215 Mmcf/d of capacity without compression; total system capacity of 390 Mmcf/d without compression
- Initial work has begun on the first phase of our Haynesville header pipeline system to enhance Haynesville takeaway capacity for both equity and third party production

Operational Highlights
Appalachia
Third Quarter 2008

- Production
  - Production for the quarter was 58 Mmcfe/d (currently at 60 Mmcfe/d)
    - 35% increase over Q3 2007
  - Artificial Lift Enhancements in Central Pennsylvania
    - Completed 63 pump jack & 26 plunger lift Installations through Q3 2008
    - 157% increase on pump jacks; 47% increase on plunger lift volumes

- Drilling
  - Achieved 100% drilling success on 52 gross (47.8 net) wells
  - Year-to-date achieved 99% drilling success on 107 gross (98.5 net) wells
  - Reduced rig count from 10 rigs drilling in late September to six - seven rigs drilling in November
  - Contracted new-build 1,000-horsepower top-drive rig for Q2 2009 delivery for Marcellus development

Operational Highlights
Appalachia
Third Quarter 2008

- Marcellus Shale
  - Currently drilling the third of our four well 2008 horizontal program
  - Completed two horizontal Marcellus wells in Pennsylvania
    - Four stage completion with 1,700’ lateral; flowed at a spot rate of 3.4 Mmcf/d
    - One stage completion with 500’ lateral; flowed at a spot rate of 1.0 Mmcf/d
  - Spud and completed six vertical Marcellus wells in West Virginia and Pennsylvania
    - Three are in the normal pressured areas and have initial rates of 70 – 100 Mcf/d
    - Three are in the over-pressured areas and are on initial flowback

- Huron Shale
  - Plan to drill 13 horizontal wells in 2008
    - Spud nine wells to date
    - Completed five wells
      - Spot rates have exceeded 400 Mcf/d, in line with expectations

- Fourth Quarter 2008 Shale Exploitation and Development Plans
  - Drill three additional vertical Marcellus wells
  - Drill four additional horizontal Huron wells in West Virginia

Operational Highlights

Other Areas
Third Quarter 2008

- Permian – Canyon Sand Field
  - Drilled 35 gross (32.1 net) wells in Q3 with three operated and one non-operated rig (97% success rate)
  - Plan to drill 121 gross (114.6 net) wells in 2008
  - Q3 2008 net production of 25 Mmcfe/d is up from less than 20 Mmcfe/d in November 2007, when EXCO took over operations; oil production up from 1,327 Bopd in November 2007 to more than 2,230 Bopd today
  - Will drill two wells in early 2009 to earn approximately 11,000 net contiguous acres
  - Leased additional 35,000 net acres contiguous to our existing acreage in Q3; now hold approximately 77,000 net acres in the area
  - Currently acquiring and evaluating 3-D seismic to identify additional opportunities
- Rockies
  - Plan to complete our previously drilled Birdseye prospect in the Wind River basin this month
- Mid-Continent
  - Set record production rate approaching 70 Mmcfe/d, driven primarily by recent drilling success in Golden Trend area
  - Drilled and completed 16 gross (10.0 net) wells in the Mid-Continent area achieving a 100% success rate; had four rigs running at end of Q3
  - Plan to drill 57 gross (33.0 net) wells in the Mid-Continent area during 2008

2008 Capital Spending and Activity Outlook

Q4 capital expenditures expected to be ~35% lower than Q3

- Capital spending

($ in millions)	Q1 - Q3	Q4 Estimate	2008 Total
East Texas/North Louisiana	$ 370	$ 94	$ 464
Appalachia	164	30	194
Mid-Continent	50	16	66
Permian/Rockies	84	29	113
Midstream	41	10	51
Other	40	13	53
Total	$ 749	$ 192	$ 941

- Q4 2008 reduced spending of $192 million is $115 million below our Q3 2008 spending level of $307 million; reduced expenditures result from our rig count decreasing from 32 to 25 as well as the successful completion of our leasing and midstream capital projects in Q3 2008

EXCO Resources, Inc.

Appendix

Operating Results

(in thousands)	Three months ended September 30, 2008	2007	% Change	Nine months ended September 30, 2008	2007	% Change
Revenues and other income:						
Oil	$ 68,456	$ 34,520	98%	$ 183,454	$ 75,682	142%
Natural gas	333,928	193,796	72%	972,524	534,545	82%
Midstream	27,004	4,432	509%	61,852	14,189	336%
Cash settlement on derivative instruments	(70,019)	46,249	(251)%	(157,383)	84,951	(285)%
Other income	1,820	2,417	(25)%	5,496	7,579	(27)%
Adjusted revenues[(1)]	361,189	281,414	28%	1,065,943	716,946	49%
Costs and expenses:						
Operating costs – Cash	$ 41,121	$ 29,342	40%	$ 112,797	$ 80,173	41%
Operating costs – Non-cash[(2)]	1,169	730	60%	3,289	1,497	120%
Production taxes	20,689	14,304	45%	61,432	39,679	55%
Production costs	62,979	44,376	42%	177,518	121,349	46%
Midstream operating expenses	28,820	4,236	580%	59,671	11,339	426%
Gathering and transportation costs	3,672	3,387	8%	10,503	6,662	58%
General and administrative – Cash	18,017	15,477	16%	55,733	40,944	36%
General and administrative – Non-cash[(2)]	2,985	1,533	95%	7,553	5,231	44%
Operating and production expenses	116,473	69,009	69%	310,978	185,525	68%
Depreciation, depletion and amortization	126,207	109,325	15%	346,705	265,797	30%
Accretion of discount on asset retirement obligations	1,482	1,324	12%	4,271	3,534	21%
Interest	44,874	36,523	23%	101,167	146,775	(31)%
Total costs and expenses	289,036	216,181	34%	763,121	601,631	27%
Non-cash adjustments and interest from above	176,717	149,434		462,985	422.834	
Adjusted EBITDA[(1)]	$ 248,870	$ 214,668	16%	$ 765,807	$ 538,149	42%

(1) Non-GAAP measure; please see table on slides 28 - 32 for reconciliation to most comparable GAAP measure
(2) Stock based compensation

Unit Operating Statistics

	Three months ended September 30, 2008	Three months ended September 30, 2007	% Change	Nine months ended September 30, 2008	Nine months ended September 30, 2007	% Change
Production volumes:						
Oil – Mbbls	590	475	24%	1,643	1,176	40%
Gas – Mmcf	33,017	31,608	4%	97,687	79,591	23%
Total - Mmcfe	36,557	34,458	6%	107,545	86,647	24%
Realized pricing[1]:						
Oil per Bbl	$ 116.03	$ 72.67	60%	$ 111.66	$ 64.36	73%
Gas per Mcf	10.11	6.13	65%	9.96	6.72	48%
Per Mcfe	11.01	6.63	66%	10.75	7.04	53%
Production costs per Mcfe:						
Operating costs[2]	$ 1.13	$ 0.85	33%	$ 1.05	$ 0.92	14%
Production taxes	0.57	0.42	36%	0.57	0.46	24%
Total production costs	$ 1.70	$ 1.27	34%	$ 1.62	$ 1.38	17%
Gathering and transportation costs	$ 0.10	$ 0.10	0%	$ 0.10	$ 0.08	25%
Cash operating margin	$ 9.21	$ 5.26	75%	$ 9.03	$ 5.58	62%
Effects of cash settlements on derivatives	(1.92)	1.34	(243)%	(1.46)	0.98	(249)%
Net cash operating margin	$ 7.29	$ 6.60	10%	$ 7.57	$ 6.56	15%

(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 three and nine months ended September 30, 2008 and $0.02 for the three and nine months ended September 30, 2007

Non-GAAP Reconciliations

Revenues and Adjusted Revenues

(in thousands)	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Oil and natural gas revenues, before derivative financial instruments	$ 402,384	$ 228,316	$ 1,155,978	$ 610,227
Cash settlements on derivative financial instruments	(70,019)	46,249	(157,383)	84,951
Subtotal, revenues including cash settlements on derivative financial instruments	332,365	274,565	998,595	695,178
Non-cash gain (loss) on oil and natural gas derivative financial instruments	970,332	52,003	53,849	(4,821)
Oil and natural gas revenues	1,302,697	326,568	1,052,444	690,357
Midstream revenues	27,004	4,432	61,852	14,189
Other income	1,820	2,417	5,496	7,579
Total revenues other income, GAAP	1,331,521	333,417	1,119,792	712,125
Elimination of non-cash oil and natural gas derivative financial instrument activity included in GAAP revenues	(970,332)	(52,003)	(53,849)	4,821
Adjusted revenues[1]	$ 361,189	$ 281,414	$ 1,065,943	$ 716,946

(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 revenues specifically exclude 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 September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Cash flow from operations, GAAP	$ 299,783	$ 211,172	$ 812,017	$ 380,298
Net change in working capital	(53,559)	(22,379)	(49,786)	35,318
Settlements of derivative financial instruments with a financing element	(34,405)	(4,342)	(96,504)	(8,020)
Cash flow from operations before changes in working capital, non-GAAP measure[(1)]	$ 211,819	$ 184,451	$ 665,727	$ 407,596

(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 September 30, 2008 Amount	Three months ended September 30, 2008 Per Share	Three months ended September 30, 2007 Amount	Three months ended September 30, 2007 Per Share	Nine months ended September 30, 2008 Amount	Nine months ended September 30, 2008 Per Share	Nine months ended September 30, 2007 Amount	Nine months ended September 30, 2007 Per Share
Net income (loss), GAAP	$ (146,329)		$ 56,462		$ (572,082)		$ 51,651	
Adjustments:								
Non-cash mark-to-market (gains) losses on oil and natural gas derivative financial instruments, before taxes	(970,332)		(52,003)		(53,849)		4,821	
Non-cash mark-to-market (gains) losses on interest rate derivative financial instruments, before taxes	2,215		-		(5,155)		-	
Non-cash write down of oil and natural gas properties	1,193,105		-		1,193,105		-	
Nonrecurring financing costs, before taxes	-		-		-		32,100	
Income taxes on above adjustments[1]	(89,995)		20,801		(453,640)		(14,768)	
Deferred tax asset valuation allowance	63,302		-		63,302		-	
Total adjustments, net of taxes	198,295		(31,202)		743,763		21,153	
Adjusted net income	$ 51,966		$ 25,260		$ 171,681		$ 73,804	
Net income (loss) available to common shareholders, GAAP[2]	$ (153,326)	$ (0.80)	$ 10,729	$ 0.10	$ (649,079)	$(4.84)	$ (46,317)	$(0.44)
Adjustments shown above	198,295	1.04	(31,202)	(0.30)	743,763	5.55	22,153	0.21
Dilution attributable to stock options[3]	-	(0.01)	-	-	-	(0.03)	-	-
Adjusted net income (loss) available to common shareholders	$ 44,969	$ 0.23	$ (20,473)	$(0.20)	$ 94,684	$ 0.68	$ (24,164)	$(0.23)
Common stock and equivalents used for earnings per share (EPS):								
Weighted average common shares outstanding		191,452		104,415		134,006		104,311
Dilutive stock options		5,321		-		4,834		-
Dilutive preferred stock		-		-		-		-
Shares used to compute dilutive EPS for adjusted net income (loss) available to common shareholders		196,773		104,415		138,840		104,311

(1) The assumed income tax rate is 40% for all periods.
(2) Per share amounts are based on weighted average number of common shares outstanding.
(3) Represents dilution per share attributable to common stock equivalents from in-the-money stock options for periods with adjusted net income available to common shareholders. None of the Preferred Stock, which was issued on March 30, 2007 and converted into common stock on July 18, 2008, was dilutive for any of the periods.

Non-GAAP Reconciliations

EBITDA and adjusted EBITDA reconciliations

(unaudited, in thousands)	Three months ended September 30, 2008	Three months ended September 30, 2007	Nine months ended September 30, 2008	Nine months ended September 30, 2007
Net income (loss)	$ (146,329)	$ 56,462	$ (572,082)	$ 51,651
Interest expense	44,874	36,523	101,167	146,775
Income tax expense (benefit)	(4,291)	60,774	(264,352)	58,843
Depreciation, depletion and amortization	126,207	109,325	346,705	265,797
EBITDA[1]	**20,461**	**263,084**	**(388,562)**	**523,066**
Accretion of discount on asset retirement obligations	1,482	1,324	4,271	3,534
Impairment of oil and natural gas properties	1,193,105	-	1,193,105	-
Non-cash change in fair value of derivative financial instruments	(970,332)	(52,003)	53,849	4,821
Stock based compensation expense	4,154	2,263	10,842	6,728
Adjusted EBITDA[1]	**$ 248,870**	**$ 214,668**	**$ 765,807**	**$ 538,149**
Interest expense[2]	(42,659)	(36,523)	(106,322)	(146,775)
Income tax benefit (expense)	4,291	(60,774)	264,352	(58,843)
Amortization of deferred financing costs, premium on 7¼% senior notes due 2011 and discount on long-term debt	5,710	884	6,527	10,800
Deferred income taxes	(4,413)	66,849	(264,657)	64,918
Changes in operating assets and liabilities and other	53,579	21,726	49,806	(35,971)
Settlements of derivative financial instruments with a financing element	34,405	4,342	96,504	8,020
Net cash provided by operating activities	$ 299,783	$ 211,172	$ 812,017	$ 380,298
Statement of cash flow data:				
Cash flow provided by (used in):				
Operating activities[2]	$ 299,783	$ 211,172	$ 812,017	$ 380,298
Investing activities	(550,979)	(55,886)	(1,485,137)	(2,028,552)
Financing activities	312,189	(61,770)	712,745	1,772,229

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.