LINN Energy

NASDAQ:LINE

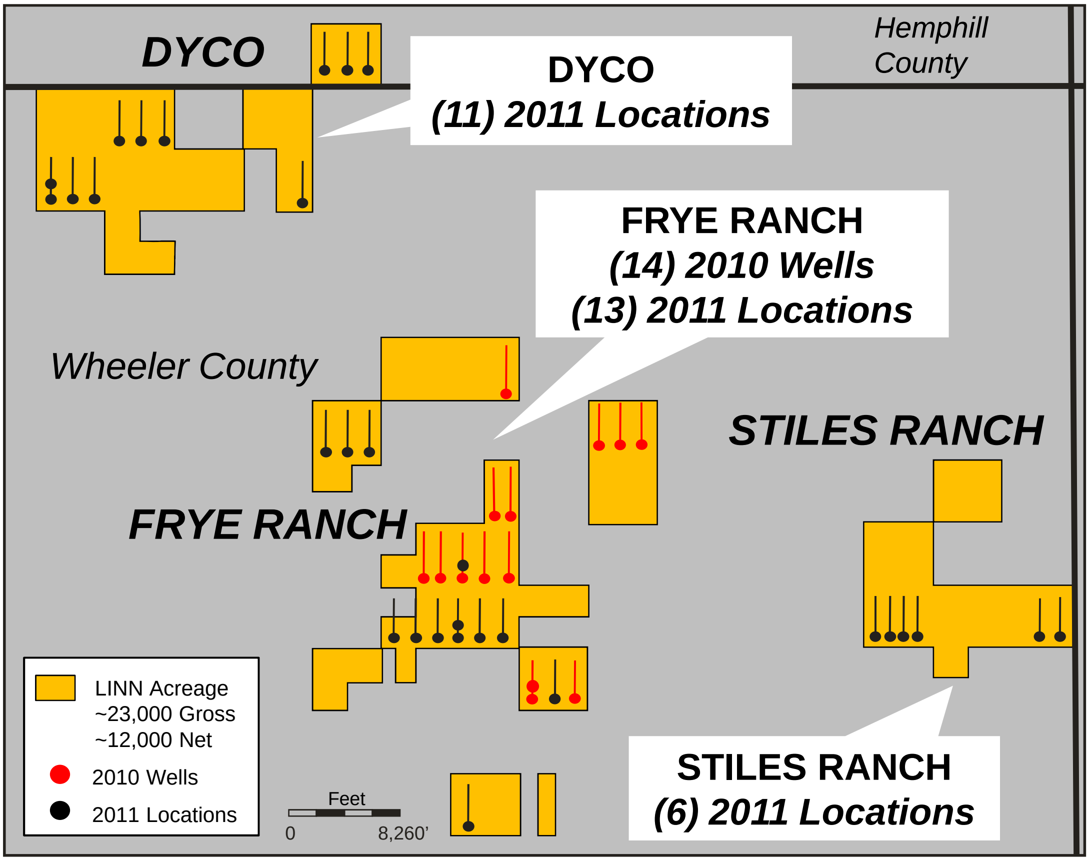
4th Quarter and Year-End 2010 Supplemental Financial and Operational Results

4th Quarter and Year-End 2010 Highlights

- **The Company reported the following significant fourth quarter and full year 2010 results:**
  - Increased average daily production 43 percent for the fourth quarter 2010 to 307 MMcfe/d, compared to 215 MMcfe/d for the fourth quarter 2009; and 22 percent to 265 MMcfe/d for the full year, compared to 218 MMcfe/d in 2009;
  - Increased adjusted EBITDA 55 percent to $221 million for the fourth quarter 2010, compared to $142 million for the fourth quarter 2009; and 29 percent to $732 million for the full year, compared to $566 million in 2009;
  - Increased distribution coverage ratio to 1.34x for the fourth quarter 2010, compared to fourth quarter 2009 of 1.04x; and 1.23x for the full year, compared to 1.14x in 2009; and
  - Delivered adjusted net income of $0.43 per unit for the fourth quarter and $1.54 per unit for the full year.
- **The Company also reported the following significant highlights:**
  - Increased distribution by 5 percent;
  - Delivered a total unitholder return of more than 45 percent;
  - Increased proved reserves 52 percent to 2.6 Tcfe, compared to 1.7 Tcfe in 2009;
  - Replaced 321 percent of production through organic activities in 2010 at a finding and development cost of $0.79 per Mcfe;
  - Closed approximately $1.4 billion in acquisitions – adding 671 Bcfe of proved reserves;
  - Strengthened balance sheet with undrawn $1.5 billion credit facility and $236 million available cash as of December 31, 2010;
  - Accessed the capital markets through two public equity offerings and two bond offerings that provided net proceeds of approximately $3 billion; and
  - Strengthened its commodity hedge portfolio, with current expected oil and natural gas production hedged approximately 100 percent on an equivalent basis through 2013, 80 percent in 2014 and 50 percent in 2015.

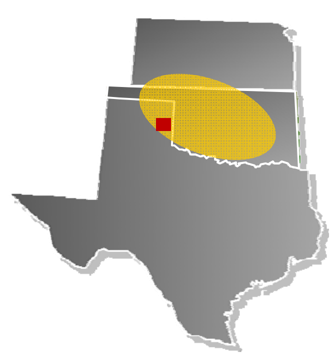
The financial summary follows; all amounts within are unaudited.

Granite Wash – Operated Horizontal Activity (Greater Stiles Ranch)

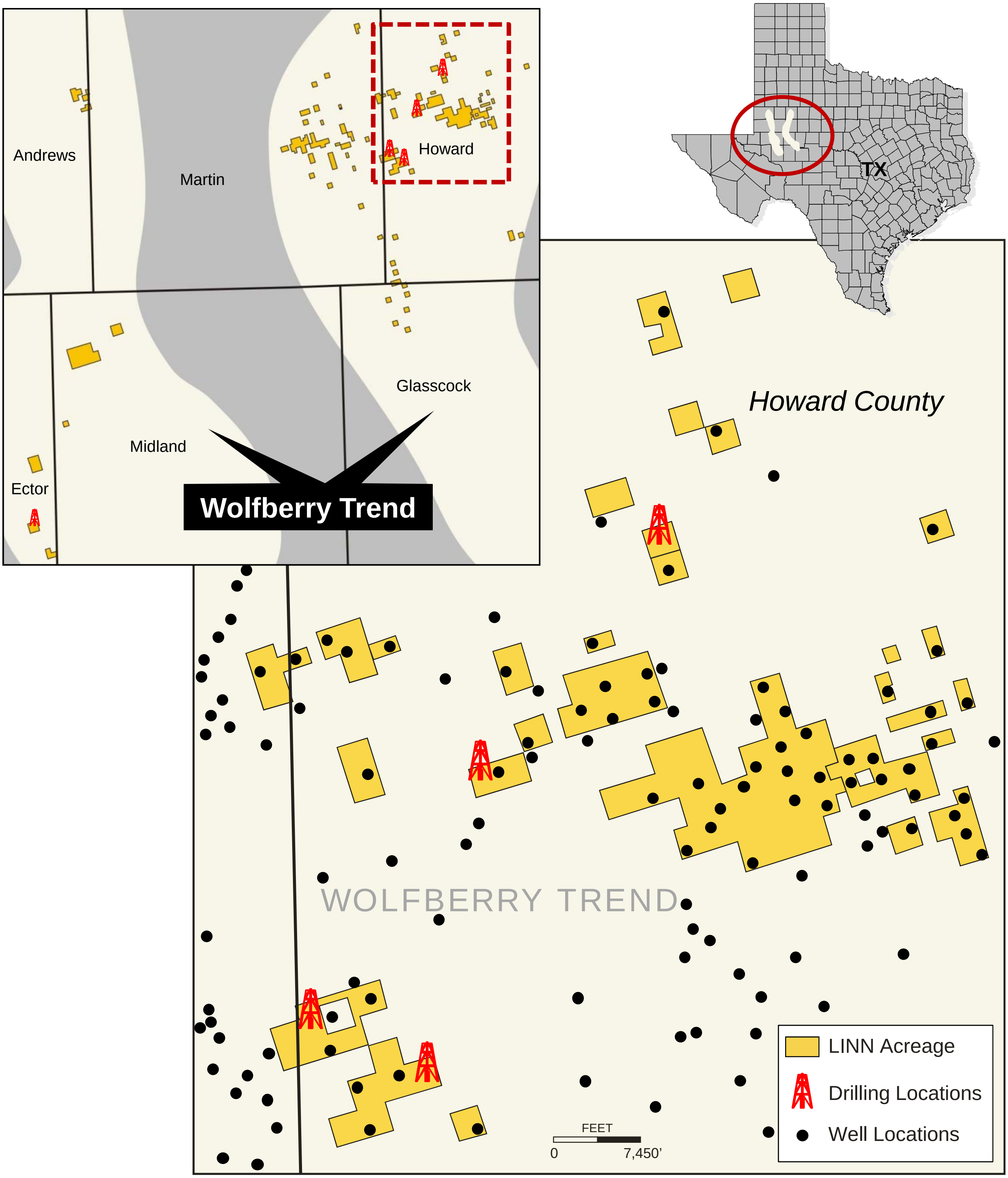


Greater Stiles Ranch	Status
2010	
Tom Puryear 5-28H	18.5 MMcfe/d – I.P.
McMahan 22-2H	19.4 MMcfe/d – I.P.
Black 50-1H	60.2 MMcfe/d – I.P.
Stein 1-3H	37.2 MMcfe/d – I.P.
Thomas 5-8H	26.2 MMcfe/d – I.P.
Stein 1-2H	20.5 MMcfe/d – I.P.
Black 49-1H	23.7 MMcfe/d – I.P.
Black 49-3H	24.6 MMcfe/d – I.P.
Black 50-2H	Initial Flowback
Black 49-2H	Completing
Puryear 28-7H	Completing
Puryear 28-6H	Waiting on completion
Thomas 5-9H	Waiting on completion
Thomas 5-10H	Waiting on completion

Greater Stiles Ranch	Status
2011	
Reed 31-4H	Waiting on completion
Reed 31-5H	Waiting on completion



Permian Basin – Operated Activity (Wolfberry Trend)



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Adjusted EBITDA

Adjusted EBITDA is a measure used by Company management to indicate (prior to the establishment of any reserves by its Board of Directors) the cash distributions the Company expects to make to its unitholders. Adjusted EBITDA is also a quantitative measure used throughout the investment community with respect to publicly-traded partnerships and limited liability companies.

The following presents a reconciliation of income (loss) from continuing operations to adjusted EBITDA:

	Three Months Ended December 31,		Year Ended December 31,	
	2010	**2009**	**2010**	**2009**
	(in thousands)			
Loss from continuing operations	$ (243,527)	$ (65,965)	$ (114,288)	$ (295,841)
Plus:				
Net operating cash flow from acquisitions and divestitures, effective date through closing date	20,129	115	42,846	3,708
Interest expense, cash	73,873	23,195	129,691	74,185
Interest expense, noncash	(7,482)	3,810	63,819	18,516
Depreciation, depletion and amortization	68,918	49,848	238,532	201,782
Impairment of goodwill and long-lived assets	38,600	—	38,600	—
Write-off of deferred financing fees and other	—	—	2,076	204
(Gains) losses on sale of assets and other, net	1,062	239	3,008	(23,051)
Provision for legal matters	(638)	—	4,362	—
Unrealized losses on commodity derivatives	267,102	128,652	232,376	591,379
Unrealized gains on interest rate derivatives	—	(10,261)	(63,978)	(16,588)
Realized losses on interest rate derivatives	—	11,252	8,021	42,881
Realized (gains) losses on canceled derivatives	—	—	123,865	(48,977)
Unit-based compensation expenses	3,246	3,616	13,792	15,089
Exploration costs	871	2,544	5,168	7,169
Income tax (benefit) expense	(1,469)	(4,600)	4,241	(4,221)
Adjusted EBITDA from continuing operations	$ 220,685	$ 142,445	$ 732,131	$ 566,235

The following presents a reconciliation of net cash provided by operating activities to adjusted EBITDA:

Net cash provided by operating activities for the three months ended December 31, 2010, was approximately $87 million and includes cash interest payments of approximately $73 million, premiums paid for commodity derivatives of approximately $29 million and other items totaling approximately $32 million that are not included in adjusted EBITDA. Net cash provided by operating activities for the three months ended December 31, 2009, was approximately $97 million and includes cash interest payments of approximately $23 million, cash settlements on interest rate derivatives of approximately $11 million and other items totaling approximately $11 million that are not included in adjusted EBITDA. Net cash provided by operating activities for the year ended December 31, 2010, was approximately $271 million and includes cash interest payments of approximately $129 million, premiums paid for commodity derivatives of approximately $120 million, cash settlements on interest rate derivatives of approximately $11 million, realized losses on canceled derivatives of approximately $124 million and other items totaling approximately $77 million that are not included in adjusted EBITDA. Net cash provided by operating activities for the year ended December 31, 2009, was approximately $427 million and includes cash interest payments of approximately $74 million, premiums paid for commodity derivatives of approximately $94 million, cash settlements on interest rate derivatives of approximately $42 million, realized gains on canceled derivatives of approximately $(49) million and other items totaling approximately $(22) million that are not included in adjusted EBITDA.

LINN Energy

Adjusted Net Income

Adjusted net income (a non-GAAP financial measure), as defined by the Company, may not be comparable to similarly titled measures used by other companies. Therefore, adjusted net income should be considered in conjunction with net income from continuing operations and other performance measures prepared in accordance with GAAP. Adjusted net income should not be considered in isolation or as a substitute for GAAP measures, such as net income or any other GAAP measure of liquidity or financial performance. Adjusted net income is a performance measure used by management to evaluate the Company's operational performance from oil and natural gas properties, prior to unrealized (gains) losses on derivatives, realized (gains) losses on canceled derivatives, impairment of goodwill and long-lived assets and (gains) losses on sale of assets, net.

The following presents a reconciliation of loss from continuing operations to adjusted net income:

	Three Months Ended December 31,		Year Ended December 31,	
	2010	2009	2010	2009
	(in thousands, except per unit amounts)			
Loss from continuing operations	$ (243,527)	$ (65,965)	$ (114,288)	$ (295,841)
Plus:				
Unrealized losses on commodity derivatives	267,102	128,652	232,376	591,379
Unrealized gains on interest rate derivatives	—	(10,261)	(63,978)	(16,588)
Realized (gains) losses on canceled derivatives	—	—	123,865	(48,977)
Impairment of goodwill and long-lived assets	38,600	—	38,600	—
(Gains) losses on sale of assets, net	1,015	239	2,914	(23,051)
Adjusted net income from continuing operations	$ 63,190	$ 52,665	$ 219,489	$ 206,922
Loss from continuing operations per unit – basic	$ (1.64)	$ (0.52)	$ (0.80)	$ (2.48)
Plus, per unit:				
Unrealized losses on commodity derivatives	1.80	1.01	1.63	4.95
Unrealized gains on interest rate derivatives	—	(0.08)	(0.45)	(0.14)
Realized (gains) losses on canceled derivatives	—	—	0.87	(0.41)
Impairment of goodwill and long-lived assets	0.26	—	0.27	—
(Gains) losses on sale of assets, net	0.01	—	0.02	(0.19)
Adjusted net income from continuing operations per unit – basic	$ 0.43	$ 0.41	$ 1.54	$ 1.73

Coverage Ratio Calculation

LINN ENERGY, LLC
COVERAGE RATIO CALCULATION

	Three Months Ended		Year Ended
	December 31, 2010	September 30, 2010	December 31, 2010
	(in thousands, except unit and ratio amounts)		
Adjusted EBITDA [1]	$ 220,685	$ 184,964	$ 732,131
Less: interest expense [2]	(61,388)	(49,982)	(186,410)
Less: maintenance capital expenditures	(27,105)	(25,015)	(88,245)
Distributable cash flow	$ 132,192	$ 109,967	$ 457,476
Distributable cash flow per unit	$ 0.88	$ 0.75	$ 3.18
Distribution per unit [3]	$ 0.66	$ 0.66	$ 2.58
Units outstanding (millions)	149.7	147.4	144.0
Distribution coverage ratio	1.34x	1.13x	1.23x

(1) Includes effects of the Company's hedge positions, cash flow adjustments from acquisition and divestiture activities, and other expenses.

(2) Includes cash payments for interest expense, and accrued interest on the Company's outstanding senior notes and the effects of the Company's interest rate swaps.

(3) Based on quarterly distribution of $0.63 per unit, or $2.52 per unit on an annualized basis, for Q1 and Q2 2010, and quarterly distribution of $0.66 per unit, or $2.64 per unit on an annualized basis, for Q3 and Q4 2010.

Statements of Operations

	Three Months Ended December 31, 2010	Three Months Ended December 31, 2009	Year Ended December 31, 2010	Year Ended December 31, 2009
	(in thousands, except per unit amounts)			
Revenues and other:				
Oil, natural gas and natural gas liquid sales	$ 210,167	$ 133,460	$ 690,054	$ 408,219
Gains (losses) on oil and natural gas derivatives	(188,088)	(55,849)	75,211	(141,374)
Natural gas marketing revenues	714	1,330	3,966	4,380
Other revenues	1,686	167	3,049	1,924
	24,479	79,108	772,280	273,149
Expenses:				
Lease operating expenses	46,892	32,325	158,382	132,647
Transportation expenses	4,564	6,352	19,594	18,202
Natural gas marketing expenses	507	836	2,716	2,154
General and administrative expenses	27,533	22,887	99,078	86,134
Exploration costs	871	2,544	5,168	7,169
Bad debt expenses	43	(99)	(46)	401
Depreciation, depletion and amortization	68,918	49,848	238,532	201,782
Impairment of goodwill and long-lived assets	38,600	—	38,600	—
Taxes, other than income taxes	12,580	6,191	45,182	27,605
(Gains) losses on sale of assets and other, net	837	119	6,536	(24,598)
	201,345	121,003	613,742	451,496
Other income and (expenses):				
Interest expense, net of amounts capitalized	(66,391)	(27,005)	(193,510)	(92,701)
Losses on interest rate swaps	—	(991)	(67,908)	(26,353)
Other, net	(1,739)	(674)	(7,167)	(2,661)
	(68,130)	(28,670)	(268,585)	(121,715)
Loss from continuing operations before income taxes	(244,996)	(70,565)	(110,047)	(300,062)
Income tax benefit (expense)	1,469	4,600	(4,241)	4,221
Loss from continuing operations	(243,527)	(65,965)	(114,288)	(295,841)
Discontinued operations:				
Gains (losses) on sale of assets, net of taxes	—	560	—	(158)
Loss from discontinued operations, net of taxes	—	(7)	—	(2,193)
	—	553	—	(2,351)
Net loss	$ (243,527)	$ (65,412)	$ (114,288)	$ (298,192)
Loss per unit – continuing operations:				
Basic	$ (1.64)	$ (0.52)	$ (0.80)	$ (2.48)
Diluted	$ (1.64)	$ (0.52)	$ (0.80)	$ (2.48)
Income (loss) per unit – discontinued operations:				
Basic	$ —	$ 0.01	$ —	$ (0.02)
Diluted	$ —	$ 0.01	$ —	$ (0.02)
Loss per unit:				
Basic	$ (1.64)	$ (0.51)	$ (0.80)	$ (2.50)
Diluted	$ (1.64)	$ (0.51)	$ (0.80)	$ (2.50)
Weighted average units outstanding:				
Basic	148,284	127,308	142,535	119,307
Diluted	148,284	127,308	142,535	119,307
Distributions declared per unit	$ 0.66	$ 0.63	$ 2.55	$ 2.52

Operating Statistics – Continuing Operations

	Three Months Ended December 31, 2010	Three Months Ended December 31, 2009	Year Ended December 31, 2010	Year Ended December 31, 2009
Average daily production:				
Natural gas (MMcf/d)	154	112	137	125
Oil (MBbls/d)	16.4	9.6	13.1	9.0
NGL (MBbls/d)	9.1	7.6	8.3	6.5
Total (MMcfe/d)	307	215	265	218
Weighted average prices (hedged): [1]				
Natural gas (Mcf)	$ 8.17	$ 8.97	$ 8.52	$ 8.27
Oil (Bbl)	$ 91.90	$ 103.62	$ 94.71	$ 110.94
NGL (Bbl)	$ 41.17	$ 31.71	$ 39.14	$ 28.04
Weighted average prices (unhedged): [2]				
Natural gas (Mcf)	$ 3.78	$ 4.75	$ 4.24	$ 3.51
Oil (Bbl)	$ 80.75	$ 70.40	$ 75.16	$ 55.25
NGL (Bbl)	$ 41.17	$ 31.71	$ 39.14	$ 28.04
Average NYMEX prices:				
Natural gas (MMBtu)	$ 3.84	$ 4.16	$ 4.40	$ 3.99
Oil (Bbl)	$ 85.17	$ 76.19	$ 79.53	$ 61.94
Costs per Mcfe of production:				
Lease operating expenses	$ 1.66	$ 1.63	$ 1.64	$ 1.67
Transportation expenses	$ 0.16	$ 0.32	$ 0.20	$ 0.23
General and administrative expenses [3]	$ 0.97	$ 1.16	$ 1.02	$ 1.08
Depreciation, depletion and amortization	$ 2.44	$ 2.52	$ 2.46	$ 2.53
Taxes, other than income taxes	$ 0.45	$ 0.31	$ 0.47	$ 0.35

(1) Includes the effect of realized gains on derivatives of $79 million and $73 million for the three months ended December 31, 2010, and December 31, 2009, respectively. Includes the effect of realized gains on derivatives of $308 million and $401 million (excluding $49 million realized net gains on canceled contracts) for the years ended December 31, 2010, and December 31, 2009, respectively.

(2) Does not include the effect of realized gains (losses) on derivatives.

(3) General and administrative expenses for the three months ended December 31, 2010, and December 31, 2009, include approximately $3 million and $4 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the three months ended December 31, 2010, and December 31, 2009, were $0.86 per Mcfe and $0.98 per Mcfe, respectively. General and administrative expenses for the years ended December 31, 2010, and December 31, 2009, includes approximately $13 million and $15 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the years ended December 31, 2010, and December 31, 2009, were $0.88 per Mcfe and $0.90 per Mcfe, respectively.

LINN Energy

Selected Balance Sheet Data

	December 31, 2010	December 31, 2009
	(in thousands)	
Assets:		
Total current assets	$ 710,909	$ 409,460
Oil and natural gas properties, net	4,945,468	3,613,382
Other property and equipment, net	104,752	95,284
Other noncurrent assets, net	172,019	222,130
Total assets	$ 5,933,148	$ 4,340,256
Liabilities and unitholders' capital:		
Total current liabilities	$ 315,108	$ 209,305
Credit facility	—	1,100,000
Senior notes, net	2,742,902	488,831
Other noncurrent liabilities	86,922	90,116
Total liabilities	3,144,932	1,888,252
Unitholders' capital	2,788,216	2,452,004
Total liabilities and unitholders' capital	$ 5,933,148	$ 4,340,256

Selected Cash Flow Data

	Year Ended December 31, 2010	Year Ended December 31, 2009
	(in thousands)	
Net cash provided by operating activities [1]	$ 270,918	$ 426,804
Net cash used in investing activities	(1,581,408)	(282,273)
Net cash provided by (used in) financing activities	1,524,260	(150,968)
Net increase (decrease) in cash and cash equivalents	213,770	(6,437)
Cash and cash equivalents:		
Beginning	22,231	28,668
Ending	$ 236,001	$ 22,231

[1] The years ended December 31, 2010, and December 31, 2009, include premiums paid for derivatives of approximately $120 million and $94 million, respectively.

Guidance Table

	Q1 2011E		FY 2011E	
Net Production and Other Revenues				
Natural Gas (MMcf/d)	154 -	160	163 -	178
Oil (Bbls/d)	16,893 -	17,447	18,455 -	20,133
NGL (Bbls/d)	8,191 -	8,459	9,349 -	10,199
Total (MMcfe/d)	305 -	315	330 -	360
Other revenues, net (in thousands) (1)	$1,100 -	$1,300	$5,500 -	$6,500
Costs (in thousands)				
LOE	$45,500 -	$49,500	$195,000 -	$205,000
Transportation	5,000 -	7,000	27,000 -	31,000
Production and ad valorem taxes	14,000 -	16,000	66,000 -	72,000
Total operating expenses	$64,500 -	$72,500	$288,000 -	$308,000
General and administrative expenses - non-GAAP (2)	$24,000 -	$26,000	$93,000 -	$97,000
Depreciation, depletion and amortization	$65,000 -	$71,000	$300,000 -	$320,000
Costs per Mcfe (Mid-Point)				
LOE	$1.70		$1.59	
Transportation	0.22		0.23	
Production and ad valorem taxes	0.54		0.55	
Total operating expenses	$2.46		$2.37	
General and administrative expenses - non-GAAP (2)	$0.90		$0.75	
Depreciation, depletion and amortization	$2.44		$2.46	
Targets (Mid-Point) (in thousands)				
Adjusted EBITDA (3)	$192,000		$880,000	
Interest expense (4)	(60,000)		(235,000)	
Maintenance capital expenditures	(26,400)		(120,000)	
Distributable cash flow	$105,600		$525,000	
Distributable cash flow per unit (5)	$0.66		$3.28	
Distribution per unit (5) (6)	$0.66		$2.64	
Distribution coverage ratio (5) (6)	1.00x		1.24x	
Adjusted net income per unit (5) (7) (8)	$0.33		$1.82	
Weighted Average NYMEX Differentials				
Natural Gas (MMBtu)	$(0.20) -	---	$(0.20) -	---
Oil (Bbl)	$(5.15) -	$(3.15)	$(5.00) -	$(3.00)
NGL realization on crude oil price (%)	45% -	49%	44% -	48%

Unhedged Commodity Price Assumptions	January	February	March	Remainder
Natural Gas (MMBtu)	$4.22	$4.32	$3.92	$4.23
Oil (Bbl)	$89.58	$87.95	$85.58	$95.99

Continued

Guidance Table – *Continued*

(1) Includes other revenues and margin on natural gas marketing activities.

(2) Excludes unit-based compensation, which represents a noncash charge based on equity-related compensation.

(3) Includes effects of the Company's hedge positions, cash flow adjustments from acquisition and divestiture activities and other expenses.

(4) Includes cash payments for interest, accrued interest on the Company's senior notes and the effects of interest rate swaps. Excludes the noncash amortization of deferred financing fees of approximately $4 million in Q1 2011 ($18 million for full year 2011). Amortization of deferred financing fees is included in interest expense on the statements of operations.

(5) Assumes 159.8 million and 160.0 million units outstanding for Q1 2011 and full year 2011, respectively.

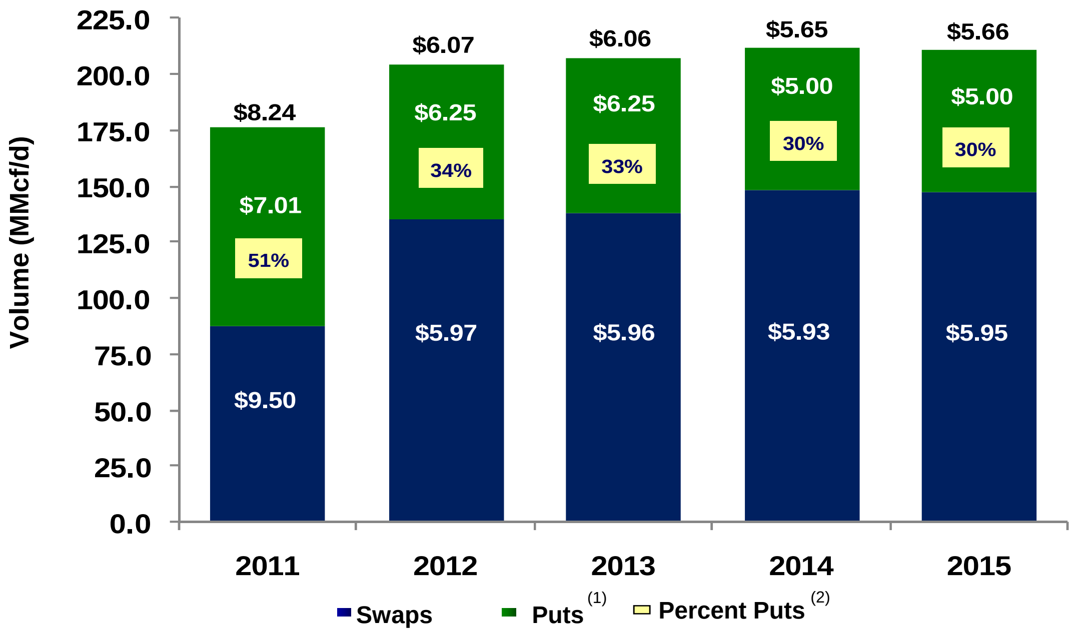
(6) Based on current quarterly distribution of $0.66 per unit, or $2.64 per unit annualized.

(7) Excludes unrealized (gains) losses on commodity and interest rate derivatives, realized (gains) losses on canceled derivatives and (gains) losses on sale of assets and includes unit-based compensation and exploration costs.

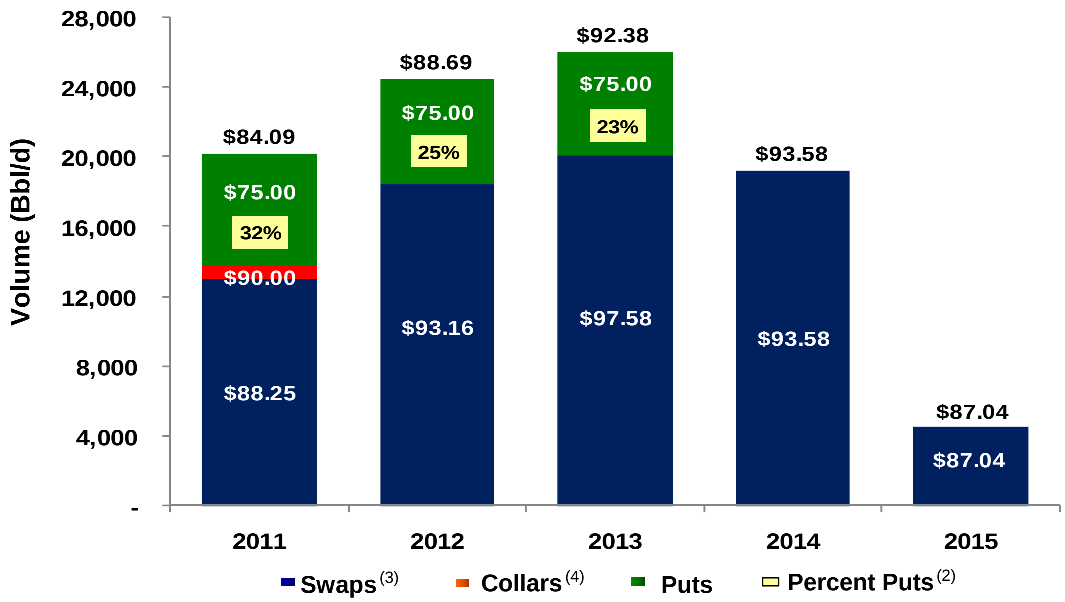
(8) Includes the noncash amortization of deferred financing fees of approximately $4 million in Q1 2011 ($18 million for full year 2011).

Commodity Hedge Positions

Natural Gas Positions



Oil Positions



Note: Includes full-year 2011-2015 hedging positions.
(1) Natural gas positions include puts which settle on the Panhandle Eastern Pipeline Index (PEPL) to hedge basis differential associated with natural gas production in the Mid-Continent.
(2) Calculated as percentage of hedged volumes in the form of puts.
(3) The Company has certain outstanding fixed price oil swaps on 14,750 Bbls per day which may be extended annually at a price of $100.00 per Bbl for each of 2015, 2016 and 2017 if the counterparties determine that the strike prices are in-the-money on a designated date in each respective preceding year. The extension for each year is exercisable without respect to the other years.
(4) Includes collars with floor / ceiling prices of $90.00 / $112.25 on 276 MBbls of oil for FY 2011.

Guidance Table – Commodity Hedge Summary

Natural Gas Positions	**Q1 2011E**	**FY 2011E**
Fixed Price Swaps:		
Hedged Volume (MMMBtu)	7,975	31,901
Average Price ($/MMBtu)	$9.50	$9.50
Puts:		
Hedged Volume (MMMBtu)	4,782	19,297
Average Price ($/MMBtu)	$6.00	$5.98
PEPL Puts: (1)		
Hedged Volume (MMMBtu)	3,315	13,259
Average Price ($/MMBtu)	$8.50	$8.50
Total:		
Hedged Volume (MMMBtu)	16,072	64,457
Average Price ($/MMBtu)	$8.25	$8.24
Oil Positions		
Fixed Price Swaps:		
Hedged Volume (MBbls)	1,175	4,737
Average Price ($/Bbl)	$88.27	$88.25
Puts:		
Hedged Volume (MBbls)	588	2,352
Average Price ($/Bbl)	$75.00	$75.00
Collars:		
Hedged Volume (MBbls)	69	276
Average Floor Price ($/Bbl)	$90.00	$90.00
Average Ceiling Price ($/Bbl)	$112.25	$112.25
Total:		
Hedged Volume (MBbls)	1,832	7,365
Average Price ($/Bbl)	$84.07	$84.09
Natural Gas Basis Differential Positions		
PEPL Basis Swaps: (1)		
Hedged Volume (MMMBtu)	8,885	35,541
Average Price ($/MMBtu)	$(0.96)	$(0.96)

Includes positions covering production for all months within periods specified.

(1) Settle on the PEPL spot price of natural gas to hedge basis differential associated with natural gas production in the Mid-Continent region.

Commodity Hedge Portfolio

The following table summarizes open positions as of December 31, 2010, and represents, as of such date, derivatives in place through December 31, 2015, on annual production volumes:

Natural Gas Positions	**2011**	**2012**	**2013**	**2014**	**2015**
Fixed Price Swaps:					
Hedged Volume (MMMBtu)	31,901	49,410	50,278	54,202	53,837
Average Price ($/MMBtu)	$9.50	$5.97	$5.96	$5.93	$5.95
Puts:					
Hedged Volume (MMMBtu)	19,297	25,364	25,295	23,178	23,178
Average Price ($/MMBtu)	$5.98	$6.25	$6.25	$5.00	$5.00
PEPL Puts: [1]					
Hedged Volume (MMMBtu)	13,259	---	---	---	---
Average Price ($/MMBtu)	$8.50	$ ---	$ ---	$ ---	$ ---
Total:					
Hedged Volume (MMMBtu)	64,457	74,774	75,573	77,380	77,015
Average Price ($/MMBtu)	$8.24	$6.07	$6.06	$5.65	$5.66
Oil Positions					
Fixed Price Swaps: [2]					
Hedged Volume (MBbls)	4,737	6,734	7,318	7,026	1,643
Average Price ($/Bbl)	$88.25	$93.16	$97.58	$93.58	$87.04
Puts:					
Hedged Volume (MBbls)	2,352	2,196	2,190	---	---
Average Price ($/Bbl)	$75.00	$75.00	$75.00	$ ---	$ ---
Collars:					
Hedged Volume (MBbls)	276	---	---	---	---
Average Floor Price ($/Bbl)	$90.00	$ ---	$ ---	$ ---	$ ---
Average Ceiling Price ($/Bbl)	$112.25	$ ---	$ ---	$ ---	$ ---
Total:					
Hedged Volume (MBbls)	7,365	8,930	9,508	7,026	1,643
Average Price ($/Bbl)	$84.09	$88.69	$92.38	$93.58	$87.04
Natural Gas Basis Differential Positions					
PEPL Basis Swaps: [1]					
Hedged Volume (MMMBtu)	35,541	37,735	38,854	42,194	42,194
Hedged Differential ($/MMBtu)	$(0.96)	$(0.89)	$(0.89)	$(0.39)	$(0.39)

(1) Settle on the Panhandle Eastern Pipeline ("PEPL") spot price of natural gas to hedge basis differential associated with natural gas production in the Mid-Continent region.

(2) As presented in the table above, the Company has certain outstanding fixed price oil swaps on 14,750 Bbls of daily production which may be extended annually at a price of $100.00 per Bbl for each of 2015, 2016 and 2017 if the counterparties determine that the strike prices are in-the-money on a designated date in each respective preceding year. The extension for each year is exercisable without respect to the other years.

Combined Revenues

Combined revenues (a non-GAAP financial measure), as defined by the Company, may not be comparable to similarly titled measures used by other companies. Therefore, combined revenues should be considered in conjunction with total revenues and other performance measures prepared in accordance with GAAP. Combined revenues should not be considered in isolation or as a substitute for GAAP measures of liquidity or financial performance. Company management believes that the presentation of combined revenues provides useful information to investors because it is commonly used by investors and securities analysts in evaluating oil and natural gas companies.

The following presents a reconciliation of revenues and other to combined revenues:

	Three Months Ended December 31,		Year Ended December 31,	
	2010	2009	2010	2009
	(in thousands)			
Revenues and other	$ 24,479	$ 79,108	$ 772,280	$ 273,149
Less:				
Unrealized losses on commodity derivatives	267,102	128,652	232,376	591,379
Natural gas marketing revenues	(714)	(1,330)	(3,966)	(4,380)
Other revenues	(1,686)	(167)	(3,049)	(1,924)
Combined Revenues	$ 289,181	$ 206,263	$ 997,641	$ 858,224
(Gains) losses on commodity derivatives	$ (188,088)	$ (55,849)	$ 75,211	$ (141,374)
Less:				
Unrealized losses on commodity derivatives	267,102	128,652	232,376	591,379
Realized gains on canceled commodity derivatives	-	-	-	(49,037)
Hedge revenues	$ 79,014	$ 72,803	$ 307,587	$ 400,968

Reserve Replacement Metrics

The reserve replacement metrics provided herein are non-GAAP financial measures. The methods used by the Company to calculate reserve replacement cost and finding and development cost may differ from methods used by other companies to compute similar measures. As a result, the Company's measures may not be comparable to similar measures provided by other companies. The Company believes that providing such measures is useful in evaluating the cost to add proved reserves; however, these measures should not be considered in isolation or as a substitute for GAAP measures, such as costs incurred in oil and natural gas property acquisition and development, contained in the Company's financial statements prepared in accordance with GAAP. The following presents the calculations of reserve replacement cost and finding and development cost from continuing operations:

	Year Ended December 31,	
	2010	2009
Costs incurred (in thousands):		
Costs incurred in oil and natural gas property acquisition, exploration and development	$ 1,602,086	$ 258,105
Less:		
Asset retirement obligation costs	(748)	(371)
Property acquisition costs	(1,356,430)	(115,929)
Oil and natural gas capital costs expended, excluding acquisitions	$ 244,908	$ 141,805
Reserve data (MMcfe):		
Purchase of minerals in place	671,146	61,684
Extensions, discoveries and other additions	234,324	50,416
Add:		
Revisions of previous estimates	76,281	19,280
Annual additions	981,751	131,380
Less:		
Purchase of minerals in place	(671,146)	(61,684)
Annual additions, excluding acquisitions	310,605	69,696
Annual production (MMcfe)	96,827	79,580
Reserve replacement metrics:		
Reserve replacement cost per Mcfe (1)	$ 1.63	$ 1.96
Reserve replacement ratio (2)	1,014%	165%
Finding and development cost from the drillbit per Mcfe (3)	$ 0.79	$ 2.03
Drillbit reserve replacement ratio (4)	321%	88%

(1) (Oil and natural gas capital costs expended) divided by (Annual additions)

(2) (Annual additions) divided by (Annual production)

(3) (Oil and natural gas capital costs expended, excluding acquisitions) divided by (Annual additions, excluding acquisitions)

(4) (Annual additions, excluding acquisitions) divided by (Annual production)

PV-10

PV-10 represents the present value, discounted at 10% per year, of estimated future net revenues. The Company's calculation of PV-10 differs from the standardized measure of discounted future net cash flows determined in accordance with the rules and regulations of the Securities and Exchange Commission in that it is presented including the impacts of its oil and natural gas hedge values for 2011-2015 and strip prices as of December 31, 2010, rather than the average price during the 12-month period, determined as an unweighted average of the first-day-of-the-month price for each month, and without giving effect to derivatives. The Company calculates PV-10 value in this manner because such a large percentage of the Company's forecasted oil and natural gas production is hedged for multiple-year periods, and management therefore believes that its PV-10 calculation more accurately reflects the value of its estimated future net revenues. The information used to calculate PV-10 is not derived directly from data determined in accordance with the provisions of applicable accounting standards. The Company's calculation of PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows determined in accordance with the rules and regulations of the Securities and Exchange Commission. The following presents a reconciliation of standardized measure of discounted future net cash flows to the Company's calculation of PV-10 at December 31, 2010 (in millions):

Standardized measure of discounted future net cash flows	$	4,224
Plus: Difference due to oil and natural gas hedge prices and strip prices for unhedged volumes		1,577
PV-10	$	5,801