

EXCO EXCO Resources, Inc.

Fourth Quarter 2008 Review

February 2009



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 use of derivative financial instruments; and
- our plans and forecasts.

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

We use the words "may," "expect," "anticipate," "estimate," "believe," "continue," "intend," "plan," "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;
- environmental or other governmental regulations, including legislation to reduce emissions of greenhouse gases;
- receipt and collectibility of amounts owed to us by purchasers of our production and counterparties to our derivative financial instruments;
- decisions whether or not to enter into derivative financial instruments;
- 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, 2008 which will be available on our website after February 26, 2009 at www.excoresources.com under the Investor Relations tab or by calling us at 214-368-2084.

EXCO EXCO Resources, Inc.

Financial Review

Steve Smith



Corporate Highlights

(in thousands, except per share and production)	Q4 2008		Q4 2007		2008		2007	
	Amount	Per Share	Amount	Per Share	Amount	Per Share	Amount	Per Share
Oil and natural gas revenues	\$ 248,840		\$ 265,560		\$ 1,404,826		\$ 875,787	
Cash settlements on oil and natural gas derivatives	\$ 48,083		\$ 23,462		\$ (109,300)		\$ 108,413	
Adjusted net income available to common shareholders ⁽¹⁾	\$ 27,512	\$ 0.13 ⁽⁴⁾	\$ 8,999	\$ 0.08 ⁽⁴⁾	\$ 129,115	\$ 0.82 ⁽⁴⁾	\$ (4,202)	\$ (0.04) ⁽⁴⁾
Adjusted EBITDA ⁽¹⁾	\$ 212,468		\$ 227,489		\$ 978,275		\$ 765,638	
Cash flow from operations ⁽¹⁾⁽²⁾	\$ 175,770	\$ 0.83 ⁽⁴⁾	\$ 192,158	\$ 0.91 ⁽⁴⁾	\$ 841,497	\$ 3.99 ⁽⁴⁾	\$ 599,754	\$ 2.83 ⁽⁴⁾
Average daily production – Mmcfe/d	403		377		395		332	
Midstream operating profit ⁽³⁾	\$ 8,016		\$ 5,872		\$ 34,931		\$ 23,487	

- Full year 2008 adjusted EBITDA was a record \$978 million; a 28% increase over 2007
- Successfully completed our first two horizontal Haynesville wells with IPs of 22.9 Mmcfe/d and 24.2 Mmcfe/d in Q4 2008 and Q1 2009, respectively
- Achieved record production rate of 395 Mmcfe/d for full year 2008; a 19% increase over 2007
- Completed 57-mile expansion of midstream intrastate pipeline in 2008; initiating construction of 29 mile, 36" diameter Haynesville header pipeline

(1) Non-GAAP measure, please see appendix for reconciliations to most comparable GAAP measures

(2) Cash flow from operations before changes in working capital and including settlements of derivative financial instruments with a financing element

(3) Includes intercompany items; see appendix for reconciliation

(4) Calculated using the following outstanding shares;

(shares in thousands)	Q4 2008	Q4 2007	2008	2007
Adjusted net income available to common shareholders	210,944	106,532	158,381	106,984
Cash flow from operations	210,944	210,895	210,949	212,247

Fourth Quarter 2008 Highlights

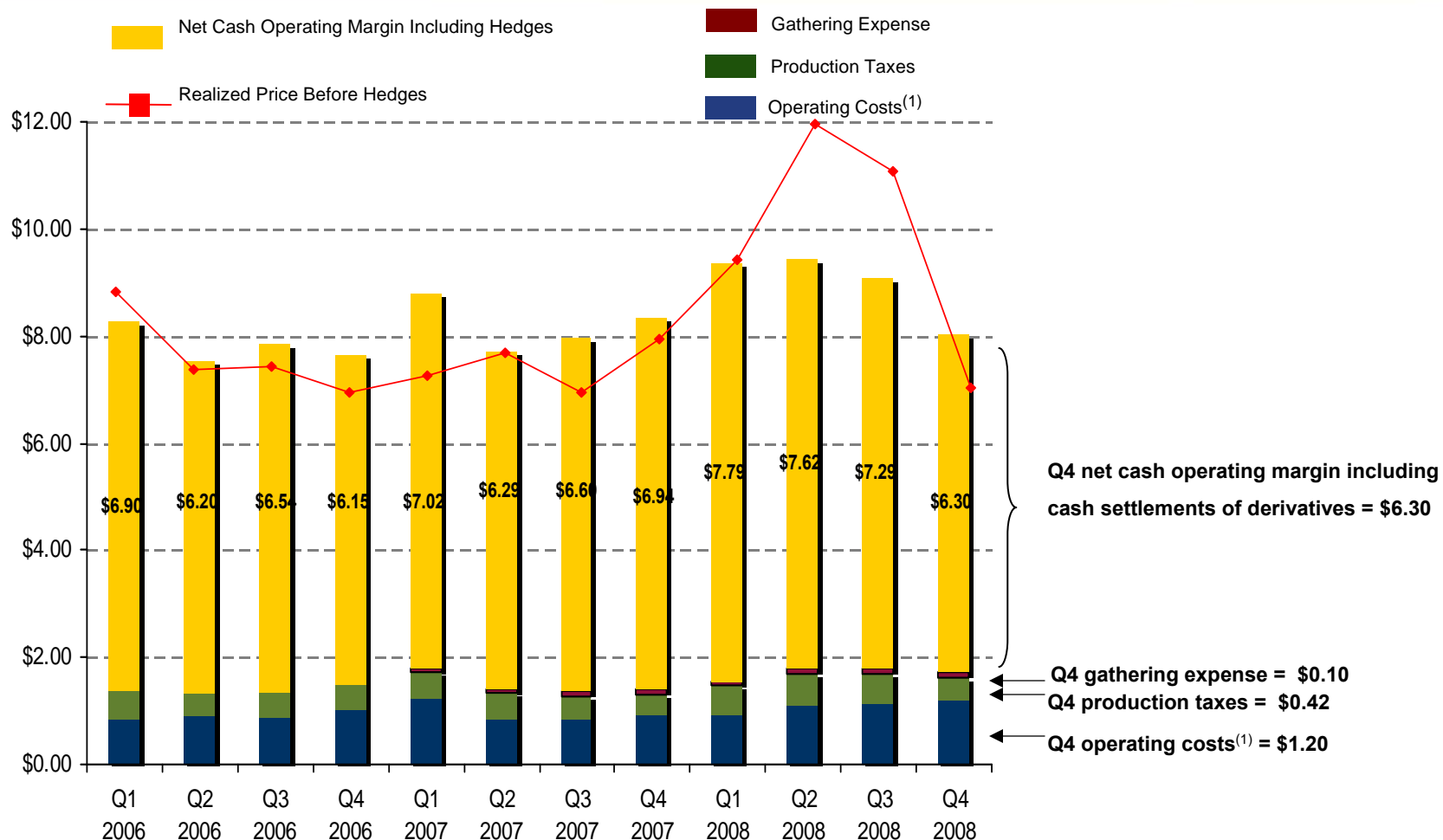


- Lower commodity price environment resulted in a reduction of rigs from 32 in Q3 2008 to 11 today; Q4 2008 total capital expenditures were 22% lower than Q3 2008
 - Accelerated Q4 2008 rig reduction plans; resulted in 33 fewer completions than Q3 2008 (down 23%), directly impacting production
- Have seen drilling costs and operating expenses decrease from peak levels; expect to see further reductions in 2009
 - Increased focus on workovers and exploitation projects in Q4 2008
- Haynesville activity update
 - Completed first horizontal well in Q4 2008 (Oden 30H #6) with an IP of 22.9 Mmcfe/d; produced 1.0 Bcf in 64 days; currently producing in excess of 12 Mmcfe/d on a 20/64th choke
 - Second horizontal well (Lattin 24 #4) turned to sales Q1 2009 with an IP of 24.2 Mmcfe/d on a 26/64th choke; producing approximately 20.0 Mmcfe/d on a 22/64th choke
 - Producing 35 Mmcfe/d (26 Mmcfe/d net) from the play
- Achieved recent midstream throughput record of approximately 600 Mmcf/d; moving forward with plans to construct 29 mile, 36” diameter pipeline to support Haynesville shale development to ensure access to multiple markets
- Refinanced \$300 million Senior Unsecured Term Loan in December 2008
- Asset divestiture program ongoing



Fourth Quarter 2008 Performance Highlights

Hedging program resulted in cash settlements of \$48 million in Q4 2008



(1) Does not include non-cash stock based compensation costs of \$0.02 per Mcfe for the fourth quarter 2008

2009 Capital Budget



- Board of Directors approved 2009 Capital Budget of up to \$582 million, down 41% from 2008 spending; drilling alone down 53% as we are planning to drill up to 186 wells vs. 475 in 2008

(dollars in millions)	2008 Capital Spending	2009 Budget	Δ
Drilling, completion and exploitation			
Conventional	\$ 582	\$ 126	\$ (456)
Unconventional / exploration	<u>111</u>	<u>200</u>	<u>89</u>
Total	693	326	(367)
Operations and other	16	69	53
Land	187	21	(166)
Midstream	55	141	86
Corporate and other	<u>38</u>	<u>25</u>	<u>(13)</u>
Total capital budget	\$ 989	\$ 582	\$ (407)

- Capital Budget is developed to;
 - Maintain our strategy of spending within projected cash flow while providing free cash flow for debt reduction
 - Focus on Haynesville Shale development; \$183 million dedicated to drilling and completion, \$124 million for midstream expansion and \$6 million for leasing
 - Positioning Marcellus for development in future years
 - Reduced drilling in other areas, except to honor rig and acreage commitments

2008 Non-Cash Items

Ceiling test write-downs

- 2008 GAAP earnings were impacted by net, non-cash, after-tax losses of approximately \$1.9 billion representing;
 - \$2.8 billion pre-tax (\$1.7 billion after-tax) ceiling-test write down, partially offset by \$484 million pre-tax (\$290 million after-tax) mark-to-market gain on derivatives, and a \$540 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
 - 2008 mark-to-market gain on derivatives would have been \$708 million utilizing ceiling test prices
- The following table presents details for each of the aforementioned significant non-cash items

(in millions)	Q4 2008	FY 2008
Pre-tax ceiling test write-downs	\$ (1,623)	\$ (2,816)
Non-cash gains on derivative financial instruments	425	484
Income tax benefit at 40%	479	933
Subtotal	(719)	(1,399)
Income tax valuation allowance ⁽¹⁾	(470)	(540)
Net non-cash after tax losses	\$ (1,189)	\$ (1,939)

(1) Deferred tax valuation allowance has been adjusted to reflect favorable impacts of adjustments

Liquidity and Financial Position



(dollars in thousands)	December 31, 2008	January 31, 2009
Cash	\$ 57,139	\$ 41,953
Bank debt (LIBOR + 100 -175bps)	\$ 2,267,436	\$ 2,302,349
Senior notes (7 1/4%) ⁽¹⁾	444,720	444,720
Senior unsecured term loan (10%) ⁽²⁾	<u>300,000</u>	<u>300,000</u>
Total debt	\$ 3,012,156	\$ 3,047,069
Common shareholders' equity	<u>1,332,501</u>	
Total capitalization	\$ 4,344,657	
Net debt to total capitalization	68%	
Borrowing base ⁽³⁾	\$ 2,475,000	\$ 2,475,000
Unused borrowing base ⁽⁴⁾	\$ 203,027	\$ 168,114
Unused borrowing base plus cash	\$ 260,166	\$ 210,067

- \$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) Due January 15, 2010. LIBOR plus 6% with LIBOR floor of 4%
(3) Reaffirmed as of October 20, 2008
(4) Net of \$4.5 million in letters of credit at December 31, 2008 and January 31, 2009

Current Derivatives Position

December 31, 2008



(in thousands, except price)	NYMEX natural gas Mmbtu	Contract price per Mmbtu	NYMEX oil Bbls	Contract price per Bbl	Percent hedged ⁽¹⁾	Contract price per Equivalent
Q1 2009	24,870	\$ 8.26	390	\$ 80.62	74%	\$ 8.71
Q2 2009	25,080	8.15	394	80.64	71%	8.61
Q3 2009	25,290	8.15	398	80.66	71%	8.61
Q4 2009	25,290	8.18	398	80.66	69%	8.63
2010	51,698	8.10	1,568	104.64	38%	9.54
2011	9,125	7.97	1,095	112.99	10%	12.52
2012	1,830	4.51	92	109.30	1%	7.69
2013	1,825	4.51	-	-	1%	4.51
Total	165,008	\$ 8.06	4,335	\$ 98.10		\$ 9.19

- Total of 191 Bcfe hedged at \$9.19 per Mcfe
- Target hedging 65-80% of production volumes for 3-5 years
- \$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 2009 production guidance

Fourth Quarter 2008 Guidance vs. Actuals



(dollars in thousands, except per unit amounts)	Fourth Quarter 2008		
	Guidance: Low	Guidance: High	Actual
<u>Production:</u>			
Oil - Mbbls	580	590	593
Gas - Mmcf	33,800	34,600	33,472
Mmcfe	37,300	38,200	37,030
Per day - Mmcfe	405	415	403
<u>Differentials to NYMEX:</u>			
Oil per Bbl	\$ (3.75)	\$ (3.50)	\$ (2.62)
Gas per Mcf	97.0%	100.0%	92.8%
Lease operating expense	\$ 41,500	\$ 44,500	\$ 44,191
Stock based compensation - LOE	\$ 2,390	\$ 2,790	\$ 885
Gathering expense - per Mcfe	\$ 0.10	\$ 0.15	\$ 0.10
Production tax rate	5.5%	6.5%	6.2%
Other income	\$ 250	\$ 500	\$ (1,515)
Midstream revenue	\$ 20,000	\$ 25,000	\$ 23,580
Midstream expense	\$ 19,000	\$ 23,500	\$ 23,126
Midstream income ⁽¹⁾	\$ 1,000	\$ 1,500	\$ 454
Depletion rate per Mcfe	\$ 2.75	\$ 2.85	\$ 2.88
Depreciation rate per Mcfe	\$ 0.15	\$ 0.25	\$ 0.19
Asset retirement obligation	\$ 1,545	\$ 1,795	\$ 2,432
Cash G&A	\$ 18,000	\$ 19,000	\$ 20,032
Non-cash stock comp	\$ 4,070	\$ 6,070	\$ 4,252
Interest expense ⁽²⁾	\$ 47,000	\$ 49,000	\$ 45,438
Tax rate	40%	40%	40%
Cash tax rate	0%	0%	0%
Full diluted shares outstanding	211,000	212,000	210,944
Adjusted EBITDA ⁽³⁾	\$232,400		\$ 212,468

- (1) Does not include intercompany items items. See page 32 for reconciliation
(2) Does not include impact of fair market adjustment on interest rate swaps of \$(15,033)
(3) Non-GAAP measure, please see appendix for reconciliations to most comparable GAAP measures

Quarterly 2009 Guidance



(dollars in thousands, except per unit amounts)	Q1 2009E		Q2 2009E		Q3 2009E		Q4 2009E	
	Low	High	Low	High	Low	High	Low	High
<u>Production:</u>								
Oil - Mbbls	535	545	500	510	495	505	485	495
Gas - Mmcf	32,800	34,100	34,800	36,100	35,200	36,500	36,200	38,400
Mmcfe	36,000	37,400	37,800	39,100	38,200	39,600	39,100	41,400
Per day - Mmcfe	400	415	415	430	415	430	425	450
<u>Differentials to NYMEX:</u>								
Oil per Bbl	\$ (3.75)	\$ (3.50)	\$ (3.75)	\$ (3.50)	\$ (3.75)	\$ (3.50)	\$ (3.75)	\$ (3.50)
Gas per Mcf	94.0%	99.0%	94.0%	99.0%	94.0%	99.0%	94.0%	99.0%
Lease operating expense	\$ 37,000	\$ 40,000	\$ 35,000	\$ 39,000	\$ 33,000	\$ 38,000	\$ 32,000	\$ 37,000
Stock based compensation - LOE	\$ 800	\$ 1,200	\$ 800	\$ 1,200	\$ 800	\$ 1,200	\$ 800	\$ 1,200
Gathering expense - per Mcfe	\$ 0.08	\$ 0.12	\$ 0.08	\$ 0.12	\$ 0.08	\$ 0.12	\$ 0.08	\$ 0.12
Production tax rate	6.0%	7.0%	6.0%	7.0%	5.5%	6.5%	5.5%	6.5%
Other income	\$ 250	\$ 500	\$ 250	\$ 500	\$ 250	\$ 500	\$ 250	\$ 500
Midstream revenue	\$ 18,500	\$ 19,500	\$ 19,000	\$ 21,000	\$ 23,000	\$ 27,000	\$ 23,000	\$ 27,000
Midstream expense	\$ 19,000	\$ 19,000	\$ 19,000	\$ 19,000	\$ 20,500	\$ 20,500	\$ 20,500	\$ 20,500
Midstream income ⁽¹⁾	\$ (500)	\$ 500	\$ -	\$ 2,000	\$ 2,500	\$ 6,500	\$ 2,500	\$ 6,500
Depletion rate per Mcfe	\$ 2.20	\$ 2.30	\$ 2.20	\$ 2.30	\$ 2.20	\$ 2.30	\$ 2.20	\$ 2.30
Depreciation rate per Mcfe	\$ 0.15	\$ 0.25	\$ 0.15	\$ 0.25	\$ 0.15	\$ 0.25	\$ 0.15	\$ 0.25
Asset retirement obligation	\$ 2,375	\$ 2,625	\$ 2,375	\$ 2,625	\$ 2,375	\$ 2,625	\$ 2,375	\$ 2,625
Cash G&A	\$ 19,000	\$ 21,000	\$ 19,000	\$ 21,000	\$ 19,000	\$ 21,000	\$ 19,000	\$ 21,000
Non-cash stock comp	\$ 2,750	\$ 3,250	\$ 2,750	\$ 3,250	\$ 2,750	\$ 3,250	\$ 3,750	\$ 5,250
Interest expense - cash	\$ 31,000	\$ 32,000	\$ 30,000	\$ 32,000	\$ 30,000	\$ 32,000	\$ 30,000	\$ 32,000
Interest expense - non-cash	\$ 12,000	\$ 15,000	\$ 12,000	\$ 15,000	\$ 12,000	\$ 15,000	\$ 12,000	\$ 15,000
Tax rate	40%	40%	40%	40%	40%	40%	40%	40%
Cash tax rate	0%	0%	0%	0%	0%	0%	0%	0%
CAPEX	\$ 160,000	\$ 180,000	\$ 160,000	\$ 170,000	\$ 92,000	\$ 101,000	\$ 92,000	\$ 109,000
Full diluted shares outstanding	211,000	212,000	211,500	212,500	212,000	213,000	212,500	213,500
Adjusted EBITDA at midpoint ⁽²⁾	\$ 208,000		\$ 216,800		\$ 225,300		\$ 233,800	

(1) Does not include intercompany items. Gross midstream income is expected to be \$50 million to \$60 million for the full year

(2) 2009 estimates based on NYMEX \$45.00 oil and \$5.50 natural gas for the year

EXCO EXCO Resources, Inc.

Operational Review

Hal Hickey



Operational Highlights

Fourth Quarter 2008 Results



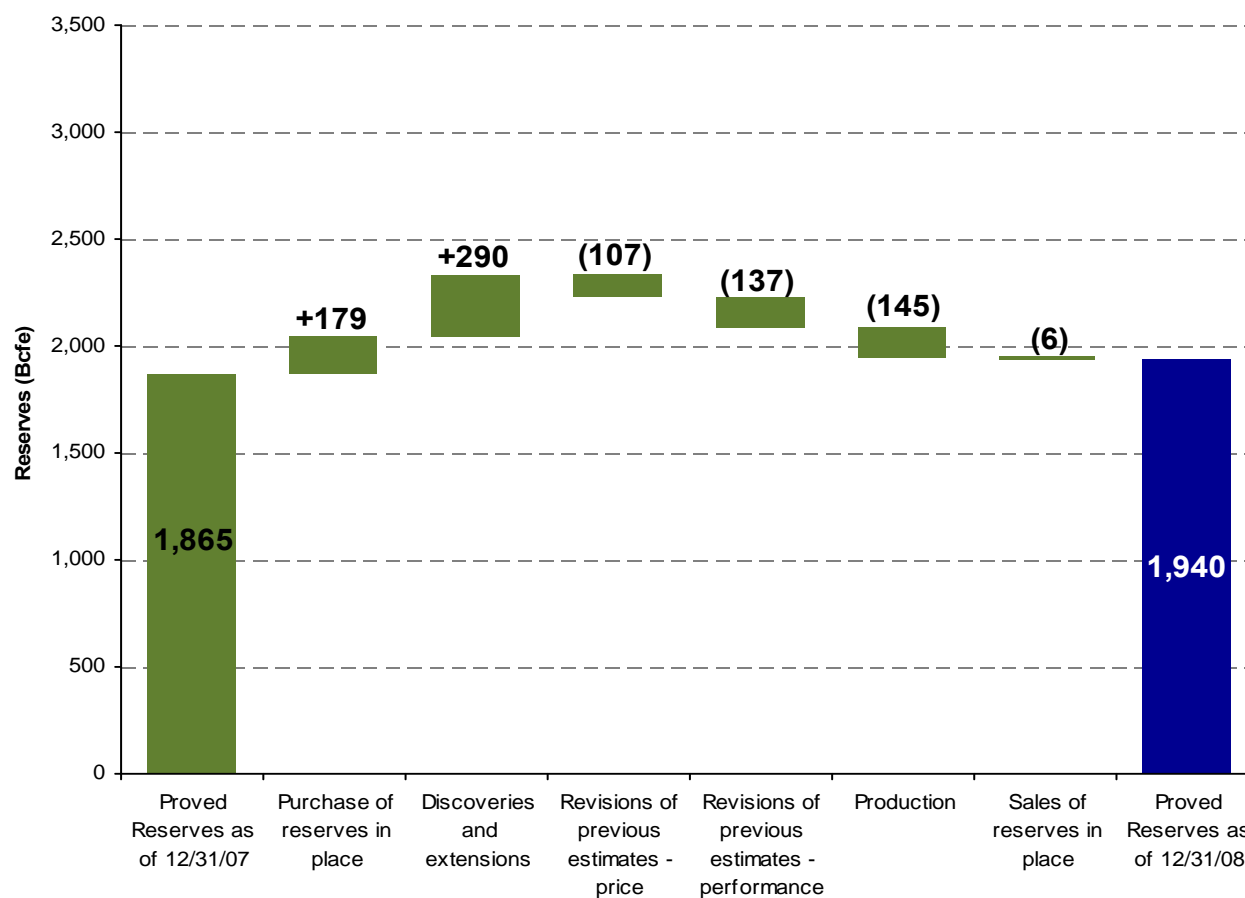
- Drilled 475 gross wells and completed 467 (98% success rate) during full year 2008, adding 290 Bcfe of proved reserves through drilling
- Realized record production of 145 Bcfe for full year 2008, versus 2007 production of 121 Bcfe
- Enhanced our position in two important shale plays, positioning the company for both short and long-term growth
- Acreage position increased from 1,498,129 net acres at YE 2007 to 1,814,588 net acres at YE 2008
 - Haynesville shale 92,000 net acres
 - Marcellus shale 395,000 net acres

Operational Highlights

Year End Total Proved Reserves



- Reserves increased from 1,865 Bcfe at 12/31/07 to 1,940 Bcfe at 12/31/08; however, using new SEC average price methodology effective 12/31/09, reserves would have been 2,253 Bcfe



Year End Total Proved Reserves



	Equivalent natural gas (Bcfe)
Proved developed	1,444
Proved undeveloped	496
Total	1,940
The changes in reserves for the year are as follows:	
December 31, 2007	1,865
Purchase of reserves in place	179
Extensions and discoveries	290
Revisions of previous estimates	
Change in price	(107)
Changes other than price	(137)
Production	(145)
Sales of reserves in place	(6)
December 31, 2008	1,940

	2008	3 Year
Reserve replacement:		
All-in ⁽¹⁾	230%	651%
Drill-bit only ⁽²⁾	201%	183%
Reserve replacement cost:		
All-in ⁽¹⁾	\$3.90	\$2.77
Drill-bit only ⁽²⁾	\$2.39	\$2.32

- (1) All-in reserve replacement is calculated using extensions and discoveries, acquisitions and revisions other than price. Total revisions were 245 Bcfe consisting of 138 Bcfe of negative revisions other than price and 107 Bcfe of revisions due to price decreases. Costs include drilling and development, exploration and acquisitions of proved properties.
- (2) Drill-bit only reserve replacement is calculated using extensions and discoveries. Costs include drilling and development and exploration costs.

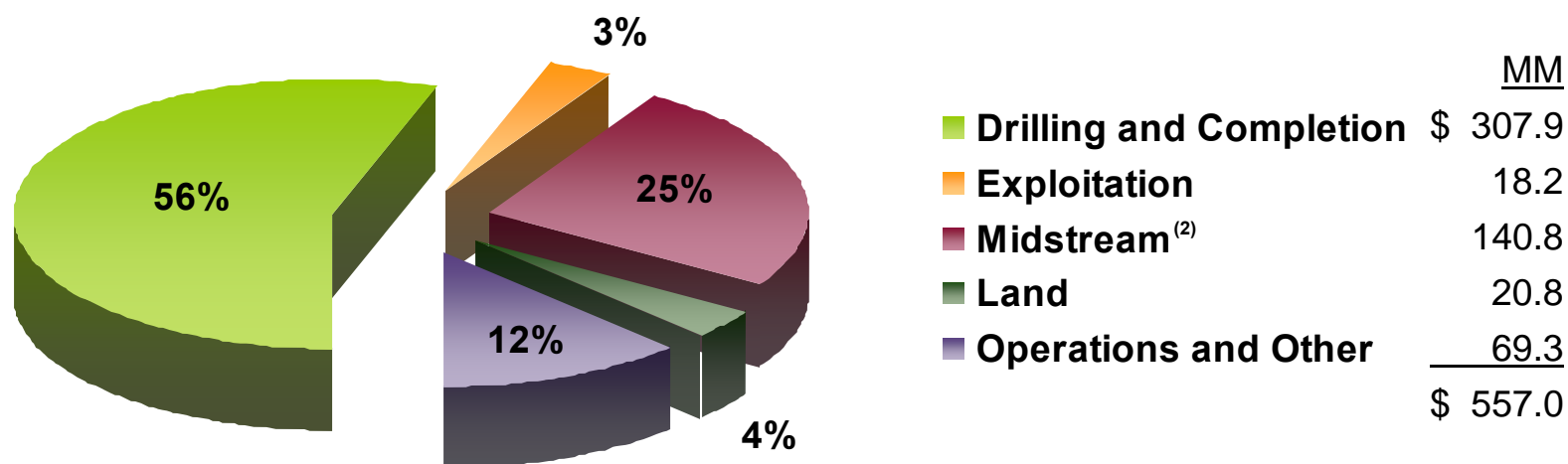
2009 Focus



- Manage spending in low commodity price environment, while protecting our acreage and reserves position and meeting our commitments
- Focus on opportunities that provide growth and strong returns
 - Continue delineating and developing Haynesville shale
 - Evaluate Bossier shale
 - High-grade Marcellus acreage in preparation for 2010 program
 - Limit non-shale drilling to high graded locations; will satisfy existing drilling and acreage commitments
 - Expand midstream in East Texas / North Louisiana and Appalachia
- Initiating asset divestiture program in early Q2 2009; plan to sell certain non-core assets in each of our divisions. Have engaged 3rd party brokers to manage process

Operational Highlights

Capital Budget Totals \$557.0 Million⁽¹⁾



2009 Capital Program

Area	Gross Wells	Drilling & Completion (Net \$ MM)			Exploitation (Net \$ MM)	Midstream (Net \$ MM)	Land (Net \$ MM)	Operations & Other (Net \$ MM)	Total 2009 Capital Budget (Net \$ MM) ⁽¹⁾
		Operated	OBO	Total					
East Texas/North Louisiana									
Cotton Valley	30	\$ 33.7	\$ 7.9	\$ 41.6	\$ 11.5	\$ 7.4	\$ 6.0	\$ 35.7	\$ 102.2
Haynesville/Bossier Shale	34	167.9	14.9	182.8	-	123.9	6.6	-	313.3
	64	201.6	22.8	224.4	11.5	131.3	12.6	35.7	415.5
Appalachia									
Conventional	53	13.3	-	13.3	2.8	-	0.9	11.2	28.2
Marcellus/Huron Shale	5	16.9	-	16.9	-	9.5	6.2	14.1	46.7
	58	30.2	-	30.2	2.8	9.5	7.1	25.3	74.9
Midcontinent									
Permian/Rockies	24	18.3	5.0	23.3	3.2	-	0.4	3.7	30.6
	40	30.0	-	30.0	0.7	-	0.7	4.6	36.0
Total	186	\$ 280.1	\$ 27.8	\$ 307.9	\$ 18.2	\$ 140.8	\$ 20.8	\$ 69.3	\$ 557.0

(1) Excludes \$24.6 million of IT and other capitalized items

(2) Midstream includes \$131.3 million in East Texas/North Louisiana (\$107.6 million for Haynesville Header) and \$9.5 million in Appalachia

Operational Highlights

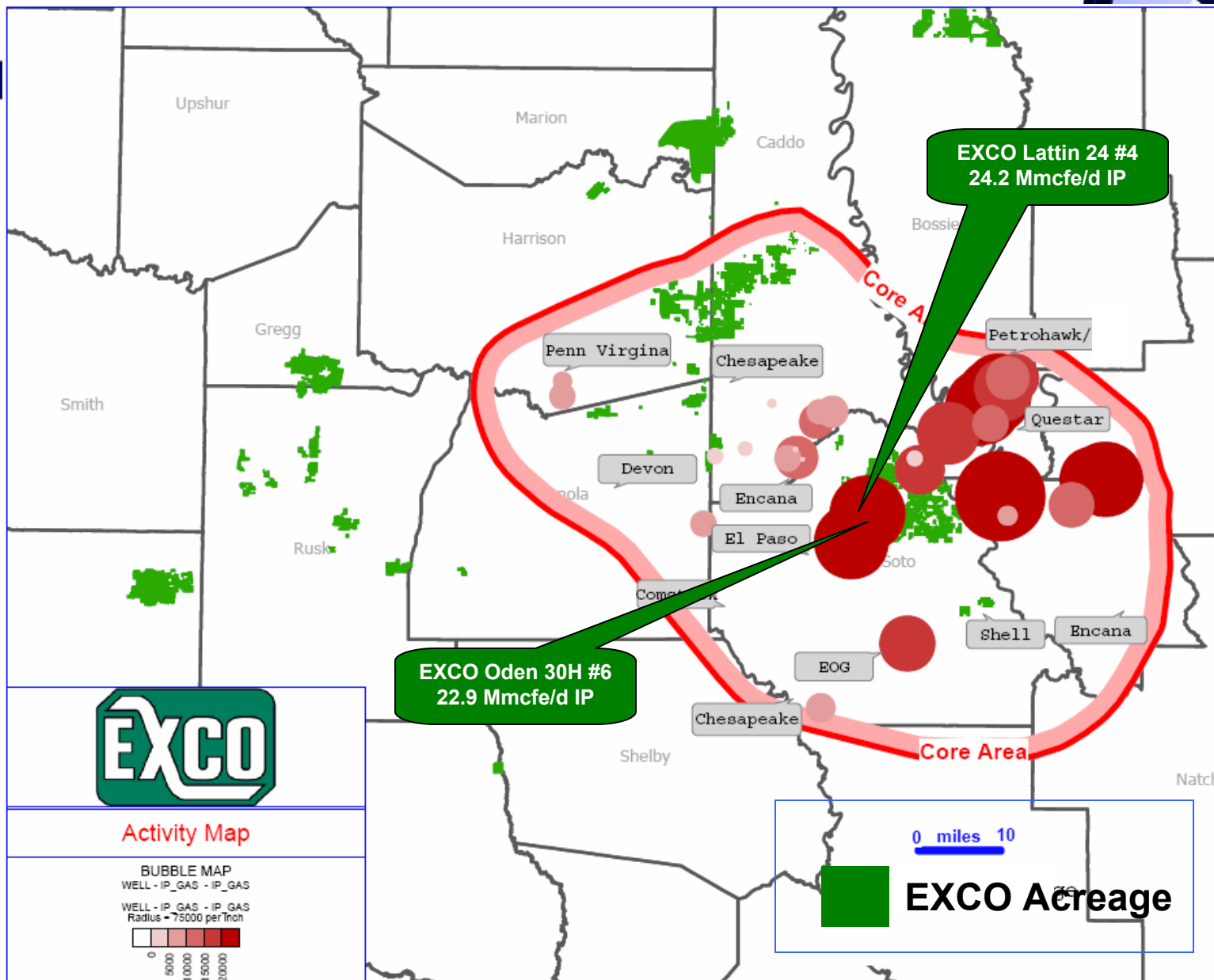
Haynesville Shale



- Haynesville Horizontal Results
 - Two horizontal wells completed with IPs of 22.9 and 24.2 Mmcfe/d on restricted chokes; two wells waiting on completion
 - Four operated rigs drilling; three non-operated rigs drilling
- Technical initiative yielding exceptional results
 - Shifted focus from traditional Cotton Valley to Haynesville development
 - Spent four months drilling and testing vertical wells to characterize rock properties, define play limits and refine frac designs
 - First horizontal well is among the best in the play; second horizontal well is performing similarly to the first
 - Producing 35 Mmcfe/d (gross) from the play less than 10 months after initial Haynesville play announcement
- Positioned for growth
 - Acreage – 92,000 acres with substantial HBP
 - Location – core area with existing operations
 - Potential – 4.5 Tcfe of resources
 - Significant reserve adds expected during 2009
- 2009 Plan
 - Drill 34 horizontal wells (27 operated)

Operational Highlights

Haynesville Horizontal Announced IP Map





Operational Highlights

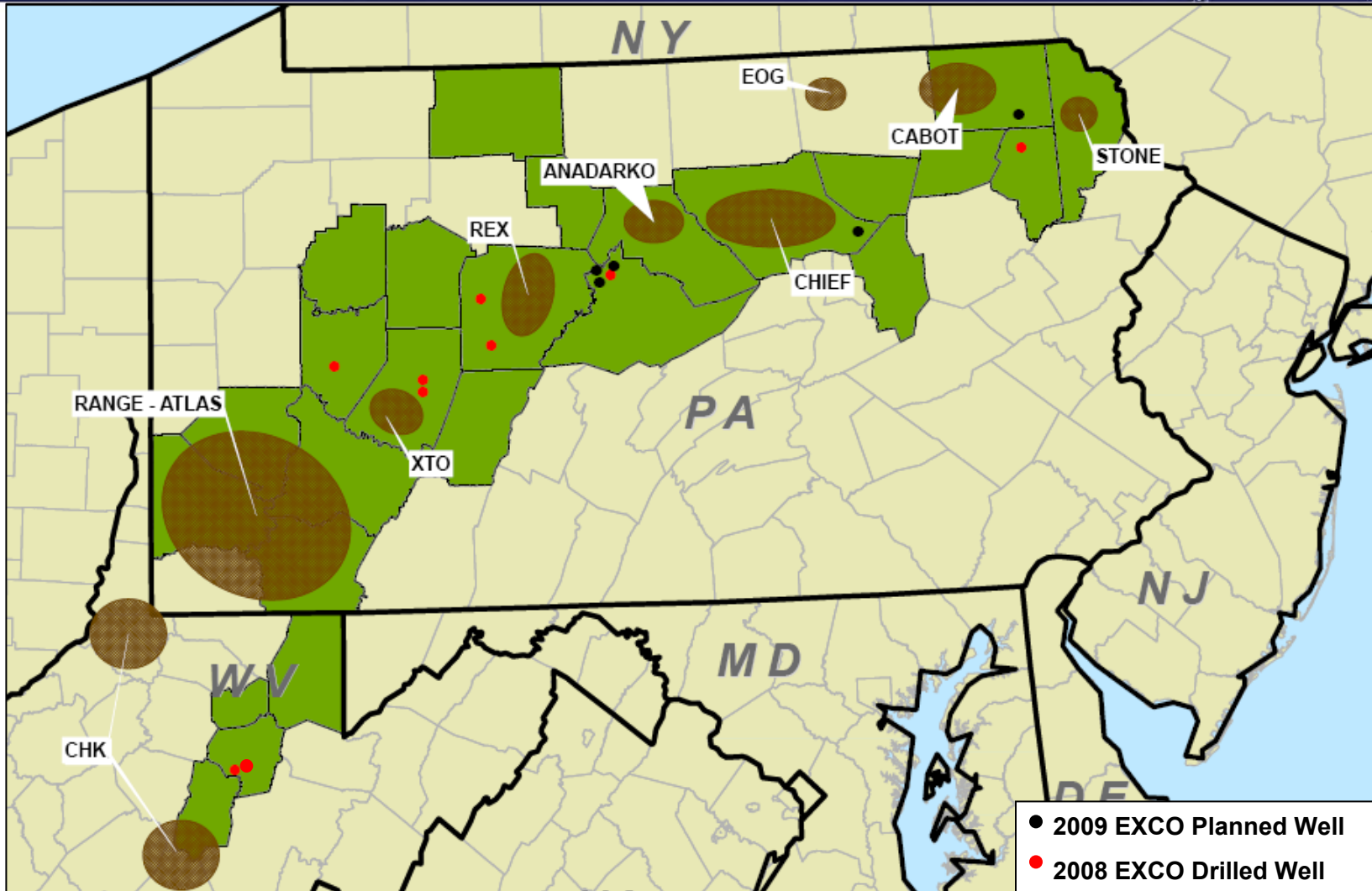
Marcellus Shale

- Marcellus Horizontal Results
 - Completed two horizontal Marcellus wells in Pennsylvania
 - Shortened lateral lengths of 500' and 1,700' due to geological issues, with rates from 1.0 to 3.4 Mmcf/d from one stage and four stage fracs
 - Interpreting recently shot seismic for improved reservoir description
 - Drilled two horizontal Marcellus wells in Northern West Virginia
 - Lateral lengths of 1,592' and 2,710', with plans for 4 and 7 stage completions, respectively, by Q2 2009
- 395,000 net acres spread across the play
 - Added approximately 60,000 new acres across the play in 2008
 - 249,000 acres in core, over-pressured areas
 - Drilled and completed six vertical wells across acreage, took cores and now prioritizing areas based on net pay, access to transportation, permitting, and other factors; three additional vertical wells to be completed in Q1 2009
- 2009 Plans
 - Budgeting two verticals and three horizontals for 2009 drilling
 - Shooting seismic and high-grading opportunities for late 2009 / early 2010 development



Operational Highlights

Marcellus Shale Activity



Operational Highlights

Midstream Activity



- Throughput has increased from approximately 460 Mmcf/d at year end 2007 to 575 - 600 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 \$108 million Haynesville header pipeline system to enhance Haynesville takeaway capacity for both equity and third party production; design capacity of 450 Mmcf/d expandable to >1.0 Bcf/d through compression

Appendix



Operating Results

(in thousands)	Three months ended December 31,		% change	Twelve months ended December 31,		% change
	2008	2007		2008	2007	
Revenues: (excludes derivatives)						
Oil	\$ 33,273	\$ 41,391	-20%	\$ 216,727	\$ 117,073	85%
Natural gas	215,567	224,169	-4%	1,188,099	758,714	57%
Midstream	23,580	4,628	410%	85,432	18,817	354%
Total operating revenues	272,420	270,188	1%	1,490,258	894,604	67%
Costs and expenses:						
Oil and natural gas production cost – cash	59,660	45,556	31%	233,897	165,408	41%
Oil and natural gas production cost – non-cash ⁽¹⁾	885	2,094	-58%	4,174	3,591	16%
Gathering and transportation	3,703	3,548	4%	14,206	10,210	39%
Midstream operating expense	23,126	4,950	367%	82,797	16,289	408%
General and administrative – cash	20,030	14,684	36%	75,763	55,629	36%
General and administrative – non-cash ⁽¹⁾	4,252	3,811	12%	11,805	9,041	31%
Total operating costs and expenses	111,656	74,643	50%	422,642	260,168	62%
Depreciation, depletion and amortization	113,609	109,623	4%	460,314	375,420	23%
Write-down of oil and natural gas properties	1,622,730	-	-	2,815,835	-	-
Accretion of discount on asset retirement obligations	2,432	1,344	81%	6,703	4,878	37%
Total costs and expenses	1,850,427	185,610	897%	3,705,494	640,466	479%
Operating income (loss)	(1,578,007)	84,578	-1966%	(2,215,236)	254,138	-972%
Other income (expense):						
Interest expense	(60,471)	(34,575)	75%	(161,638)	(181,350)	-11%
Gain (loss) on derivative financial instruments – cash	48,083	23,462	105%	(109,300)	108,413	-201%
Gain (loss) on derivative financial instruments – non-cash	439,840	(76,785)	-673%	493,689	(81,606)	-705%
Other income	(1,515)	2,578	-159%	3,981	10,157	-61%
Total other income (expense)	425,937	(85,320)	-599%	226,732	(144,386)	-257%
Income (loss) before income tax	(1,152,070)	(742)	155165%	(1,988,504)	109,752	-1912%
Adjusted EBITDA ⁽²⁾	212,468	227,489	-7%	978,275	765,638	28%

(1) Represents stock based compensation

(2) Non-GAAP measure; please see appendix for reconciliation to most comparable GAAP measure

Unit Operating Statistics



	December 31		%	December 31		%
	2008	2007		2008	2007	
<u>Production volumes:</u>						
Oil – Mbbls	593	469	26%	2,236	1,645	36%
Gas – Mmcf	33,472	31,828	5%	131,159	111,419	18%
Total - Mmcfe	37,030	34,642	7%	144,575	121,289	19%
Mmcfe/d	403	377	7%	395	332	19%
<u>Realized pricing⁽¹⁾:</u>						
Oil per Bbl	\$ 56.11	\$ 88.25	-36%	\$ 96.93	\$ 71.17	36%
Gas per Mcf	6.44	7.04	-9%	9.06	6.81	33%
Per Mcfe	6.72	7.67	-12%	9.72	7.22	35%
<u>Production costs per Mcfe:</u>						
Operating costs ⁽²⁾	\$ 1.20	\$ 0.93	29%	\$ 1.08	\$ 0.92	17%
Production taxes	0.42	0.39	8%	0.53	0.44	20%
Total production costs	\$ 1.62	\$ 1.32	23%	\$ 1.61	\$ 1.36	18%
Gathering and transportation costs	\$ 0.10	\$ 0.10	0%	\$ 0.10	\$ 0.08	25%
Cash operating margin	\$ 5.00	\$ 6.25	-20%	\$ 8.01	\$ 5.78	39%
Effects of cash settlements on derivatives	1.30	0.68	92%	(0.76)	0.89	-185%
Net cash operating margin	\$ 6.30	\$ 6.93	-9%	\$ 7.25	\$ 6.67	9%

(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 \$0.02 and \$0.03 for the three and twelve months ended December 31, 2008 and \$0.06 and \$0.03 for the three and twelve months ended December 31, 2007

Year End Total Proved Reserves



Our proved reserves, using December 31, 2008 spot prices, on a constant price basis, of \$5.71 per Mmbtu and \$44.60 per Bbl were as follows:

	Oil (Mbbbls)	Natural gas (Mmcfe)	Equivalent natural gas (Mmcfe)
Proved developed	14,815	1,354,729	1,443,619
Proved undeveloped	5,986	460,409	496,325
Total	20,801	1,815,138	1,939,944
The changes in reserves for the year are as follows:			
December 31, 2007	20,930	1,739,550	1,865,130
Purchase of reserves in place	635	175,679	179,489
Extensions and discoveries	5,040	259,801	290,041
Revisions of previous estimates			
Changes in price	(2,407)	(93,015)	(107,457)
Changes other than price	(1,060)	(130,605)	(136,965)
Sales of reserves in place	(101)	(5,113)	(5,719)
Production	(2,236)	(131,159)	(144,575)
December 31, 2008	20,801	1,815,138	1,939,944

(dollars in thousands, except per Mcfe)	Cost	(Mmcfe)	Per Mcfe
Development and exploration ⁽¹⁾	\$ 693,173	290,041	\$ 2.39
Proved property acquisition	604,723	179,489	3.37
Revisions - other than price ⁽²⁾	-	(136,965)	-
Subtotal	1,297,896	332,565	3.90
Revisions - price	-	(107,457)	-
Sales of reserves in place	(15,543)	(5,719)	-
Total ⁽³⁾	\$ 1,297,896	225,108	\$ 5.77

(1) Includes \$111.4 million of exploration costs; \$103.4 million related to the Haynesville and Marcellus shales

(2) Primarily consists of adjustments related to prior year acquisitions

(3) Does not include \$187.1 million of lease acquisition costs, \$87.2 million of unproved property acquisitions and \$19.2 million of capitalized asset retirement costs

Non-GAAP Reconciliations



Adjusted Net Income

(in thousands, except per share amounts)	Three months ended December 31, 2008		Three months ended December 31, 2007		Twelve months ended December 31, 2008		Twelve months ended December 31, 2007	
	Amount	Per Share	Amount	Per Share	Amount	Per Share	Amount	Per Share
Net income (loss), GAAP	\$ (1,161,389)		\$ (1,995)		\$ (1,733,471)		\$ 49,656	
Adjustments:								
Non-cash mark-to-market (gains) losses on derivative financial instruments, before taxes	(424,807)		76,785		(483,811)		81,606	
Non-cash write down of oil and natural gas properties	1,622,730		-		2,815,835		-	
Nonrecurring financing costs, before taxes	-		-		-		32,100	
Income taxes on above adjustments ⁽¹⁾	(479,169)		(30,791)		(932,810)		(45,596)	
Deferred tax asset valuation allowance ⁽²⁾	470,147		-		540,369		11,000	
Total adjustments, net of taxes	1,188,901		45,994		1,939,583		79,110	
Adjusted net income	\$ 27,512		\$ 43,999		\$ 206,112		\$ 128,766	
Net income (loss) available to common shareholders, GAAP ⁽³⁾	\$ (1,161,389)	\$ (5.51)	\$ (36,995)	\$ (0.35)	\$ (1,810,468)	\$ (11.81)	\$ (83,312)	\$ (0.80)
Adjustments shown above	1,188,901	5.64	45,994	0.44	1,939,583	12.65	79,110	0.76
Dilution attributable to stock options ⁽⁴⁾	-	-	-	(0.01)	-	(0.02)	-	-
Adjusted net income (loss) available to common shareholders	\$ 27,512	\$ 0.13	\$ 8,999	\$ 0.08	\$ 129,115	\$ 0.82	\$ (4,202)	\$ (0.04)
<u>Common stock and equivalents used for earnings per share (EPS):</u>								
Weighted average common shares outstanding		210,944		104,522		153,346		104,364
Dilutive stock options		-		2,010		5,035		2,620
Dilutive preferred stock		-		-		-		-
Shares used to compute dilutive EPS for adjusted net income (loss) available to common shareholders		210,944		106,532		158,381		106,984

(1) The assumed income tax rate is 40% for all periods.

(2) Deferred tax valuation allowance has been adjusted to reflect favorable impacts of adjustments.

(3) 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



Cash Flow From Operations

(in thousands)	Three months ended December 31,		% change	Twelve months ended December 31,		% change
	2008	2007		2008	2007	
Cash flow from operations, GAAP	\$ 162,949	\$ 197,531		\$ 974,966	\$ 577,829	
Net change in working capital	(80)	821		(49,866)	36,139	
Settlements of derivative financial instruments with a financing element	12,901	(6,194)		(83,603)	(14,214)	
Cash flow from operations before changes in working capital, non-GAAP measure ⁽¹⁾	<u>\$ 175,770</u>	<u>\$ 192,158</u>	-9%	<u>\$ 841,497</u>	<u>\$ 599,754</u>	40%

- (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.

Oil and gas derivative financial instruments

(in thousands)	Three months ended December 31,		Twelve months ended December 31,	
	2008	2007	2008	2007
Cash settlements from oil and natural gas derivative financial instruments				
Oil - cash settlements	\$ 8,933	\$ (9,882)	\$ (38,765)	\$ (13,242)
Natural gas - cash settlements	39,150	33,344	(70,535)	121,655
Total cash settlements	<u>48,083</u>	<u>23,462</u>	<u>(109,300)</u>	<u>108,413</u>
Non-cash change in fair market value of oil and natural gas derivative financial instruments	439,840	(76,785)	493,689	(81,606)
Gain/(loss) on oil and natural gas derivative financial instruments	<u>\$ 487,923</u>	<u>\$ (53,323)</u>	<u>\$ 384,389</u>	<u>\$ 26,807</u>

Non-GAAP Reconciliations



Midstream Operating Segment

(in thousands)	Three months ended December 31,		Twelve months ended December 31,	
	2008	2007	2008	2007
Midstream operations:				
Midstream revenues (before intersegment eliminations)	\$ 41,721	\$ 12,160	\$ 147,636	\$ 45,763
Midstream expenses (before intersegment eliminations)	33,705	6,288	112,705	22,276
Midstream operating profit (before intersegment eliminations)	8,016	5,872	34,931	23,487
Intersegment eliminations	(7,562)	(6,194)	(32,296)	(20,959)
Midstream operating profit (after intersegment eliminations)	454	(322)	2,635	2,528

Non-GAAP Reconciliations



EBITDA and adjusted EBITDA reconciliations

(in thousands)	Three months ended December 31,		Twelve months ended December 31,	
	2008	2007	2008	2007
Net income (loss)	\$ (1,161,389)	\$ (1,995)	\$ (1,733,471)	\$ 49,656
Interest expense, net	60,471	34,575	161,638	181,350
Income tax expense (benefit)	9,319	1,253	(255,033)	60,096
Depreciation, depletion and amortization	113,609	109,623	460,314	375,420
EBITDA ⁽¹⁾	(977,990)	143,456	(1,366,552)	666,522
Accretion of discount on asset retirement obligations	2,432	1,344	6,703	4,878
Non-cash write-down of oil and natural gas properties	1,622,730	-	2,815,835	-
Non-cash change in fair value of oil and natural gas derivative financial instruments	(439,840)	76,785	(493,689)	81,606
Stock based compensation expense	5,136	5,904	15,978	12,632
Adjusted EBITDA ⁽¹⁾	\$ 212,468	\$ 227,489	\$ 978,275	\$ 765,638
Interest expense, net ⁽²⁾	(45,438)	(34,575)	(151,760)	(181,350)
Income tax expense	(9,319)	(1,253)	255,033	(60,096)
Amortization of deferred financing costs, premium on 7¼% senior notes due 2011 and discount on long-term debt	8,668	(468)	15,195	10,332
Deferred income taxes	9,372	1,253	(255,285)	66,171
Changes in operating assets and liabilities	99	(1,109)	49,905	(37,080)
Settlements of derivative financial instruments with a financing element	(12,901)	6,194	83,603	14,214
Net cash provided by operating activities	\$ 162,949	\$ 197,531	\$ 974,966	\$ 577,829
Statement of cash flow data:				
Cash flow provided by (used in):				
Operating activities	\$ 162,949	\$ 197,531	\$ 974,966	\$ 577,829
Investing activities	(223,442)	(367,885)	(1,708,579)	(2,396,437)
Financing activities	22,497	79,067	735,242	1,851,296

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.