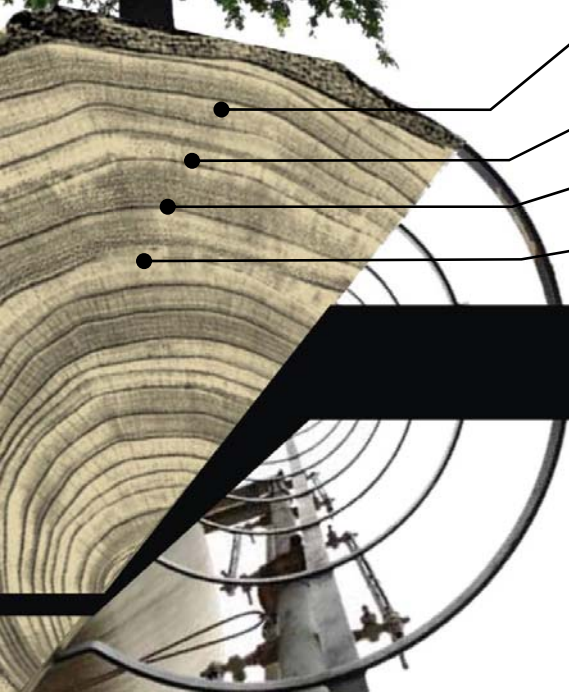


Supplemental Q1 2011 Financial and Operational Results



NASDAQ:LINE



DISTRIBUTION GROWTH

ACQUISITIONS

ASSETS

PEOPLE



The power of **STABILITY** *and*
GROWTH

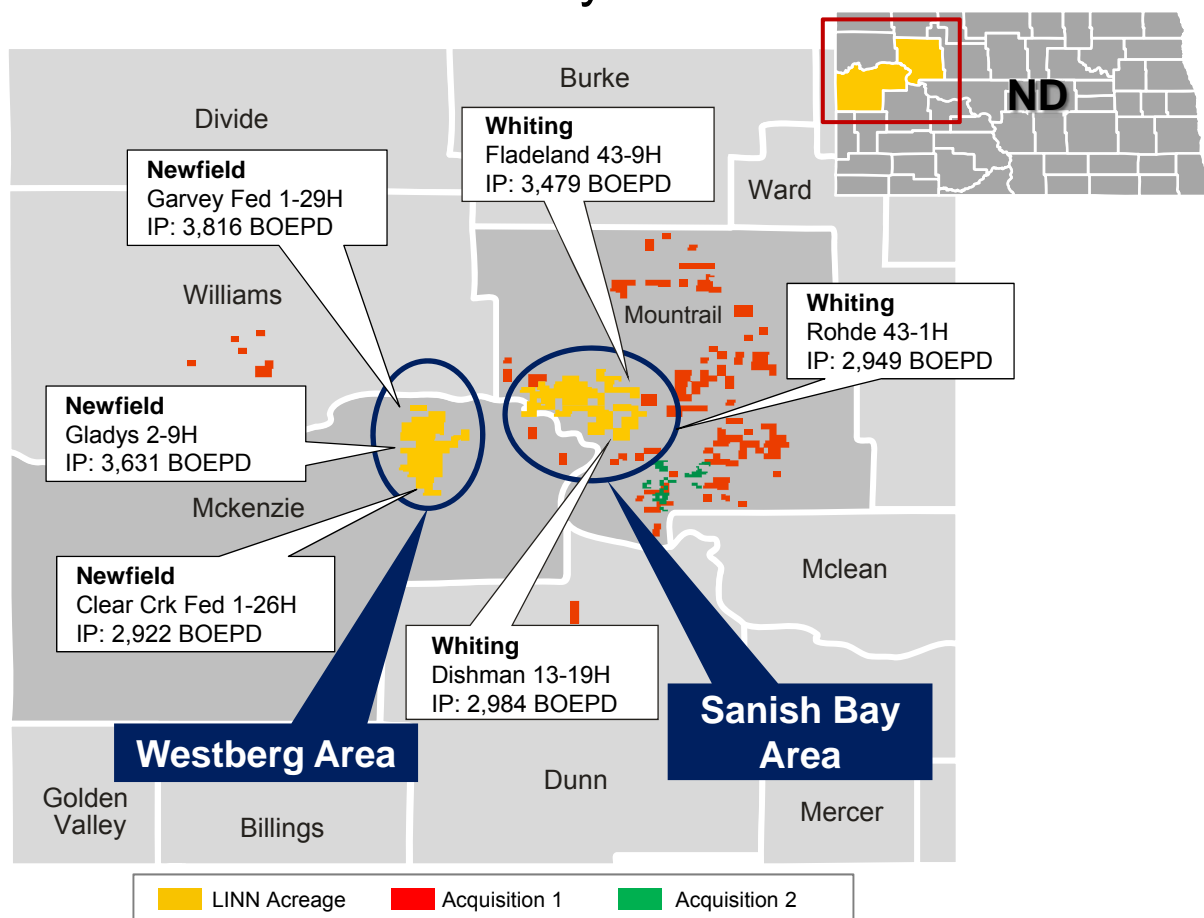
1st Quarter 2011 Highlights

- The Company reports the following significant first quarter results, which exceeded mid-point guidance in all categories:
 - Average daily production of 312 MMcfe/d;
 - Lease operating expenses of \$1.63 per Mcfe;
 - Adjusted EBITDA of \$210 million;
 - Distribution coverage ratio of 1.15x; and
 - Adjusted net income per unit of \$0.38.

- The Company also reports the following significant highlights:
 - Executed a total of \$637 million in acquisition agreements, including;
 - Entering a new operating region through completion of an acquisition of properties in the Williston Basin Bakken play for a contract price of \$196 million;
 - Signing purchase agreements for two additional Williston Basin bolt-on acquisitions for a combined contract price of \$163 million;
 - Completing two bolt-on acquisitions in the Permian Basin for a combined contract price of \$238 million;
 - Completed a \$649 million public equity offering;
 - Retired a combined 81 percent of principal 11.75 percent senior notes due 2017 and 9.875 percent senior notes due 2018 through redemptions and tender offers; and
 - Revised 2011 guidance implies average coverage of 1.40x for the remainder of the year.

The financial summary follows; all amounts within are unaudited.

Williston Basin – Bakken Play



Overview

➤ Strategic entry into premier oil basin

- Non-operated position with high quality operators
- Offers high rates of return
- Significant growth potential
- Bolt-on opportunities

➤ Current position

- ~14 MMBoe
- ~2,500 Boe/d of current production
- 17,000 net acres
- 87% liquids
- 32% proved developed
- >15 year reserve life

➤ Growth opportunities

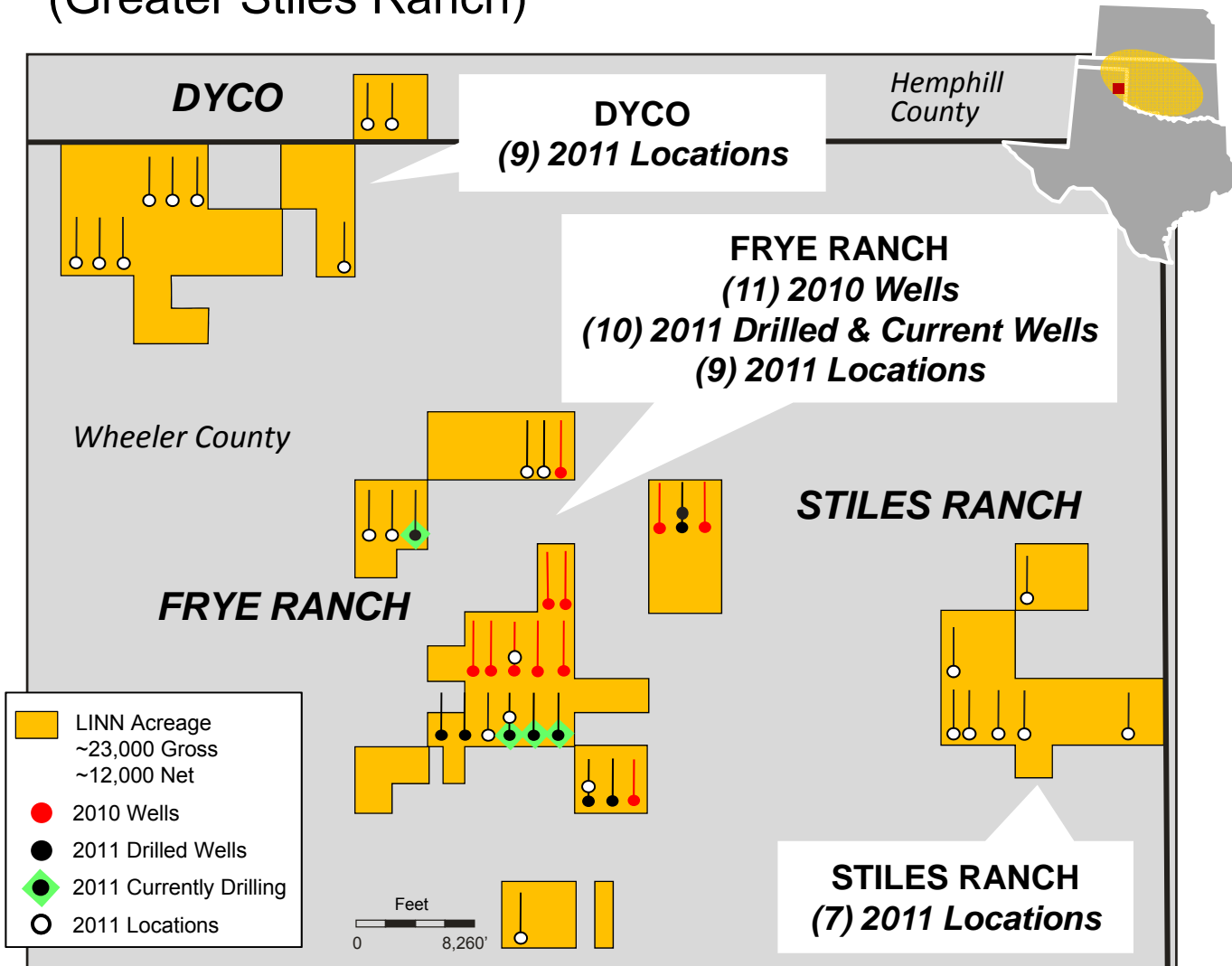
- ~800 future drilling locations

Acquisitions Overview

- \$163 million (2 separate transactions)
- ~6 MMBoe total proved reserves
- ~1,150 Boe/d of current production
- 13 year reserve life
- 39% proved developed
- ~6,200 net acres
- ~400 future drilling locations

Note: All operational and reserve data as of December 31, 2010, pro forma for pending and closed 2011 acquisitions. Estimates of proved reserves for pending and closed 2011 acquisitions were calculated as of the effective dates of the acquisitions using forward strip oil and natural gas prices, which differ from estimates calculated in accordance with SEC rules and regulations.

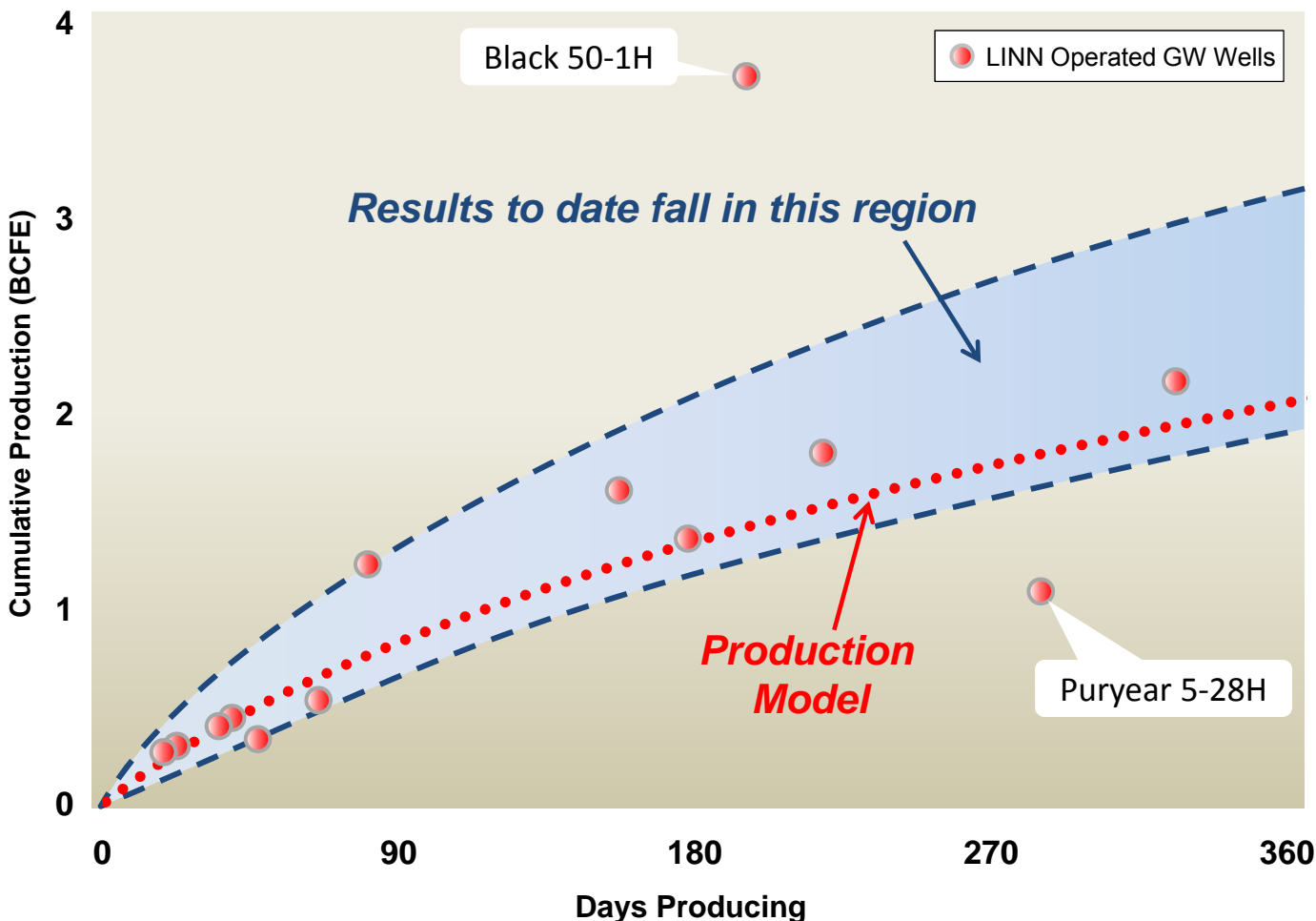
Texas Granite Wash – Operated Horizontal Activity (Greater Stiles Ranch)



Well Status	Operated	Non-Operated
Producing	13	9
Drilling	4	4
Waiting on Completion	4	5
Completing	<u>3</u>	<u>0</u>
Total	24	18

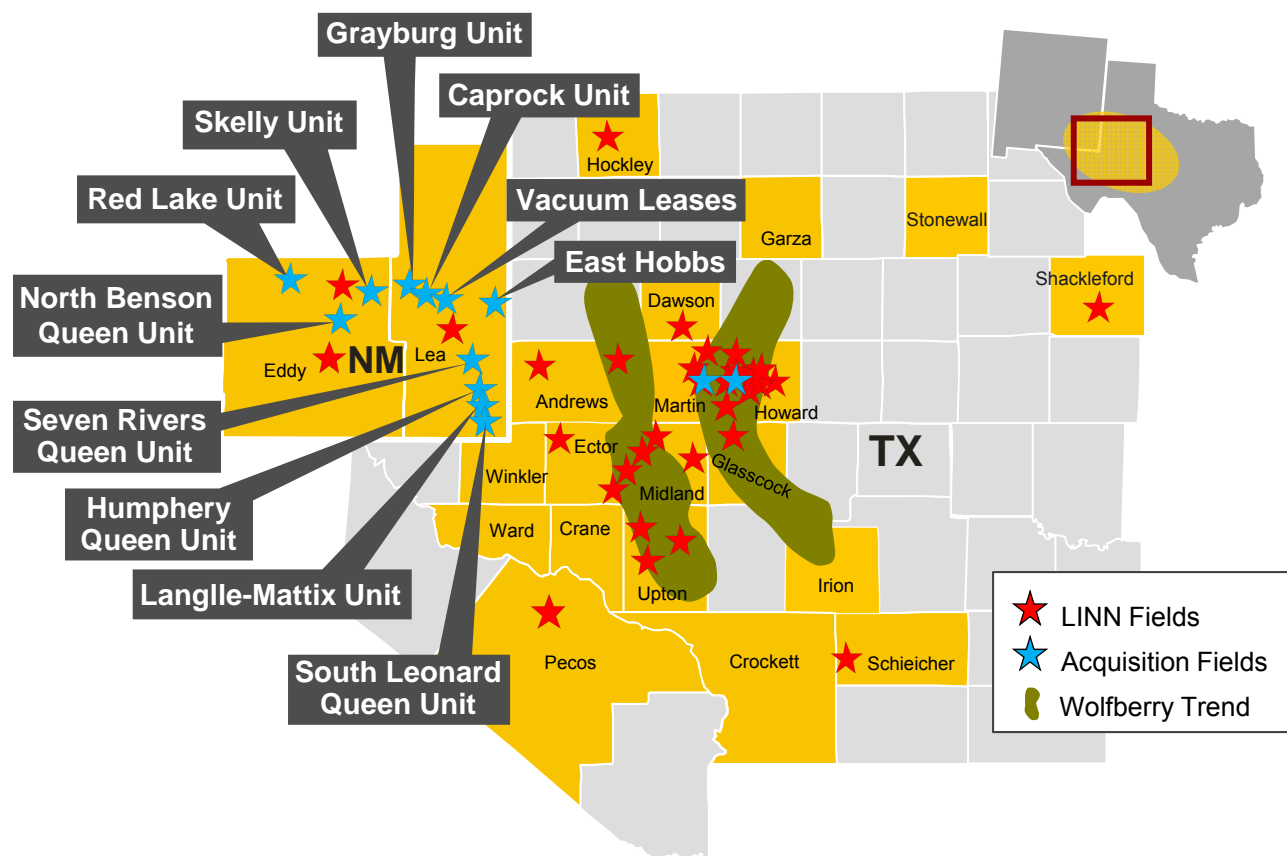
Note: Well status as of April 18, 2011.

Texas Granite Wash Horizontal Program Cumulative Production by Well



- Graph represents cumulative production performance of LINN-operated Granite Wash wells over time compared to production model
- Relatively narrow band of results indicates repeatability of program
- On average, well results have exceeded production model
- Puryear 5-28 H well was drilled by another operator and production has been limited due to mechanical issues

Permian Basin – Overview



Overview

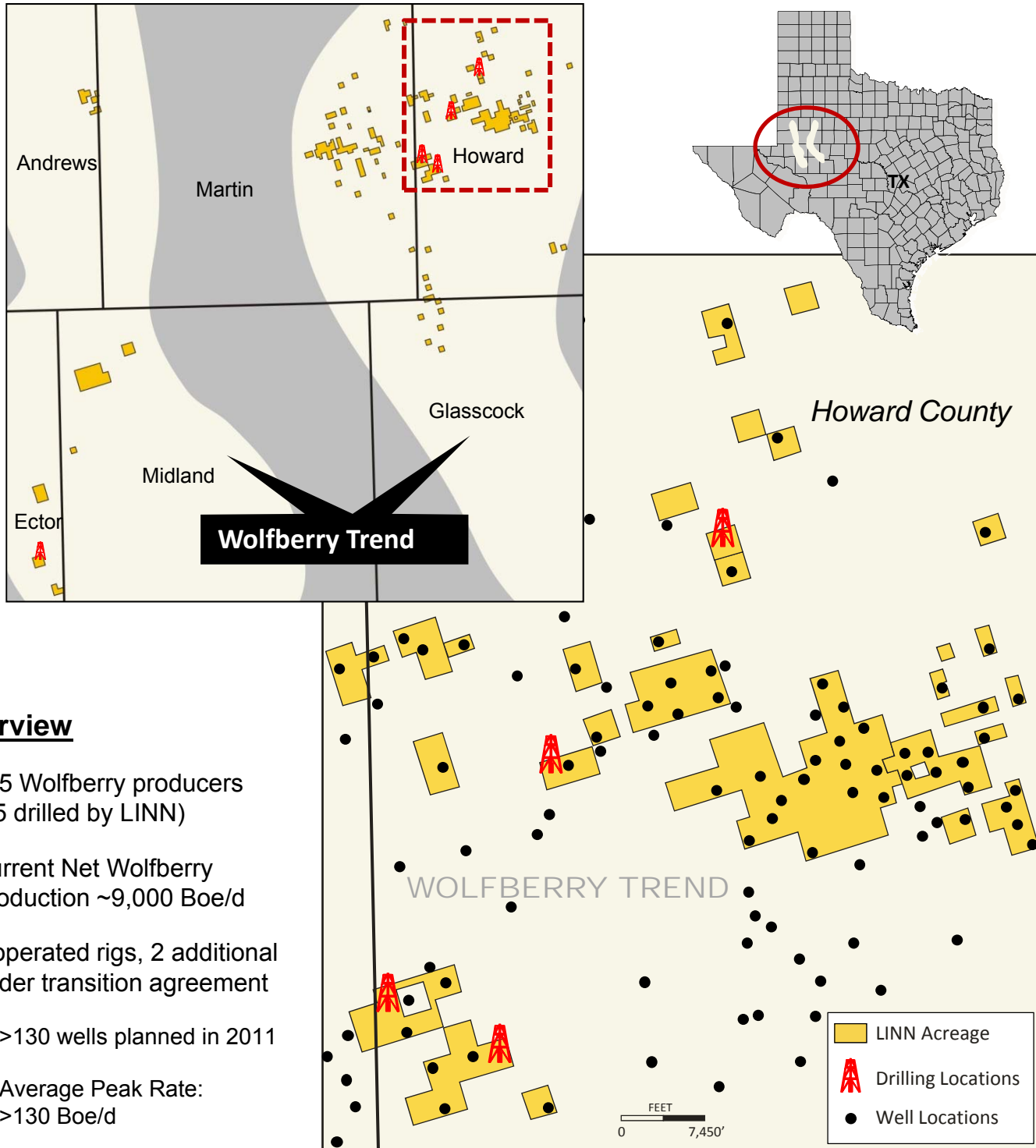
- **Long-life, low risk reserves**
 - 88 MMBoe proved reserves
 - 78% liquids (~45% proved developed)
 - Production of ~12,000 Boe/d
 - Reserve life of over 20 years
 - 19% of total reserves
- **Acreage position**
 - ~102,000 net acres
 - ~88,000 net developed acres
- **Growth opportunities**
 - ~700 proved low-risk infill drilling and optimization opportunities
 - Opportunities for bolt-on acquisitions

Acquisitions Overview

- \$238 million (2 separate transactions)
- ~14 MMBoe total proved reserves
- 48% proved developed
- ~1,700 Boe/d
- >20 year reserve-life index
- ~24,000 net acres
- ~180 future drilling locations

Note: All operational and reserve data as of December 31, 2010, pro forma for completed 2011 acquisitions. Estimates of proved reserves for completed 2011 acquisitions were calculated as of the effective dates of the acquisitions using forward strip oil and natural gas prices, which differ from estimates calculated in accordance with SEC rules and regulations.

Permian Basin – Operated Activity (Wolfberry Trend)



Overview

- 225 Wolfberry producers (45 drilled by LINN)
- Current Net Wolfberry Production ~9,000 Boe/d
- 5 operated rigs, 2 additional under transition agreement
 - >130 wells planned in 2011
 - Average Peak Rate: >130 Boe/d
 - Highest peak rate >700 Boe/d
 - EUR's of 100 – 160 MBoe

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 net income (loss) to adjusted EBITDA:

	Three Months Ended	
	March 31,	
	2011	2010
	(in thousands)	
Net income (loss)	\$ (446,682)	\$ 65,310
Plus:		
Net operating cash flow from acquisitions and divestitures, effective date through closing date	7,051	5,391
Interest expense, cash	63,590	21,752
Interest expense, noncash	(126)	5,901
Depreciation, depletion and amortization	66,366	49,191
(Gains) losses on sale of assets and other, net	(823)	414
Provision for legal matters	492	—
Loss on extinguishment of debt	84,562	—
Unrealized (gains) losses on commodity derivatives	425,285	(33,500)
Unrealized losses on interest rate derivatives	—	15,141
Realized losses on interest rate derivatives	—	8,021
Unit-based compensation expenses	5,638	4,135
Exploration costs	445	3,861
Income tax expense	4,198	5,892
Adjusted EBITDA	<u>\$ 209,996</u>	<u>\$ 151,509</u>

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 March 31, 2011, was approximately \$108 million and includes cash interest payments of approximately \$63 million and other items totaling approximately \$39 million that are not included in adjusted EBITDA. Net cash provided by operating activities for the three months ended March 31, 2010, was approximately \$80 million and includes cash interest payments of approximately \$22 million, cash settlements on interest rate derivatives of approximately \$11 million, premiums paid for commodity derivatives of approximately \$15 million and other items totaling approximately \$24 million that are not included in adjusted EBITDA.

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 (loss) 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 (loss) 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, loss on extinguishment of debt and (gains) losses on sale of assets, net.

The following presents a reconciliation of net income (loss) to adjusted net income:

	Three Months Ended	
	March 31,	
	2011	2010
	(in thousands, except per unit amounts)	
Net income (loss)	\$ (446,682)	\$ 65,310
Plus:		
Unrealized (gains) losses on commodity derivatives	425,285	(33,500)
Unrealized losses on interest rate derivatives	—	15,141
Loss on extinguishment of debt	84,562	—
(Gains) losses on sale of assets, net	(858)	414
Adjusted net income	<u>\$ 62,307</u>	<u>\$ 47,365</u>
Net income (loss) per unit – basic	\$ (2.75)	\$ 0.50
Plus, per unit:		
Unrealized (gains) losses on commodity derivatives	2.62	(0.26)
Unrealized losses on interest rate derivatives	—	0.12
Loss on extinguishment of debt	0.52	—
(Gains) losses on sale of assets, net	(0.01)	—
Adjusted net income per unit – basic	<u>\$ 0.38</u>	<u>\$ 0.36</u>

Coverage Ratio Calculation

	Three Months Ended	
	March 31, 2011	December 31, 2010
	(in thousands, except unit and ratio amounts)	
Adjusted EBITDA ⁽¹⁾	\$ 209,996	\$ 220,685
Less: interest expense ⁽²⁾	(58,751)	(61,388)
Less: maintenance capital expenditures	(26,400)	(27,105)
Distributable cash flow	<u>\$ 124,845</u>	<u>\$ 132,192</u>
Distributable cash flow per unit	\$ 0.76	\$ 0.88
Distribution per unit ⁽³⁾	\$ 0.66	\$ 0.66
Units outstanding (millions)	164.8	149.7
Distribution coverage ratio	1.15x	1.34x

(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.

(3) Based on quarterly distribution of \$0.66 per unit, or \$2.64 per unit on an annualized basis.

Statements of Operations

	Three Months Ended	
	March 31,	
	2011	2010
	(in thousands, except per unit amounts)	
Revenues and other:		
Oil, natural gas and natural gas liquids sales	\$ 240,707	\$ 149,386
Gains (losses) on oil and natural gas derivatives	(369,476)	96,003
Marketing revenues	1,173	1,394
Other revenues	1,123	253
	<u>(126,473)</u>	<u>247,036</u>
Expenses:		
Lease operating expenses	45,901	31,222
Transportation expenses	5,855	4,620
Marketing expenses	809	969
General and administrative expenses	30,560	24,488
Exploration costs	445	3,861
Bad debt expenses	(38)	189
Depreciation, depletion and amortization	66,366	49,191
Taxes, other than income taxes	15,727	10,200
(Gains) losses on sale of assets and other, net	614	(322)
	<u>166,239</u>	<u>124,418</u>
Other income and (expenses):		
Loss on extinguishment of debt	(84,562)	—
Interest expense, net of amounts capitalized	(63,464)	(27,653)
Losses on interest rate swaps	—	(23,162)
Other, net	(1,746)	(601)
	<u>(149,772)</u>	<u>(51,416)</u>
Income (loss) before income taxes	(442,484)	71,202
Income tax expense	(4,198)	(5,892)
Net income (loss)	<u>\$ (446,682)</u>	<u>\$ 65,310</u>
Net income (loss) per unit:		
Basic	\$ (2.75)	\$ 0.50
Diluted	\$ (2.75)	\$ 0.50
Weighted average units outstanding:		
Basic	163,107	129,533
Diluted	163,107	129,922
Distributions declared per unit	<u>\$ 0.66</u>	<u>\$ 0.63</u>

Operating Statistics – Continuing Operations

	Three Months Ended March 31,	
	2011	2010
Average daily production:		
Natural gas (MMcf/d)	158	110
Oil (MBbls/d)	17.2	9.8
NGL (MBbls/d)	8.6	7.5
Total (MMcfe/d)	312	213
Weighted average prices (hedged): ⁽¹⁾		
Natural gas (Mcf)	\$ 8.99	\$ 9.21
Oil (Bbl)	\$ 86.24	\$ 102.39
NGL (Bbl)	\$ 45.81	\$ 45.51
Weighted average prices (unhedged): ⁽²⁾		
Natural gas (Mcf)	\$ 4.71	\$ 5.35
Oil (Bbl)	\$ 89.44	\$ 74.76
NGL (Bbl)	\$ 45.81	\$ 45.51
Average NYMEX prices:		
Natural gas (MMBtu)	\$ 4.13	\$ 5.30
Oil (Bbl)	\$ 94.10	\$ 78.72
Costs per Mcfe of production:		
Lease operating expenses	\$ 1.63	\$ 1.63
Transportation expenses	\$ 0.21	\$ 0.24
General and administrative expenses ⁽³⁾	\$ 1.09	\$ 1.28
Depreciation, depletion and amortization	\$ 2.36	\$ 2.56
Taxes, other than income taxes	\$ 0.56	\$ 0.53

⁽¹⁾ Includes the effect of realized gains on derivatives of \$56 million and \$63 million for the three months ended March 31, 2011, and March 31, 2010, respectively.

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

⁽³⁾ General and administrative expenses for the three months ended March 31, 2011, and March 31, 2010, include approximately \$5 million and \$4 million, respectively, of noncash unit-based compensation expenses. Excluding these amounts, general and administrative expenses for the three months ended March 31, 2011, and March 31, 2010, were \$0.90 per Mcfe and \$1.07 per Mcfe, respectively. This is a non-GAAP measure used by management to analyze the Company's performance.

Selected Balance Sheet Data

	March 31, 2011	December 31, 2010
	(in thousands)	
Assets:		
Total current assets	\$ 602,532	\$ 710,909
Oil and natural gas properties, net	5,223,089	4,945,468
Other property and equipment, net	109,014	104,752
Other noncurrent assets, net	132,525	172,019
Total assets	<u>\$ 6,067,160</u>	<u>\$ 5,933,148</u>
Liabilities and unitholders' capital:		
Total current liabilities	\$ 344,389	\$ 315,108
Credit facility	160,000	—
Senior notes, net	2,347,806	2,742,902
Other noncurrent liabilities	346,470	86,922
Total liabilities	<u>3,198,665</u>	<u>3,144,932</u>
Unitholders' capital	<u>2,868,495</u>	<u>2,788,216</u>
Total liabilities and unitholders' capital	<u>\$ 6,067,160</u>	<u>\$ 5,933,148</u>

Selected Cash Flow Data

	Three Months Ended March 31,	
	2011	2010
	(in thousands)	
Net cash provided by operating activities ⁽¹⁾	\$ 107,966	\$ 79,732
Net cash used in investing activities	(358,068)	(224,485)
Net cash provided by financing activities	209,425	138,651
Net decrease in cash and cash equivalents	<u>(40,677)</u>	<u>(6,102)</u>
Cash and cash equivalents:		
Beginning	<u>236,001</u>	<u>22,231</u>
Ending	<u>\$ 195,324</u>	<u>\$ 16,129</u>

⁽¹⁾ The three months ended March 31, 2010, includes premiums paid for derivatives of approximately \$15 million.

Guidance Table

	<u>Q2 2011E</u>		<u>FY 2011E</u>	
Net production and other revenues:				
Natural gas (MMcf/d)	161	- 166	166	- 175
Oil (Bbls/d)	22,052	- 22,691	21,540	- 22,771
NGL (Bbls/d)	8,568	- 8,816	9,168	- 9,692
Total (MMcf/d)	345	- 355	350	- 370
Other revenues, net (in thousands) ⁽¹⁾	\$ 1,000	- \$ 1,200	\$ 4,500	- \$ 5,500
Costs (in thousands):				
Lease operating expenses	\$ 52,000	- \$ 56,000	\$ 205,000	- \$ 215,000
Transportation expenses	6,000	- 8,000	26,000	- 30,000
Taxes, other than income taxes	20,000	- 22,000	79,000	- 85,000
Total	\$ 78,000	- \$ 86,000	\$ 310,000	- \$ 330,000
General and administrative expenses – non-GAAP ⁽²⁾	\$ 26,000	- \$ 28,000	\$ 100,000	- \$ 105,000
Depreciation, depletion and amortization	\$ 77,000	- \$ 83,000	\$ 310,000	- \$ 330,000
Costs per Mcfe (mid-point):				
Lease operating expenses	\$ 1.70		\$ 1.60	
Transportation expenses	0.22		0.21	
Taxes, other than income taxes	0.66		0.62	
Total	\$ 2.58		\$ 2.43	
General and administrative expenses – non-GAAP ⁽²⁾	\$ 0.85		\$ 0.78	
Depreciation, depletion and amortization	\$ 2.51		\$ 2.44	
Targets (mid-point) (in thousands):				
Adjusted EBITDA ⁽³⁾	\$ 245,000		\$ 985,000	
Interest expense ⁽⁴⁾	(52,500)		(220,000)	
Maintenance capital expenditures	(39,000)		(152,500)	
Distributable cash flow	\$ 153,500		\$ 612,500	
Distributable cash flow per unit ⁽⁵⁾	\$ 0.87		\$ 3.53	
Distribution per unit ⁽⁵⁾⁽⁶⁾	\$ 0.66		\$ 2.64	
Distribution coverage ratio ⁽⁵⁾⁽⁶⁾	1.32x		1.34x	
Adjusted net income per unit ⁽⁵⁾⁽⁷⁾⁽⁸⁾	\$ 0.53		\$ 2.20	
Weighted average NYMEX differentials:				
Natural gas (MMBtu)	\$ (0.10)	- \$ 0.10	\$ 0.00	- \$ 0.20
Oil (Bbl)	\$ (6.75)	- \$ (4.75)	\$ (6.00)	- \$ (4.00)
Oil (Bbl)	44%	- 48%	45%	- 49%
Unhedged commodity price assumptions:				
Natural gas (MMBtu)	\$ 4.24	\$ 4.12	\$ 4.18	\$ 4.43
Oil (Bbl)	\$ 108.88	\$ 107.01	\$ 107.51	\$ 100.00

Note: Financial and operational estimates assume closing of pending acquisitions.

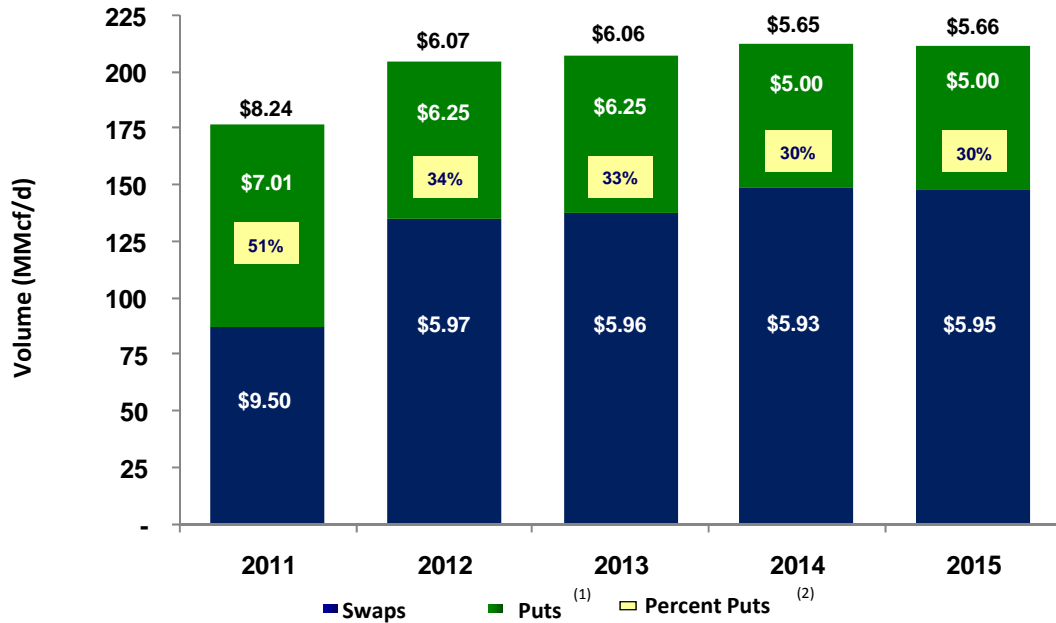
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Guidance Table – *Continued*

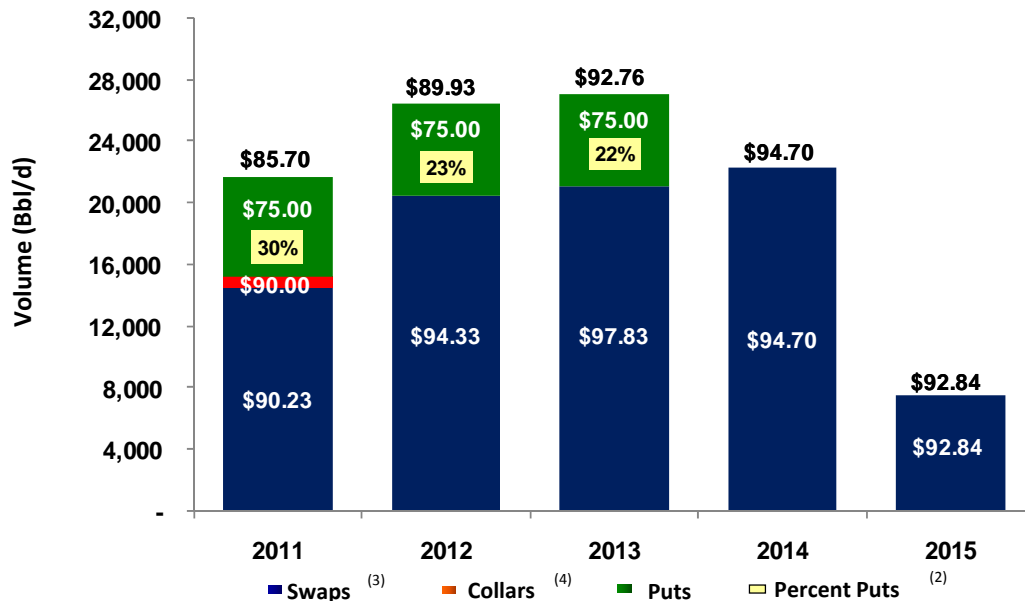
- (1) Includes other revenues and margin on natural gas marketing activities.
- (2) Excludes unit-based compensation, which represents a noncash charge based on equity-related compensation.
- (3) Includes effects of the Company's hedge positions, cash flow adjustments from acquisition and divestiture activities and other expenses.
- (4) Includes cash payments for interest and accrued interest on the Company's senior notes. Excludes the noncash amortization of deferred financing fees of approximately \$4 million in Q2 2011 and \$16 million for full year 2011. Amortization of deferred financing fees is included in interest expense on the statements of operations.
- (5) Assumes 176.8 million and 173.7 million units outstanding for Q2 2011 and full year 2011, respectively.
- (6) Based on current quarterly distribution of \$0.66 per unit, or \$2.64 per unit on an annualized basis.
- (7) Excludes unrealized (gains) losses on derivatives, realized (gains) losses on canceled derivatives, loss on extinguishment of debt, 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 Q2 2011 and \$16 million for full year 2011.

Commodity Hedge Positions

Natural Gas Positions



Oil Positions



Note: Includes full-year 2011-2015 hedging positions.

(1) Gas positions include puts which settle on the Panhandle Eastern Pipeline Index (PEPI) 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) As presented in the table above, 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

	<u>Q2 2011E</u>	<u>FY 2011E</u>
Natural gas positions:		
Fixed price swaps:		
Hedged volume (MMMBtu)	7,975	31,901
Average price (\$/MMBtu)	\$ 9.50	\$ 9.50
Puts:		
Hedged volume (MMMBtu)	4,816	19,297
Average price (\$/MMBtu)	\$ 5.99	\$ 5.98
PEPL puts: ⁽¹⁾		
Hedged volume (MMMBtu)	3,315	13,259
Average price (\$/MMBtu)	\$ 8.50	\$ 8.50
Total:		
Hedged volume (MMMBtu)	16,106	64,457
Average price (\$/MMBtu)	\$ 8.24	\$ 8.24
Oil positions:		
Fixed price swaps:		
Hedged volume (MBbls)	1,183	5,289
Average price (\$/Bbl)	\$ 88.26	\$ 90.23
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)	1,840	7,917
Average price (\$/Bbl)	\$ 84.09	\$ 85.70
Natural gas basis differential positions:		
PEPL basis swaps: ⁽¹⁾		
Hedged volume (MMMBtu)	8,885	35,541
Hedged differential (\$/MMBtu)	\$ (0.96)	\$ (0.96)

Includes positions covering production for all months within periods specified.

⁽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 Deep and Mid-Continent Shallow regions.

Commodity Hedge Portfolio

The following table summarizes open positions as of March 31, 2011, and represents, as of such date, derivatives in place through December 31, 2015, on annual production volumes:

	April 1 – December 31, 2011	2012	2013	2014	2015
Natural gas positions:					
Fixed price swaps:					
Hedged volume (MMMBtu)	23,926	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)	14,515	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)	9,944	—	—	—	—
Average price (\$/MMBtu)	\$ 8.50	\$ —	\$ —	\$ —	\$ —
Total:					
Hedged volume (MMMBtu)	48,385	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)	4,114	7,466	7,683	8,121	2,738
Average price (\$/Bbl)	\$ 90.79	\$ 94.33	\$ 97.83	\$ 94.70	\$ 92.84
Puts:					
Hedged volume (MBbls)	1,764	2,196	2,190	—	—
Average price (\$/Bbl)	\$ 75.00	\$ 75.00	\$ 75.00	\$ —	\$ —
Collars:					
Hedged volume (MBbls)	207	—	—	—	—
Average floor price (\$/Bbl)	\$ 90.00	\$ —	\$ —	\$ —	\$ —
Average ceiling price (\$/Bbl)	\$ 112.25	\$ —	\$ —	\$ —	\$ —
Total:					
Hedged volume (MBbls)	6,085	9,662	9,873	8,121	2,738
Average price (\$/Bbl)	\$ 86.19	\$ 89.93	\$ 92.76	\$ 94.70	\$ 92.84
Natural gas basis differential positions:					
PEPL basis swaps: ⁽¹⁾					
Hedged volume (MMMBtu)	26,656	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 Deep and Mid-Continent Shallow regions.

⁽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 the years ending December 31, 2015, December 31, 2016, and December 31, 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	
	March 31,	
	2011	2010
	(in thousands)	
Revenues and other	\$ (126,473)	\$ 247,036
Less:		
Unrealized (gains) losses on commodity derivatives	425,285	(33,500)
Marketing revenues	(1,173)	(1,394)
Other revenues	(1,123)	(253)
Combined revenues	<u>\$ 296,516</u>	<u>\$ 211,889</u>
Gains (losses) on commodity derivatives	\$ (369,476)	\$ 96,003
Less:		
Unrealized (gains) losses on commodity derivatives	425,285	(33,500)
Hedge revenues	<u>\$ 55,809</u>	<u>\$ 62,503</u>

Proved Reserves

As used herein, “Pro Forma Proved Reserves” represents the sum of (i) the Company’s estimated proved reserves as of December 31, 2010, (ii) the estimated proved reserves acquired in the acquisitions the Company has completed during 2011, (the “2011 Completed Acquisitions”) and (iii) the estimated proved reserves to be acquired in the Company’s currently pending acquisitions (the “2011 Pending Acquisitions”).

The following table sets forth certain information with respect to the Company’s estimated Pro Forma Proved Reserves.

Region	Pro Forma Proved Reserves (Bcfe)⁽¹⁾	% Natural Gas	% Proved Developed
Mid-Continent Deep	1,058	67%	58%
Mid-Continent Shallow	650	24%	68%
California	189	6%	94%
Permian Basin	522	22%	45%
Michigan	259	99%	87%
Williston Basin ⁽²⁾	94	10%	30%
Total	2,772	45%	62%

(1) Proved reserves were calculated using the commodity prices set forth below, which represent the unweighted average of the first-day-of-the-month prices for each of the 12-months immediately preceding the reserve report date set forth below. The reserve report date for each of the 2011 Completed Acquisitions is the first day of the month closest to the closing date of such acquisition. The reserve report date for each of the 2011 Pending Acquisitions is the anticipated closing date of such acquisition.

(2) Includes estimated proved reserves associated with the two pending Williston Basin acquisitions.

Properties	Reserve Report As of Date	Commodity Prices	
		Natural Gas (\$/MMbtu)	Oil (\$/Bbl)
Legacy Oil and Natural Gas Assets	12/31/2010	4.38	79.29
2011 Acquisitions:			
Permian 1 Acquisition (completed)	04/01/2011	4.10	83.17
Concho Acquisition (completed)	04/01/2011	4.10	83.17
Permian 2 Acquisition (completed)	04/01/2011	4.10	83.17
Bakken 2 Acquisition (pending)	05/01/2011	4.14	85.18
Bakken 3 Acquisition (pending)	05/01/2011	4.14	85.18