February 26, 2015

Northern Oil and Gas, Inc. Announces 2014 Fourth Quarter and Full Year Results

WAYZATA, Minn., Feb. 26, 2015 /PRNewswire/ -- Northern Oil and Gas, Inc. (NYSE MKT: NOG) today announced 2014 fourth quarter and full year results, year-end proved reserves, and 2015 production and capital budget guidance.

2014 HIGHLIGHTS

- Annual production increased 29% to 5.8 million barrels of oil equivalent ("Boe"), or 15,794 average Boe per day
- Fourth quarter production increased 29% year-over-year to 17,985 average Boe per day
- 2014 oil and gas sales increased 17% to $431.6 million
- Proved reserves increased 20% to 100.7 million Boe and pre-tax PV-10 reached $1.7 billion
- Added 589 gross (41.6 net) producing wells, bringing total producing wells to 2,338 gross (185.7 net)
- Year-end liquidity totaled approximately $261.3 million, comprised of $252 million of revolving credit facility availability and $9.3 million in cash
- Exited 2014 with 4.9 million total barrels hedged for 2015 and the first half of 2016 at an average swap price of $89.53 per barrel

Northern's 2014 GAAP net income was $163.7 million, or $2.69 per diluted share, compared to $53.1 million, or $0.85 per diluted share in 2013. Adjusted Net Income for 2014 was $57.5 million, or $0.95 per diluted share, as compared to $66.4 million, or $1.06 per diluted share, for 2013. Adjusted EBITDA for 2014 was $309.6 million, an increase of 16% when compared to 2013. See "Non-GAAP Financial Measures" below for additional information on these measures.

MANAGEMENT COMMENT

"I am very proud of our accomplishments during 2014," commented Northern's Chairman and Chief Executive Officer, Michael Reger. "Over the course of the year, we achieved 29% year-over-year production growth and 20% growth in our proved reserves, while maintaining a strong financial position. Our continued focus on capital discipline has driven improvements in our overall well productivity and the growth of our proved reserve base. That capital discipline, combined with our hedging position in 2015 and the first half of 2016, puts Northern in a strong liquidity position to weather the current downturn in commodity prices. We will continue to be judicious with our capital in this environment and plan to increase our investments as commodity prices improve."

2015 CAPITAL PROGRAM AND PRODUCTION GUIDANCE

Northern currently expects total 2015 capital expenditures to be approximately $140 million, down approximately 74% versus 2014 levels. This capital expenditure budget is comprised of approximately $120 million of drilling and completion capital and approximately $20 million of acreage acquisitions, workovers and other capitalized costs. This budget reflects approximately 20 net wells added to production in 2015, a portion of which were in process at the end of 2014 and partially accrued for in the 2014 capital budget. Northern will continue to high-grade its planned capital program for 2015 through concentration of its investment in its highest return projects. Northern has seen and expects to continue to see operators delaying drilling and completion operations while they wait for a reduction in service costs or an increase in commodity prices. With these expected delays, coupled with the reduced capital budget, Northern estimates 2015 total production will be flat with 2014 levels.

ACREAGE AND DRILLING UPDATE

As of December 31, 2014, Northern controlled approximately 185,018 net acres targeting the Williston Basin Bakken and Three Forks. In 2014, Northern acquired leasehold interests covering an aggregate of approximately 22,668 net mineral acres, for an average cost of $1,534 per net acre. In the fourth quarter of 2014, Northern acquired leasehold interests covering an aggregate of approximately 5,618 net mineral acres, for an average cost of $1,373 per net acre.

As of December 31, 2014, approximately 76% of Northern's North Dakota acreage position, and approximately 65% of Northern's total acreage position, was developed, held by production or held by operations.

In 2014, Northern added 41.6 net wells to production, bringing its total producing well count to 185.7 net wells as of December 31, 2014. Northern added 8.7 net wells to production in the fourth quarter of 2014.

2014 CAPITAL EXPENDITURES

During 2014, Northern's capital expenditures included approximately $479.5 million of drilling, completion and capitalized workover costs. This amount includes percentage of completion accrual amounts that are attributable to the current wells in process. In addition, during the year Northern spent $49.9 million on acreage and other acquisition activities in the Williston Basin and incurred $7.5 million of other capitalized costs.

LIQUIDITY UPDATE

Northern ended the year with $298 million drawn on its revolving credit facility, which has a total borrowing capacity of $550 million. Northern also ended the year with $9.3 million in cash, resulting in liquidity of approximately $261.3 million.

2014 YEAR-END RESERVES

Based on reports prepared by Ryder Scott Company, L.P., Northern's estimated total proved reserves at December 31, 2014 were approximately 100.7 million barrels of oil equivalent (MMBoe), a 20% increase as compared to 84.2 MMBoe at December 31, 2013. Pre-Tax PV-10 of the proved reserves as of December 31, 2014 is approximately $1.7 billion. The year-over-year increase in reserves relative to Northern's 2014 production reflects a reserve replacement ratio of 388%. Approximately 51% of Northern's reserves at December 31, 2014 are categorized as proved developed, and the reserves were 88% oil.

Additional information regarding Northern's proved reserves, including estimated future cash flows, discounted at an annual rate of 10 percent before giving effect to income taxes (commonly known as Pre-Tax PV-10 value, which may be considered a non-GAAP measure), is attached at the end of this release.

HEDGING UPDATE

The following table summarizes Northern's open crude oil swap derivative contracts as of December 31, 2014, by quarter with associated volumes.

Contract Period	Volumes (Bbl)	Weighted Average Price ($ per Bbl)
2015:		
Q1	990,000	89.03
Q2	990,000	89.03
Q3	990,000	89.82
Q4	990,000	89.82
2016:		
Q1	450,000	90.00
Q2	450,000	90.00

FULL YEAR 2014 RESULTS

The following table summarizes the full year operating and financial results for 2014 as compared to 2013:

	Year Ended December 31,		
	2014	2013	Change
Net Production:			
Oil (Bbl)	5,150,913	4,046,701	27%
Natural Gas and NGLs (Mcf)	3,682,781	2,572,251	43%
Total (Boe)	5,764,710	4,475,409	29%

Average Daily Production:			
Oil (Bbl)	14,112	11,087	27%
Natural Gas and NGLs (Mcf)	10,090	7,047	43%
Total (Boe)	15,794	12,261	29%
Average Sales Prices:			
Oil (per Bbl)	$ 79.23	$ 87.90	(10)%
Effect of loss on settled derivatives (per Bbl)	(1.53)	(3.01)	(49)%
Oil net of settled derivatives (per Bbl)	77.70	84.89	(8)%
Natural Gas and NGLs (per Mcf)	6.38	5.24	22%
Realized price per Boe[(a)]	73.51	79.77	(8)%
Average Production Costs (per Boe of production):			
Production Expenses	$ 9.66	$ 9.35	3%
Production Taxes	7.58	7.81	(3)%
General and Administrative Expense	3.05	3.70	(18)%
Depletion, Depreciation, Amortization and Accretion	29.99	27.79	8%

(a) Realized prices include realized gains or losses on cash settlements for commodity derivatives.

Oil and Natural Gas Sales

In 2014, oil, natural gas and natural gas liquids ("NGL") sales, including the effect of settled derivatives, increased 19% from 2013 to $423.7 million, driven by average production of 15,794 Boe per day, a 29% increase year-over-year. Northern's average oil price differential to the NYMEX WTI benchmark during 2014 was $13.67 per barrel, as compared to $8.68 per barrel in 2013.

Derivative Instruments

For 2014, Northern incurred a loss on settled derivatives of $7.9 million, compared to a loss of $12.2 million in 2013. Northern had a non-cash mark-to-market derivative gain of $171.3 million in 2014 compared to a $21.3 million loss in 2013.

Production Expenses

Production expenses were $55.7 million in 2014, compared to $41.9 million in 2013. Northern experiences an increase in aggregate operating expenses as it adds new wells and maintains production from existing properties. On a per unit basis, production expenses increased 3% from $9.35 per Boe in 2013 to $9.66 per Boe in 2014.

Production Taxes

Northern pays production taxes based on realized oil and natural gas sales. These costs were $43.7 million in 2014 compared to $35.0 million in 2013. Average production tax rates were 10.1% and 9.5% in 2014 and 2013, respectively. The 2014 average production tax rate was higher than the 2013 average due to fewer wells that qualified for reduced rates or tax exemptions during 2014.

General and Administrative Expense

General and administrative expense was $17.6 million for 2014 compared to $16.6 million for 2013. On a per unit basis, general and administrative expense decreased 18% to $3.05 per Boe in 2014, compared to $3.70 per Boe in 2013.

Depletion, Depreciation, Amortization and Accretion

Depletion, depreciation, amortization and accretion ("DD&A") was $172.9 million in 2014, compared to $124.4 million in 2013. Depletion expense, the largest component of DD&A, averaged $29.86 per Boe in 2014, compared to $27.62 per Boe in 2013. The increase in aggregate DD&A expense for 2014 compared to 2013 was driven by a 29% increase in production and an 8% increase in our depletion rate per Boe.

Interest Expense

Interest expense was $42.1 million for 2014 compared to $32.7 million in 2013. The increase in interest expense for 2014 as compared to 2013 was primarily due to higher weighted average debt amounts outstanding in 2014.

Income Tax Provision

The provision for income taxes was $99.4 million in 2014, compared to $31.8 million in 2013. The effective tax rate in 2014 was 37.8%, compared to an effective tax rate of 37.4% in 2013.

Net Income

Net income was $163.7 million in 2014, compared to $53.1 million in 2013. The increase in net income in 2014 as compared to 2013 was driven by a $171.3 million gain on the mark-to-market of derivative instruments, as well as higher oil and gas sales due to increased production levels. Diluted net income per common share was $2.69 in 2014, compared to $0.85 in 2013.

Non-GAAP Financial Measures

Adjusted Net Income for 2014 was $57.5 million, or $0.95 per diluted share, as compared to $66.4 million, or $1.06 per diluted share, for 2013. Northern defines Adjusted Net Income as net income excluding (i) loss (gain) on the mark-to-market of derivative instruments, net of tax, (ii) certain legal settlements, net of tax and (iii) severance expenses in connection with the 2012 departures of Northern's former president and former chief operating officer, net of tax.

Adjusted EBITDA for 2014 was $309.6 million, which represents a 16% increase over Adjusted EBITDA of $268.0 million for 2013. Northern defines Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion, amortization, and accretion, (iv) loss (gain) on the mark-to-market of derivative instruments and (v) non-cash share based compensation expense.

Adjusted Net Income and Adjusted EBITDA are non-GAAP measures. A reconciliation of these measures to their most directly comparable GAAP measure is included in the accompanying financial tables found later in this release. Management believes the use of these non-GAAP financial measures provides useful information to investors to gain an overall understanding of current financial performance. Specifically, management believes the non-GAAP results included herein provide useful information to both management and investors by excluding certain expenses and unrealized derivatives gains and losses that management believes are not indicative of Northern's core operating results. In addition, these non-GAAP financial measures are used by management for budgeting and forecasting as well as subsequently measuring Northern's performance, and management believes it is providing investors with financial measures that most closely align to its internal measurement processes.

FOURTH QUARTER 2014 RESULTS

The following tables summarize Northern's fourth quarter operating and financial results for 2014 as compared to 2013:

	Quarter Ended December 31,		
	2014	2013	Change
Net Production:			
Oil (Bbl)	1,467,212	1,155,495	27%
Natural Gas and NGLs (Mcf)	1,124,427	765,154	47%
Total (Boe)	1,654,617	1,283,021	29%
Average Daily Production:			
Oil (Bbl)	15,948	12,560	27%
Natural Gas and NGLs (Mcf)	12,222	8,317	47%
Total (Boe)	17,985	13,946	29%
Average Sales Prices:			
Oil (per Bbl)	$ 60.30	$ 82.35	(27)%
Effect of (loss) gain on settled derivatives (per Bbl)	11.74	(2.80)	
Oil net of settled derivatives (per Bbl)	72.04	79.55	(9)%
Natural Gas and NGLs (per Mcf)	5.32	5.23	2%
Realized price per Boe[(a)]	67.49	74.77	(10)%
Average Production Costs (per Boe of production):			
Production Expenses	$ 9.83	$ 8.85	11%
Production Taxes	5.80	7.53	(23)%
General and Administrative Expense	2.98	3.51	(15)%
Depletion, Depreciation, Amortization and Accretion	29.57	30.34	(3)%

(a) Realized prices include realized gains or losses on cash settlements for commodity derivatives.

Oil and Natural Gas Sales

In the fourth quarter of 2014, oil, natural gas and NGL sales, including the effect of settled derivatives, increased 16% year-over-year to $111.7 million, driven by a 29% year-over-year increase in average daily production to 17,985 Boe per day. Northern's average oil price differential to the NYMEX WTI benchmark during the fourth quarter of 2014 was $12.89 per barrel, as compared to $14.98 per barrel in the fourth quarter of 2013.

Derivative Instruments

For the fourth quarter of 2014, Northern incurred a net cash settlement gain of $17.2 million, compared to a loss of $3.2 million in the fourth quarter of 2013. Northern had a non-cash mark-to-market derivative gain of $145.8 million in the fourth quarter of 2014 compared to non-cash gain of $6.0 million in the fourth quarter of 2013.

Production Expenses

Production expenses were $16.3 million in the fourth quarter of 2014, compared to $11.3 million in the fourth quarter of 2013. Northern experiences an increase in aggregate operating expenses as it adds new wells and maintains production from existing properties. On a per unit basis, production expenses increased from $8.85 per Boe in the fourth quarter of 2013 to $9.83 per Boe in the fourth quarter of 2014.

Production Taxes

Northern pays production taxes based on realized oil and gas sales. These costs were $9.6 million in the fourth quarter of 2014, compared to $9.7 million in the fourth quarter of 2013. Average production tax rates were 10.2% in the fourth quarter of 2014 and 9.7% in the fourth quarter of 2013. The 2014 average production tax rate was higher than the 2013 average due to fewer wells that qualified for reduced rates or tax exemptions during 2014.

General and Administrative Expense

General and administrative expense was $4.9 million for the fourth quarter of 2014, compared to $4.5 million for the fourth quarter of 2013. On a per unit basis, general and administrative expense decreased 15% to $2.98 per Boe in the fourth quarter of 2014, compared to $3.51 per Boe in the fourth quarter of 2013.

Depletion, Depreciation, Amortization and Accretion

DD&A was $48.9 million in the fourth quarter of 2014, compared to $38.9 million in the fourth quarter of 2013. Depletion expense, the largest component of DD&A, was $29.45 per Boe in the fourth quarter of 2014, compared to $30.02 per Boe in the fourth quarter of 2013. Northern's depletion rate for the fourth quarter was adjusted in connection with completion of Northern's 2014 year-end reserve report.

Income Tax Provision

The provision for income taxes was $63.0 million in the fourth quarter of 2014, compared to $10.5 million in the fourth quarter of 2013. The effective tax rate in the fourth quarter of 2014 was 37.8%, compared to an effective tax rate of 37.6% in the fourth quarter of 2013.

Net Income

Net income was $103.6 million in the fourth quarter of 2014, compared to $17.4 million in the fourth quarter of 2013. The increase in net income in the fourth quarter of 2014 was primarily driven by a $90.8 million gain on the mark-to-market of derivative instruments, net of tax. Diluted net income per common share was $1.71 in the fourth quarter of 2014, compared to $0.28 in the fourth quarter of 2013.

Non-GAAP Financial Measures

Adjusted Net Income for the fourth quarter of 2014 was $12.8 million, or $0.21 per diluted share, as compared to $13.7 million, or $0.22 per diluted share, for the fourth quarter of 2013. Northern defines Adjusted Net Income as net income excluding (i) loss (gain) on the mark-to-market of derivative instruments, net of tax, (ii) certain legal settlements, net of tax and (iii) severance expenses in connection with the 2012 departures of Northern's former president and former chief operating officer, net of tax.

Northern's Adjusted EBITDA for the fourth quarter of 2014 was $81.6 million, which represents a 14% increase over Adjusted EBITDA of $71.7 million for the fourth quarter of 2013. Northern defines Adjusted EBITDA as net income before (i) interest expense, (ii) income taxes, (iii) depreciation, depletion, amortization, and accretion, (iv) (loss) gain on the mark-to-market of derivative instruments and (v) non-cash share based compensation expense.

Adjusted Net Income and Adjusted EBITDA are non-GAAP measures. A reconciliation of these measures to the most directly comparable GAAP measure is included in the accompanying financial tables found later in this release.

FOURTH QUARTER AND FULL-YEAR 2014 EARNINGS RELEASE CONFERENCE CALL

In conjunction with Northern's release of its financial and operating results, investors, analysts and other interested parties are invited to listen to a conference call with management on Friday, February 27, 2015 at 10:00 a.m. Central Standard Time. Details for the conference call are as follows:

Conference Call and Webcast Details:

Date:	Friday, February, 27, 2015
Time:	10:00 a.m. Central Time
Webcast:	www.northernoil.com
Dial-In:	855-638-5677
International Dial-In:	262-912-4762
Conference ID:	88433362

Replay Information:

Dial-In:	855-859-2056
International Dial-In:	404-537-3406
Conference ID:	88433362

A replay of the conference call will be available through March 13, 2015.

UPCOMING CONFERENCE SCHEDULE

43rd Annual Howard Weil Energy Conference
March 22 – March 26, 2015, New Orleans, LA

IPAA Oil and Gas Investment Symposium
April 7 – April 9, 2015, New York, NY

ABOUT NORTHERN OIL AND GAS, INC.

Northern Oil and Gas, Inc. is an exploration and production company with a core area of focus in the Williston Basin Bakken and Three Forks play in North Dakota and Montana.

More information about Northern Oil and Gas, Inc. can be found atwww.NorthernOil.com.

SAFE HARBOR

This press release contains forward-looking statements regarding future events and future results that are subject to the safe harbors created under the Securities Act of 1933 (the "Securities Act") and the Securities Exchange Act of 1934 (the "Exchange Act"). All statements other than statements of historical facts included in this release regarding Northern's financial position, business strategy, plans and objectives of management for future operations, industry conditions, and indebtedness covenant compliance are forward-looking statements. When used in this release, forward-looking statements are generally accompanied by terms or phrases such as "estimate," "project," "predict," "believe," "expect," "anticipate," "target," "plan," "intend," "seek," "goal," "will," "should," "may" or other words and similar expressions that convey the uncertainty of future events or outcomes. Items contemplating or making assumptions about actual or potential future sales, market size, collaborations, and trends or operating results also constitute such forward-looking statements.

Forward-looking statements involve inherent risks and uncertainties, and important factors (many of which are beyond Northern's control) that could cause actual results to differ materially from those set forth in the forward-looking statements, including the following: changes in crude oil and natural gas prices, the pace of drilling and completions activity on Northern's properties, Northern's ability to acquire additional development opportunities, changes in our reserves estimates or the value thereof, general economic or industry conditions, nationally and/or in the communities in which Northern conducts business, changes in the interest rate environment, legislation or regulatory requirements, conditions of the securities markets, Northern's ability to raise or access capital, changes in accounting principles, policies or guidelines, financial or political instability, acts of war or terrorism, and other economic, competitive, governmental, regulatory and technical factors affecting Northern's operations, products, services and prices.

Northern has based these forward-looking statements on its current expectations and assumptions about future events. While management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond Northern's control.

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NORTHERN OIL AND GAS, INC.
STATEMENTS OF COMPREHENSIVE INCOME

	Three Months Ended December 31,		Year Ended December 31,	
	2014	2013	2014	2(
REVENUES				
Oil and Gas Sales	$ 94,455,404	$ 99,160,226	$ 431,605,015	$ 369,
Gain (Loss) on Settled Derivatives	17,221,245	(3,232,459)	(7,863,104)	(12,
Gains (Losses) on the Mark-to-Market of Derivative Instruments	145,842,035	5,995,130	171,275,719	(21,
Other Revenue	3,249	6,888	9,112	
Total Revenue	257,521,933	101,929,785	595,026,742	335,
OPERATING EXPENSES				
Production Expenses	16,267,608	11,348,887	55,695,615	41,
Production Taxes	9,600,928	9,655,169	43,674,010	34,
General and Administrative Expense	4,924,823	4,507,001	17,602,306	16,
Depletion, Depreciation, Amortization and Accretion	48,924,152	38,927,949	172,883,554	124,
Total Expenses	79,717,511	64,439,006	289,855,485	217,
INCOME FROM OPERATIONS	177,804,422	37,490,779	305,171,257	117,
OTHER INCOME (EXPENSE)				
Other Income (Expense)	1,573	(16,210)	47,364	(
Interest Expense, Net of Capitalization	(11,255,673)	(9,568,631)	(42,105,676)	(32,
Total Other Income (Expense)	(11,254,100)	(9,584,841)	(42,058,312)	(33,
INCOME BEFORE INCOME TAXES	166,550,322	27,905,938	263,112,945	84,
INCOME TAX PROVISION	62,967,000	10,505,000	99,367,000	31,
NET INCOME	$ 103,583,322	$ 17,400,938	$ 163,745,945	$ 53,
OTHER COMPREHENSIVE INCOME, NET OF TAX	-	-	-	

COMPREHENSIVE INCOME	$ 103,583,322	$ 17,400,938	$ 163,745,945	$ 53,
Net Income Per Common Share – Basic	$ 1.71	$ 0.28	$ 2.70	$
Net Income Per Common Share – Diluted	$ 1.71	$ 0.28	$ 2.69	$
Weighted Average Shares Outstanding – Basic	60,507,569	61,219,556	60,691,701	62,
Weighted Average Shares Outstanding – Diluted	60,594,083	61,575,358	60,860,769	62,

NORTHERN OIL AND GAS, INC.
BALANCE SHEETS

	December 31,	
	2014	**2013**
CURRENT ASSETS		
Cash and Cash Equivalents	$ 9,337,512	$ 5,687,16
Trade Receivables	85,931,719	86,816,98
Advances to Operators	930,034	618,78
Prepaid and Other Expenses	895,088	770,74
Derivative Instruments	128,893,220	62,89
Deferred Tax Asset	-	10,431,00
Total Current Assets	225,987,573	104,387,56
PROPERTY AND EQUIPMENT		
Oil and Natural Gas Properties, Full Cost Method of Accounting		
Proved	2,167,452,297	1,611,073,74
Unproved	50,642,433	70,148,34
Other Property and Equipment	1,870,369	1,701,36
Total Property and Equipment	2,219,965,099	1,682,923,46
Less - Accumulated Depreciation and Depletion	(458,038,546)	(285,616,75
Total Property and Equipment, Net	1,761,926,553	1,397,306,70
DERIVATIVE INSTRUMENTS	25,013,011	1,745,40
DEBT ISSUANCE COSTS	13,819,195	16,160,28
TOTAL ASSETS	$ 2,026,746,332	$ 1,519,599,96

LIABILITIES AND STOCKHOLDERS' EQUITY

CURRENT LIABILITIES		
Accounts Payable	$ 231,557,547	$ 168,936,78
Accrued Expenses	6,653,124	2,645,17
Accrued Interest	3,585,536	3,386,40
Derivative Instruments	-	19,119,64
Deferred Tax Liability	43,938,000	

Total Current Liabilities	285,734,207	194,088,01
LONG-TERM LIABILITIES		
Revolving Credit Facility	298,000,000	75,000,00
8% Senior Notes	508,053,097	509,539,82
Derivative Instruments	579,070	637,20
Other Noncurrent Liabilities	5,105,762	3,832,55
Deferred Tax Liability	158,412,555	116,674,00
Total Long-Term Liabilities	970,150,484	705,683,58
TOTAL LIABILITIES	1,255,884,691	899,771,59
COMMITMENTS AND CONTINGENCIES (NOTE 8)		
STOCKHOLDERS' EQUITY		
Preferred Stock, Par Value $.001; 5,000,000 Authorized, No Shares Outstanding	-	
Common Stock, Par Value $.001; 95,000,000 Authorized (12/31/2014 – 61,066,712 Shares Outstanding and 12/31/2013 – 61,858,199 Shares Outstanding)	61,067	61,85
Additional Paid-In Capital	433,332,285	446,044,15
Retained Earnings	337,468,289	173,722,34
Total Stockholders' Equity	770,861,641	619,828,36
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 2,026,746,332	$ 1,519,599,96

Reconciliation of Adjusted Net Income

	Three Months Ended December 31,		Year Ended December 31,	
	2014	**2013**	**2014**	**2013**
	(in thousands, except share and per common share data)			
Net Income	$ 103,583	$ 17,401	$ 163,746	$ 53,06
Add:				
(Gain) Loss on the Mark-to-Market of Derivative Instruments, Net of Tax[(a)]	(90,757)	(3,753)	(106,585)	13,30
Severance Expense, Net of Tax[(b)]	-	-	-	-
Legal Settlements, Net of Tax[(c)]	-	-	360	-
Adjusted Net Income	$ 12,826	$ 13,648	$ 57,521	$ 66,36

Weighted Average Shares Outstanding – Basic	60,507,569	61,219,556	60,691,701	62,364,957
Weighted Average Shares Outstanding – Diluted	60,594,083	61,575,358	60,860,769	62,747,29
Net Income Per Common Share – Basic	$ 1.71	$ 0.28	$ 2.70	$ 0.8
Add:				
Change due to (Gain) Loss on the Mark-to-Market of Derivative Instruments, Net of Tax	(1.50)	(0.06)	(1.76)	0.2
Change due to Severance Expense, Net of Tax	-	-	-	-
Change due to Legal Settlements, Net of Tax	-	-	.01	
Adjusted Net Income Per Common Share – Basic	0.21	$ 0.22	$ 0.95	$ 1.0
Net Income Per Common Share – Diluted	$ 1.71	$ 0.28	$ 2.69	$ 0.8
Add:				
Change due to (Gain) Loss on the Mark-to-Market of Derivative Instruments, Net of Tax	(1.50)	(0.06)	(1.75)	0.2
Change due to Severance Expense, Net of Tax	-	-	-	-
Change due to Legal Settlements, Net of Tax	-	-	.01	-
Adjusted Net Income Per Common Share – Diluted	0.21	$ 0.22	$ 0.95	$ 1.0

(a) Adjusted to reflect related tax benefit (expense) of $55.1 million and $2.2 million for the three months ended December 31, 2014 and 2013, respectively and $64.7 million and ($8.0 million) for the years ended December 31, 2014 and 2013 respectively.
(b) Reflects severance expense recognized in connection with the departures during 2012 of our former president and former chief operating officer. Adjusted to reflect related tax benefit of $2.0 million, for the year ended December 31, 2012.
(c) Reflects legal expense recognized in connection with legal settlement for the year ended December 31, 2014. Adjusted to reflect related tax benefit of $0.2 million.

Reconciliation of Adjusted EBITDA

	Three Months Ended December 31,		Year Ended December 31,	
	2014	**2013**	**2014**	**20**
		(in thousands)		
Net Income	$ 103,583	$ 17,401	$ 163,746	$
Add Back:				

Interest Expense	11,256	9,569	42,106	3
Income Tax Provision	62,967	10,505	99,367	3
Depreciation, Depletion, Amortization and Accretion	48,924	38,928	172,884	12
Non-Cash Share Based Compensation	737	1,251	2,759	
Loss (Gain) on the Mark-to-Market of Derivative Instruments	(145,842)	(5,995)	(171,276)	2
Adjusted EBITDA	$ 81,625	$ 71,659	$ 309,586	$ 2

Proved Reserve Summary at December 31, 2014[1]

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe)[2]	Pre-Tax PV10% Value $M[3]
PDP Properties	35,084	30,502	40,167	$ 1,129,152
PDNP Properties	9,582	7,776	10,879	117,144
PUD Properties	44,247	32,657	49,690	455,928
Total Proved Properties:	88,913	70,935	100,736	$ 1,702,224

(1) The SEC Pricing Proved Reserves table above values oil and natural gas reserve quantities and related discounted future net cash flows as of December 31, 2014 assuming constant realized prices of $83.11 per barrel of oil and $7.37 per Mcf of natural gas, which includes an uplift factor of 1.7 to reflect liquids and condensates (natural gas liquids are included with natural gas). Under SEC guidelines, these prices represent the average prices per barrel of oil and per Mcf of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period, which averages are then adjusted to reflect applicable transportation and quality differentials.
(2) Boe are computed based on a conversion ratio of one Boe for each barrel of oil and one Boe for every 6,000 cubic feet (i.e., 6 Mcf) of natural gas.
(3) Pre-tax PV10%, or "PV-10," may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP measure.

The table above assumes prices and costs discounted using an annual discount rate of 10% without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or federal income taxes. The information in the table above does not give any effect to or reflect our commodity derivatives.

The "Pre-tax PV10%" values of our proved reserves presented in the foregoing table may be considered a non-GAAP financial measure as defined by the SEC. PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves. The following table reconciles the pre-tax PV10% value of our SEC Pricing Proved Reserves to the Standardized Measure of discounted future net cash flows.

SEC Pricing Proved Reserves		
Standardized Measure Reconciliation		
Pre-Tax Present Value of Estimated Future Net Revenues (Pre-Tax PV10%)	$	1,702,223,625
Future Income Taxes, Discounted at 10%		296,844,082
Standardized Measure of Discounted Future Net Cash Flows	$	1,405,379,543

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner. As a result, estimates of proved reserves may vary depending upon the engineer valuing the reserves. Further, our actual realized price for our oil and natural gas is not likely to average the pricing parameters used to calculate our proved reserves. As such, the oil and natural gas quantities and the value of those commodities ultimately recovered from our properties will vary from reserve estimates.