Lone Pine Resources Inc.
Lone Pine Resources Canada Ltd.

Management's Discussion and Analysis
For the Three Months and Year Ended December 31, 2015

Dated: April 5, 2016

Advisories

The following management's discussion and analysis ("MD&A") of Lone Pine Resources Inc. ("Lone Pine Resources") and Lone Pine Resources Canada Ltd. ("LPR Canada"; collectively "Lone Pine" or the "Company") provides management's analysis of the Company's results of operations, financial position and outlook as at and for the three and twelve months ended December 31, 2015. This MD&A is dated April 5, 2016 and should be read in conjunction with the audited combined and consolidated financial statements of Lone Pine as at and for the year ended December 31, 2015 (the "2015 Annual Financial Statements").

The financial information presented in this MD&A has been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (IASB) unless otherwise noted.

Unless otherwise noted, all financial information provided herein is reported in Canadian dollars. Production volumes are presented on a working-interest basis, before royalties.

This MD&A contains forward-looking statements and non-IFRS measures. Readers are cautioned that the MD&A should be read in conjunction with Lone Pine's disclosures under the headings "Forward-Looking Statements" and "Non-IFRS Measures" included at the end of this MD&A.

Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mboe	thousands of barrels of oil equivalent
mmboe	millions of barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	million British Thermal Units
GJ	gigajoule

AECO	AECO "C" hub price index for Alberta natural gas
CGU	cash-generating-unit
DD&A	depreciation, depletion and amortization
E&E	exploration and evaluation
GAAP	generally accepted accounting principles
G&A	general and administrative
IFRS	International Financial Reporting Standards
P&D	production and development
RSU	restricted share unit
WTI	West Texas Intermediate

Report to the Shareholders

The year 2015 has marked one of the most challenging years for the oil and gas business. Global oversupply of crude oil continued to weigh on the market, eventually pushing prices below to US$30/bbl in early 2016. As the year unfolded, oil and gas development economics were increasingly pressured, funds from operations declined considerably, and balance sheet strength and liquidity became of utmost importance.

Despite these turbulent times, we delivered strong operating results in 2015 through cost reduction efforts and prudent operations. We achieved annual average production of 2,652 boe/d, coming in at the high end of our production guidance. Though we shut-in certain un-economic production, the effect was largely offset by higher production at Evi due to exceptional run rates and waterflood responses. Our strong performance was supported by our robust commodity hedging program, which generated realized cash gains of $16.8 million during the year, resulting in 2015 EBITDAX of approximately $26.6 million. We ended the year with $13 million of cash on hand. In addition, our $50 million credit facility remained undrawn, which was renewed in 2015 with a maturity date of May 31, 2017.

Our solid operational performance and stable liquidity position allowed us to expand our business. In 2015, we established a second core area – Wheatland area – through a lease acquisition agreement and then a farm-in arrangement. The multi-stacked pay zones in the Wheatland Area provide attractive development prospects. Lone Pine has identified over 125 drilling locations mainly targeting the Lithic Glauconite, Ellerslie, Basal Quartz, and Turner Valley Formations. Since September 2015, we have drilled 7 wells at Wheatland, taking advantage of the down cycle pricing. The initial 4 wells showed an average IP30 of 294 boe/d. The remaining 3 wells do not have IP30 data yet, however, the test data shows encouraging results.

Through prudent operations of our existing assets and acquisition of the Wheatland area, we built strong foundations for long-term growth by delivering solid reserves performance in 2015, successfully replacing 2015 production with proved plus probable (2P) reserve additions. As at December 31, 2015, the Company had an estimated 12.3 MMboe (75% liquids) of 2P reserves with a NPV10 of $162.5 million. 2015 2P reserves increased by 10% or 1.14 MMboe from 2014. Based on 2P reserves additions[1] of 2.1 MMboe, a replacement ratio of 220% was achieved. F&D[2] costs (excluding FDC)[3] was $10.01/boe, resulting in recycle ratio of 2.2. The significant reserve additions came from the drilling program at the Wheatland area. We also had reserves bookings from the Evi waterflood program that has shown positive responses. These two areas represent future value creation in the Company and for our shareholders.

In 2016, we plan to continue proving up the Wheatland prospects in a fiscally disciplined manner, by closely monitoring the drilling economics. We also plan to expand our waterflood program by converting 4 producers to injectors. We remain well hedged in 2016 with a significant portion of our crude oil and natural gas production protected at prices well in excess of the current market prices. In addition, our strong balance sheet provides us with the financial flexibility to pursue both organic growth and M&A opportunities to provide accretive value to our shareholders.

We remain committed to preserving financial liquidity through this downturn. We continue to take active measures to reduce costs while maintaining the efficiency and compliance of our operations and the integrity of our assets without compromising the safety of our workforce. We strongly believe the efforts we demonstrated in 2015 and

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[1] Includes extensions, infills, improved recovery, technical revisions and economic factors.
[2] Calculated using exploration and development costs incurred in 2015 and 2P reserves additions.
[3] The downward change in FDC, which exceeded the 2015 capital spent, resulted in negative exploration and development expenditures, therefore F&D costs including FDC are not meaningful.

the actions we have taken in 2016 are the appropriate ones to ensure that the Company remains financially sound and emerges from this downturn a stronger company.

Lone Pine Overview

Lone Pine is a Canadian independent oil and gas exploration, development and production company, headquartered in Calgary, Alberta, Canada. The Company's reserves, producing properties and exploration prospects are located in the provinces of Alberta, British Columbia and Quebec, and the Northwest Territories.

Recent Developments

2015

On June 30, 2015, LPR Canada entered into a lease acquisition agreement for mineral leases covering approximately 69,000 net acres of undeveloped lands in the Wheatland area in southeast Alberta. The mineral leases generally have a primary term of three years, with a three-year extension option. In exchange for the leases, LPR Canada paid $9.3 million of cash consideration.

Effective December 8, 2015, Lone Pine entered into a farm-in and option agreement to farm-in certain lands in the Wheatland area.

Corporate History

2014

On January 31, 2014, the Company implemented the Plan and emerged from the Creditor Protection Proceedings. Implementation of the Plan (as herein defined) resulted in comprehensive capital reorganization and financial restructuring of the Company. Lone Pine became a private entity and the Company's financial position at December 31, 2014, had improved significantly, compared with the prior year.

On August 12, 2014, LPR Canada sold all the assets within its Deep Basin CGU for cash proceeds of $110.4 million net of disposition costs. The Deep Basin CGU was comprised of gas-weighted undeveloped and developed properties in the Narraway and Ojay fields, located in Alberta and British Columbia. The disposition resulted in approximately $2.0 million gain on sale of property and equipment for the year 2014. Proceeds from the disposition were used to fully repay Lone Pine's borrowings under its outstanding credit facilities. This provides the Company with financial flexibility to pursue various strategic options.

2013

On September 25, 2013, the Company commenced proceedings under the Companies' Creditors Arrangement Act ("CCAA") in the Court of Queen's Bench of Alberta (the "CCAA Court") and ancillary proceedings under Chapter 15 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware (the "U.S. Bankruptcy Court"). Lone Pine Resources, LPR Canada and all other subsidiaries of the Company were parties to the CCAA and Chapter 15 proceedings (collectively, the "Creditor Protection Proceedings").

On January 9, 2014, the CCAA Court issued an order (the "Sanction Order") sanctioning and approving Lone Pine's previously announced first amended and restated plan of compromise and arrangement (the "Plan") under the CCAA. On January 10, 2014, the U.S. Bankruptcy Court issued an order recognizing and enforcing the Sanction Order in the United States under Chapter 15 of the U.S. Bankruptcy Code.

The Business Environment

Lone Pine's operations are influenced by both international and domestic factors. The Company is exposed to a number of risks inherent in the exploration, development, production, marketing, transportation, storage and sale of oil and gas. Commodity price fluctuations and declines, particularly as experienced with North American commodity prices, are highly dependent on international supply and economic conditions and represent one of the most significant factors that affect the performance of the Company and its financial position. The Company enters into commodity derivatives to help mitigate price volatility (see Commodity Price and Risk Management).

The over-supplied oil and natural gas market became prevalent in late 2014, as a result of the continued production growth from shale plays in the United States, slower than expected global demand growth, and sustained production levels by OPEC. The severe crude oil supply-demand imbalance persisted in 2015 and continued into the start of 2016. With new Iranian production and looming economic slowdown in China, WTI prices have been pushed to 11-year lows. Current oil prices are below marginal supply costs for new production from many areas; resulting in major capital spending cuts globally in 2015 and in 2016. While reduced capital activity is expected to re-balance markets, the existing production and storage will take some time to be depleted. The decreased capital activities have resulted in lower oilfield service costs, which has improved production economics somewhat.

Due to significant drop in commodity prices, the Canadian dollar has also been facing downward pressure. The CDN$/US$ exchange rate has been dropping considerably in 2015. The devaluation of the Canadian dollar relative to the US dollar partially offsets the impact of lower US dollar-denominated crude oil and natural gas prices.

Outlook

Lone Pine started 2016 with a strong balance sheet, a positive cash position and no borrowings under its $50 million reserve-based credit facility. We remain committed to preserving financial liquidity through this downturn. We continue to take active measures to reduce costs while maintaining the efficiency and compliance of our operations in order to navigate the current pricing environment. In 2016, we plan to continue proving up the Wheatland prospects, and will do so in a fiscally disciplined manner by closely monitoring the drilling economics. We also plan to expand our waterflood program by converting 4 producers to injectors. We remain well hedged in 2016, and protected at prices well in excess of the current market prices. In addition, our strong balance sheet provides us with the financial flexibility to pursue both organic growth and M&A opportunities to provide accretive value to our shareholders.

For 2016, Lone Pine has hedged approximately 60% (2015 – 82%) of its forecast oil production and 44% (2015 – nil) of its gas production (from producing properties at December 31, 2015, net of royalties), at $84.64/bbl (2015 – $95.66/bbl) and $2.50/GJ, respectively. Annual production is forecast to be slightly below 3,500 boe/d, with 67% in liquids. Compared against 2015 exit production of 2,777 boe/d, 2016 forecast includes wedge volume from the 12-well drilling program at the Wheatland area. EBITDAX for the year of 2016 is expected to be approximately $12.6 million, a $14.0 million decrease from 2015. Lower 2016 commodity prices are the key contributors to the decreased EBITDAX for 2015, despite higher production volume. Lone Pine planned to invest $32.7 million on Wheatland drilling, Evi waterflood project, non-drilling capital projects and asset retirement activities, which will be primarily funded by its cash flows from operations, existing cash on hand and borrowings from the credit facility.

Financial and Operational Highlights

	Three Months Ended December 31,		Year Ended December 31,	
($000s except per unit amounts)	**2015**	2014	**2015**	2014
Financial				
Oil and natural gas revenue	**8,783**	16,323	**39,335**	111,467
EBITDAX[4]	**7,138**	9,115	**26,582**	45,779
Net loss	**(15,390)**	(127,211)	**(59,894)**	(73,395)
Net capital expenditures (dispositions)	**9,809**	(1,540)	**24,627**	(66,356)
Production Volumes				
Crude oil (bbls/d)	**1,799**	2,197	**1,820**	2,257
Natural gas (Mcf/d)	**4,130**	4,937	**4,577**	21,489
Natural gas liquids (bbls/d)	**63**	81	**69**	86
Total (boe/d)	**2,550**	3,101	**2,652**	5,924
% Liquids	**73%**	73%	**71%**	40%
Average Realized Prices				
Crude oil ($/bbl)	**46.58**	71.31	**51.24**	89.42
Natural gas ($/Mcf)	**2.56**	3.58	**3.01**	4.62
Natural gas liquids ($/bbl)	**17.08**	37.74	**10.76**	50.25
Total ($/boe)	**37.44**	57.21	**40.64**	51.55
Operating Netback ($/boe)[5]				
Realized price	**37.44**	57.21	**40.64**	51.55
Royalties	**(3.18)**	(6.83)	**(2.26)**	(6.22)
Operating costs	**(15.92)**	(22.62)	**(16.49)**	(16.55)
Operating netback	**18.34**	27.76	**21.89**	28.78

2015 highlights include:

- In the June 2015, Lone Pine entered into a lease acquisition agreement for mineral leases covering approximately 69,000 net acres of undeveloped land in the Wheatland area in southeast Alberta. In exchange for the leases, LPR Canada paid $9.3 million of cash consideration. The lands were purchased with the intention to establish Wheatland into the Company's second core area.

- In December 2015, Lone Pine entered into a farm-in and option arrangement, where the Company may earn additional lands in the Wheatland area. This farm-in arrangement reinforces Lone Pine's strategy to establish Wheatland as its second core area. Not only the arrangement will increase the Company's land holdings, it is also expected to high-grade the Company's drilling prospects.

- In September 2015, Lone Pine commenced its initial four-well drilling program at the Wheatland area. Two wells were spudded in the third quarter, with the remaining two spudded in the fourth quarter.

- Production averaged 2,652 boe/d (71% liquids), a 55% decrease compared to 2014 due to the 2014 Deep Basin CGU sale, natural declines and the shut-in of certain un-economic wells since May 2015. Production declines were partially offset by additions from the 2015 drilling program, with one well coming on production in

[4,5] EBITDAX and Operating Netback are non-IFRS measures and are defined in Other Advisories.

December 2015 resulting in an increase in fourth quarter production of approximately 140 boe/d. Excluding the Deep Basin 2014 production, average production decreased by 724 boe/d or 21% compared to 2014.

- Operating netback after realized gains on derivative instruments was $39.23/boe for 2015, an increase of $13.56/boe from 2014. The higher operating netback was primarily due to $17.34/boe of realized gains on derivative instruments recognized in 2015, as compared to $3.11 of realized losses on derivative instruments in 2014. The increase in realized gains on derivative instruments offset the $10.91/boe decrease in average realized prices. Lone Pine's overall average realized prices did not decrease to the same extent as decreases in benchmark prices because the Company benefited from higher liquids-weighted production mix after the Deep Basin disposition in 2014. The remaining $4.02/boe of favorable variance was mainly attributable to lower royalties rate, a direct result of lower commodity prices.

- EBITDAX was $26.6 million, a $19.2 million decrease compared to 2014, mainly due to lower production, partially offset by higher operating netback after realized gains on derivative instruments.

- Capital expenditures, net of proceeds from dispositions, were $24.6 million, which included $9.3 million of cash consideration paid for the Wheatland lands and $10.8 million spent on the Wheatland drilling program.

- Net loss was $59.9 million, compared to a net loss of $73.4 million in 2014. During 2015, the Company recognized $25.5 million of unrealized foreign exchange losses substantially related to the US dollar denominated preferred shares. Additionally, impairment losses of $10.5 million were recorded in 2015 against E&E assets as a result of changes in management development plans due to significant and prolonged decreases in commodity prices, as well as to impair increases in decommissioning liability assets related to assets that were previously written-off. The 2014 net loss included $162.5 million of impairment losses related to E&E and P&D assets offset by a $104.9 million gain on the extinguishment of financial liabilities.

- Exited the year with working capital of $18.3 million (including $13.0 million in cash) and no borrowings.

- On July 30, 2015, the Company entered into an amended and restated credit agreement with the same syndicate lenders, under which (a) a $40 million syndicated facility and (b) a $10 million operating facility are available (collectively, the "Amended Credit Facility"). Future borrowings under the Amended Credit Facility will bear lower margins than under the previous agreement.

Fourth quarter highlights include:

- Average production of 2,550 boe/d, (73% liquids) decreased by 18% from the fourth quarter of 2014 mainly due to natural production declines and the shut-in of certain un-economic wells since May 2015. Production declines were partially offset by new production from Wheatland drilling;

- EBITDAX of $7.1 million, compared with $9.1 million in the same quarter in 2014. The decrease was the result of lower production in 2015;

- Capital expenditures were $9.8 million in the fourth quarter, which include $8.5 million on the Wheatland drilling program; and

- Impairment losses of $7.3 million were recorded related to E&E assets.

Results of Operations

Production

	Three Months Ended December 31,		Year Ended December 31,	
	2015	2014	**2015**	2014
Crude oil (bbls/d)	**1,799**	2,197	**1,820**	2,257
Natural gas (Mcf/d)	**4,130**	4,937	**4,577**	21,489
Natural gas liquids (bbls/d)	**63**	81	**69**	86
Total (boe/d)	**2,550**	3,101	**2,652**	5,924
Oil & Liquids Weighting	**73%**	73%	**71%**	40%

The Company's production in the fourth quarter of 2015 decreased by 18% compared to the fourth quarter of 2014. The decrease was primarily the result of natural production declines, coupled with the shut-in of certain uneconomic wells since May 2015. Under the 2014 drilling program, 10 of the 11 wells that were drilled in the Evi area commenced production during March and April of 2014. New wells typically have sharper decline rates in the first year of production, which contributed to the significant variance between the two periods. The production declines were partially offset by additions from the 2015 drilling program, with one well coming on production in December 2015 resulting in an increase in fourth quarter production of approximately 140 boe/d.

The 2015 annual production decreased by 55% compared to 2014 annual production. The most significant decrease was the 79% decrease in natural gas production due primarily to the Deep Basin CGU disposition in August 2014. The remainder of the decrease was the result of the factors outlined above.

Revenue

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per unit amounts)	**2015**	2014	**2015**	2014
Revenue				
Crude oil	**7,710**	14,416	**34,041**	73,656
Natural gas	**974**	1,626	**5,023**	36,230
Natural gas liquids	**99**	281	**271**	1,581
Oil and natural gas revenue	**8,783**	16,323	**39,335**	111,467
Average Realized Prices				
Crude oil ($/bbl)	**46.58**	71.31	**51.24**	89.42
Natural gas ($/Mcf)	**2.56**	3.58	**3.01**	4.62
Natural gas liquids ($/bbl)	**17.08**	37.74	**10.76**	50.25
Total ($/boe)	**37.44**	57.21	**40.64**	51.55
Benchmark Prices				
Crude oil - WTI ($/bbl)	**57.56**	83.10	**62.42**	102.50
Crude oil - Edmonton Par ($/bbl)	**52.21**	75.37	**56.51**	94.60
Natural gas - AECO monthly index - 7A ($/Mcf)	**2.65**	4.01	**2.77**	4.42
Exchange rate - US$/CDN$	**0.75**	0.88	**0.78**	0.91

For the three months and year ended December 31, 2015, revenue decreased by 46% and 65%, respectively, compared against the same periods in 2014. The decreases were due to lower production and lower realized prices in all commodities. Lower realized prices reflected the declines in benchmark prices. The overall average realized prices did not decrease to the same extent as the individual commodity prices because of higher liquids-weighted production mix in 2015 than in 2014.

Royalties

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2015**	2014	**2015**	2014
Royalties	**746**	1,949	**2,190**	13,456
Per boe	**3.18**	6.83	**2.26**	6.22
Percentage of revenue	**8.5%**	11.9%	**5.6%**	12.1%

The majority of Lone Pine's royalties are paid to the Crown based on various sliding scales that are dependent on incentives, production volumes and commodity reference prices. Wells drilled in the Wheatland area are subject to a 17.5% flat royalty rate, which will have an impact on Lone Pine's royalty structure as the area is developed. On a percentage of revenue basis, royalties for the three months and year ended December 31, 2015 decreased from the corresponding periods in 2014 primarily as a result of significantly lower commodity prices.

Commodity Price and Risk Management

Lone Pine enters into derivative risk management contracts to manage exposure to commodity price fluctuations and to protect and provide certainty on a portion of the Company's cash flows. Lone Pine considers these derivative contracts to be an effective means to manage cash flows from operations.

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2015**	2014	**2015**	2014
Realized gains (losses) on derivatives	**4,921**	3,464	**16,785**	(6,719)
Unrealized gains (losses) on derivatives	**(730)**	25,043	**(6,843)**	20,292
Total gains on derivatives	**4,191**	28,507	**9,942**	13,573
Per boe				
Realized gains (losses) on derivatives	**20.97**	12.14	**17.34**	(3.11)
Unrealized gains (losses) on derivatives	**(3.11)**	87.78	**(7.07)**	9.38
Total gains on derivatives	**17.86**	99.92	**10.27**	6.28

As of December 31, 2015, the Company held the following outstanding derivative contracts:

Commodity Contract	**Notional Quantity**		**Remaining Term**	**Reference**	**Weighted Average Price**	**Contract Type**
Oil	750	bbls/d	January 1, 2016 – December 31, 2016	CDN$ WTI	$ 91.19	Swap
Light oil differential	1,000	bbls/d	January 1, 2016 – December 31, 2016	CDN$ MSW[6]	$ -5.35	Swap
Oil	250	bbls/d	January 1, 2016 – December 31, 2017	CDN$ WTI	$ 65.00 / 75.00	Collar
Oil	500	bbls/d	January 1, 2017 – December 31, 2017	CDN$ WTI	$ 87.78	Swap
Oil	382	bbls/d	January 1, 2017 – December 31, 2017	CDN$ WTI	$ 93.50	Call Option
Oil	500	bbls/d	January 1, 2018 – December 31, 2018	USD$ WTI	$ 65.00	Call Option

Subsequent to December 31, 2015, the Company entered into the following derivative contracts:

Commodity Contract	**Notional Quantity**		**Remaining Term**	**Reference**	**Weighted Average Price**	**Contract Type**
Natural gas	2,500	GJ/d	February 1, 2016 – December 31, 2016	AECO 7A Monthly Index	$ 2.50	Swap

[6] Settled or the monthly average Mixed Sweet Blend ("MSW") Differential to WTI.

All of the Company's derivatives contracts were entered into with counterparties that are lenders under the Lone Pine's Amended Credit Facility.

Operating Expenses

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2015**	2014	**2015**	2014
Lease operating expense	**2,943**	4,899	**12,924**	26,386
Transportation and processing	**319**	1,107	**1,147**	7,429
Production and property taxes	**472**	448	**1,888**	1,972
Total	**3,734**	6,454	**15,959**	35,787
Per boe	**15.92**	22.62	**16.49**	16.55

Lease operating expenses for the three months and year ended December 31, 2015 decreased by 40% and 51% respectively, from the same periods in 2014. The decreases were due to the Deep Basin disposition, lower production volume, improved run rates and cost reduction efforts.

For the three months and year ended December 31, 2015, transportation and processing expenses were lower than the same period in 2014 by 71% and 85% respectively. Transportation and processing activity has decreased considerably due to the Deep Basin disposition. Positive adjustments received in the current year related to the prior year production periods further contributed to the favorable variance.

Operating expenses on a per boe basis for the fourth quarter of 2015 decreased by 30% from the same period in 2014. The decrease is the result of improved run rates and cost reduction efforts. Additionally, operating expenses in the fourth quarter of 2014 were higher than the annual average as a result of increased maintenance work in the period.

Annual operating expenses on a per boe basis for 2015 were comparable to annual operating expenses for 2014. As a large portion of the Company's operating expenses are fixed costs, declining production usually results in higher per boe costs. This was not the case for 2015 as a result of the Company's cost reduction efforts.

Operating Netback

	Three Months Ended December 31,		Year Ended December 31,	
($ per boe)	**2015**	2014	**2015**	2014
Revenue	**37.44**	57.21	**40.64**	51.55
Royalties	**(3.18)**	(6.83)	**(2.26)**	(6.22)
Operating costs	**(15.92)**	(22.62)	**(16.49)**	(16.55)
Operating netback	**18.34**	27.76	**21.89**	28.78
Realized gains (losses) on derivative instruments	**20.97**	12.14	**17.34**	(3.11)
Operating netback, after realized gains (losses) on derivative instruments	**39.31**	39.90	**39.23**	25.67

Lone Pine's operating netback, after realized gains on derivative instruments, of $39.31 per boe in the fourth quarter of 2015 is comparable to the fourth quarter 2014. Decreases in realized revenue were offset by decreases in operating costs, decreases in royalties and increases in realized gains on derivative instruments.

The operating netback after realized gains on derivative instruments for the year ended December 31, 2015 increased by $13.56 per boe from the year ended December 31, 2014. The increase was primarily caused by increases in realized gains on derivative instruments from a loss of $3.11 per boe in 2014 to a gain of $17.34 per boe in 2015. The loss in 2014 was caused by the termination of natural gas hedges in the third quarter of 2014 as a result of the Deep Basin disposition, while 2015 gains were caused by the significant declines in commodity prices. This was partially offset by decreases in realized revenues by $10.91 per boe from 2014. Further contributing to the higher operating netback in 2015 was lower royalty rates.

General and Administrative Expenses

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2015**	2014	**2015**	2014
General and administrative expense	**2,638**	3,403	**13,261**	15,887
Less amounts capitalized	**(382)**	(175)	**(831)**	(4,330)
Total	**2,256**	3,228	**12,430**	11,557
Per boe	**9.62**	11.31	**12.84**	5.34

For the quarter and year ended December 31, 2015, gross G&A expenses decrease by $0.8 million and $2.6 million respectively compared to the same periods in 2014. The decreases were primarily related to reduced workforce and cost reduction initiatives.

The changes in capitalized G&A for the three months and year ended December 31, 2015, as compared to the same periods in the prior year, corresponded to the changes in the level of capital activities.

On a per boe basis, net G&A expenses in the fourth quarter of 2015 decreased by $1.69 compared to the fourth quarter of 2014. The decrease is primarily the result of the reduced workforce and cost reduction initiatives. Net G&A on a per boe basis increased by $7.50 for the 2015 annual period compared to the 2014 annual period. This increase is primarily the result of reduced production related to the Deep Basin disposition.

Finance Costs

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2015**	2014	**2015**	2014
Interest expense	**169**	316	**828**	4,863
Accretion expenses	**4,049**	3,230	**15,317**	11,700
Total finance costs	**4,218**	3,546	**16,145**	16,563
Per boe	**17.98**	12.43	**16.68**	7.66

There were no borrowings drawn on Lone Pine's available credit facilities during the three months or year ended December 31, 2015. Additionally, there were no borrowings drawn on available credit facilities during the 3 months ended December 31, 2014 as they were all repaid in the third quarter of 2014. Interest expense incurred in these periods relates to amortization of deferred financing charges, certain standby fees as well as interest on outstanding letters of credit. The decreased in interest expense in the fourth quarter of 2015 from the fourth quarter of 2014 relates to decreases in margins and reduction in borrowing capacity under the credit facility agreement when it was amended in the second quarter of 2015.

For the fourth quarter and for the year ended December 31, 2015, accretion expenses included non-cash accretion related to outstanding preferred shares in the amounts of $3.7 million and $14.0 million (2014 - $2.9 million and $10.1 million), respectively. As the preferred shares are denominated in US dollars, the weakening of the Canadian dollar throughout 2015 has resulted in higher accretion expenses.

The remaining non-cash accretion in the periods related to the decommissioning liabilities and is similar to the comparative periods.

Loss (Gain) on Foreign Exchange

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2015**	2014	**2015**	2014
Realized loss on foreign exchange	**2**	1	**—**	37
Unrealized loss on foreign exchange	**5,285**	4,213	**25,498**	5,142
Loss on foreign exchange	**5,287**	4,214	**25,498**	5,179

Foreign exchange loss relates mainly to the US dollar denominated preferred shares issued in 2014. The weakening (strengthening) of the Canadian dollar during a period would result in unrealized foreign exchange loss (gain).

Exploration and Evaluation Expense

	Three Months Ended December 31,		Year Ended December 31,	
	2015	2014	**2015**	2014
Exploration and evaluation expense	**379**	10,798	**545**	11,403
Per boe	**1.62**	37.85	**0.56**	5.27

E&E expense related mainly to expired and expiring cost of land leases.

Depletion and Depreciation

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2015**	2014	**2015**	2014
Depletion and depreciation	**3,789**	7,609	**21,436**	39,370
Per boe	**16.15**	26.67	**22.15**	18.21

Depletion and depreciation rates are subject to change based on changes in the carrying value of the asset base, reserve updates and changes in production by area. The decreases in per boe depletion and depreciation rates in the fourth quarter of 2015 from the fourth quarter of 2014 incorporates the decrease in the carrying value of the asset base due to impairment charges related to the Evi CGU of $125.5 million recognized in the fourth quarter of 2015. The increase in the 2015 annual per boe depletion and depreciation rate from the annual 2014 depletion and depreciation rate is related to the Deep Basin disposition in August 2014. The Deep Basin natural gas weighted property had a lower per unit of production depletion rate than oil and liquids weighted areas.

Impairment Loss

	Three Months Ended December 31,		Year Ended December 31,	
($000s, except per boe)	**2015**	2014	**2015**	2014
E&E Impairment	**4,868**	6,824	**8,108**	33,133
E&E Impairment – decommissioning asset	**2,410**	2,188	**2,410**	2,188
Total E&E Impairment	**7,278**	9,012	**10,518**	35,321
P&D Impairment	**—**	125,539	**912**	125,539
P&D Impairment – decommissioning asset	**270**	1,415	**1,506**	1,415
P&D Inventory	**212**	219	**212**	219
Total P&D Impairment	**482**	127,173	**2,630**	127,173
Inventory impairment	**45**	38	**150**	38
Total impairment loss	**7,804**	136,223	**13,298**	162,532

Fourth quarter and year-to-date 2015 E&E impairment losses were incurred as a result of changes in management development plans due to significant and prolonged decreases in commodity prices. Additional impairment losses were recorded related to the change in the current year's decommissioning liability estimates on certain E&E assets that were impaired in previous years.

The P&D impairment charges recognized in the fourth quarter and year-to-date 2015 primarily related to the change in the current year's decommissioning liability estimates on certain properties with no carrying value and on the write down of certain surplus inventory. Additionally, year-to-date P&D impairment charges incorporate $0.9 million related to the Hayter CGU as a result of continued declines in forward crude oil and natural gas prices.

Impairment charges could be reversed in future periods should commodity prices recover or should development plans change.

For the fourth quarter and year of 2014, the Company recognized an impairment loss of $6.8 million against unproven E&E land holdings. In addition, $2.2 million of E&E impairment loss was recognized related to increased decommissioning liabilities of certain E&E assets that had been written off in the previous year. The 2014 annual impairment also incorporated an impairment loss of $26.3 million against the Deep Basin CGU E&E assets in the second quarter of 2014, which were subsequently sold.

Upon considering annual reserves revisions and declining forward oil prices, the Company tested its CGUs for impairment at December 31, 2014. The estimated recoverable amounts were determined based on the 2014 year-end reserves evaluation. An impairment loss of $125.5 million was recognized to decrease the net book value of the Evi CGU. There was no impairment loss recorded against the Other CGU properties. The remaining $1.7 million of impairment loss recognized in 2014 was comprised of $1.4 million for current year's change in decommissioning liability estimates on properties that had zero carrying value and $0.3 million for writing down certain surplus equipment.

Capital Expenditures[7]

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2015**	2014	**2015**	2014
Drilling and completion	**7,149**	251	**10,789**	27,564
Equipment, facilities and pipelines	**1,940**	(213)	**2,944**	13,396
Wheatland land	**—**	—	**9,288**	—
Capitalized overhead, land and other	**720**	57	**1,756**	4,178
Total expenditures	**9,809**	95	**24,777**	45,138
Proceeds from disposals of property	**—**	(1,635)	**(150)**	(111,494)
Total – net	**9,809**	(1,540)	**24,627**	(66,356)

On June 30, 2015, LPR Canada entered into a lease acquisition agreement for mineral leases covering approximately 69,000 net acres of undeveloped lands in the Wheatland area in southeast Alberta ("Wheatland Acquisition"). The mineral leases have a primary term of three years, with a three-year extension option. In exchange for the leases, LPR Canada paid $9.3 million of cash consideration. Future production from these leases will be subject to a flat-rate royalty at 17.5%.

Additionally, effective December 8, 2015, Lone Pine entered into a farm-in and option agreement ("Farm-In Arrangement") to farm-in certain lands in the Wheatland area.

The Company entered into the Wheatland Acquisition and Farm-In Arrangement with the strategy to establish Wheatland as the Company's second core area. Lone Pine's 2015 four-well drilling program was conducted solely in the newly established Wheatland core area. Two wells were spudded in the third quarter, with the remaining two spudded in the fourth quarter. Completion costs for all four wells were incurred in the fourth quarter. The remaining capital expenditures were primarily incurred at Evi for electrification and well re-completions, partially offset by proceeds from the sale of surplus equipment.

Capital expenditures in 2014 were primarily invested in the Evi 11-well drilling program and Evi waterflood pilot project. Capital activity was nominal in the fourth quarter of 2014. Proceeds from dispositions of property in 2014 primarily related to the Deep Basin disposition, with additional non-core properties disposed of in the fourth quarter of 2014.

Gains on Extinguishment of Financial Liabilities

There was no gain on extinguishments of financial liabilities during the three months or year ended December 31, 2015. The net gain of $104.9 million for the year ended December 31, 2014 on extinguishment of financial liabilities was due to the followings:

- On January 31, 2014, Lone Pine emerged from Credit Protection Proceedings (as defined and discussed in the Annual Financial Statements). As a result, for the six months ended June 30, 2014, a gain of $111.1 million was recognized on the extinguishment of financial liabilities comprising Senior Notes and certain accounts payable as disclosed in the Annual Financial Statements; and

- On August 12, 2014 the Term Facility portion of the 2014 Credit facility was cancelled and a loss on the extinguishment for $6.1 million was recognized comprised of an early termination fee and accelerated amortization of deferred finance cost.

[7] Capital expenditures include expenditures on E&E assets.

Reorganization Costs

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2015**	2014	**2015**	2014
Salary and benefits – terminations	**—**	45	**1,126**	2,502
Share-based compensation	**—**	12	**176**	308
Professional fees	**94**	12	**113**	7,264
Employee retention bonus program – CCAA	**—**	—	**—**	548
Amortization and other finance costs	**—**	(5)	**—**	426
Total reorganization costs	**94**	64	**1,415**	11,048

Reorganization costs are non-recurring costs related to restructuring activities, including reduction of workforce. In 2015, the costs related mainly to staff reduction. For 2014, the expenses incurred were primarily for the Company's Creditor Protection Proceedings.

Decommissioning Liabilities

The Company's decommissioning liabilities at December 31, 2015 were $70.5 million (December 31, 2014 - $58.3 million) to provide for future remediation, abandonment and reclamation of the Lone Pine's oil and gas properties.

For the year ended December 31, 2015, the Company recognized an increase in decommissioning liabilities of $11.7 million due to changes in estimates, of which $6.8 million related to changes in discount rates. The remaining increase was primarily the result of increases in cost estimates. The changes in estimates resulted in a corresponding increase in the carrying amount of related assets, except for certain assets with a zero carrying value, in which case, the amount was immediately recognized as an impairment charge.

The undiscounted decommissioning liability is estimated to be approximately $111.8 million including $3.5 million estimated to be incurred over the next 12 months.

While the provision for decommissioning liabilities is based on management's best estimates of future costs, discount rates, timing and the economic lives of the assets, there is uncertainty regarding the amount and timing of incurring these costs.

Income Tax

At December 31, 2015, the Company had $141.2 million (December 31, 2014 – $215.5 million) of federal tax pools in Canada related to the exploration, development and production of oil and gas available for deduction against future Canadian taxable income. In addition, the Company had Canadian tax loss carry-forwards in the amount of $237.4 million (December 31, 2014 – $215.3 million), scheduled to expire in the years 2033 to 2035.

In 2015, the Canada Revenue Agency ("CRA") conducted an audit and issued a proposal letter regarding the income tax treatment of compromised debt pertaining to the CCAA, as well as certain historic tax pools. The CRA proposed $126.7 million of potential adjustments to Lone Pine's tax pools, of which the Company has reflected a decrease in the Canadian development tax pool of $57.0 million as at December 31, 2015. The Company disagrees with the CRA's position on the remaining issue and believes its position on the remaining $69.7 million of tax pools are supportable under applicable law, and as such, has not adjusted its December 31, 2015 tax pools accordingly.

As of December 31, 2015 and December 31, 2014, the Company did not recognize any deferred tax assets in the combined and consolidated statements of financial position for deductible temporary differences and unused tax losses as there was insufficient evidence to indicate that it was probable that future taxable profits in excess of profits arising from the reversal of existing temporary difference would be generated to utilize the existing deferred tax assts.

Current tax expense of $58 thousand recognized in the year ended December 31, 2015 relates to US federal income tax incurred by the Company's US entity, Lone Pine Resources.

Capital Resources and Liquidity

Capital Resources

Working Capital

At December 31, 2015, Lone Pine had working capital of $18.3 million (December 31, 2014 –$25.9 million), including $13.0 million (December 31, 2014 –$15.3 million) cash and cash equivalents on hand.

Credit Facility

At both December 31, 2015 and 2014, Lone Pine had no outstanding long-term debt. Under the Amended Credit Facility, as at December 31, 2015, $4.5 million (December 31, 2014 - $1.9 million) of letters of credit have been issued and the Company has $45.5 million (December 31, 2014 – $58.1 million) of borrowing capacity available.

On July 30, 2015, the Company renewed and amended its 2014 Credit Facility with a syndicate of banks (the "Amended Credit Facility"). Under the Amended Credit Facility, Lone Pine has a $40 million syndicated revolving term facility and a $10 million operating facility, which mature one year after the term-out date. Annually prior to the applicable term-out date, subject to the lenders' approval, Lone Pine may extend the term-out date by 364 days. The next term-out date was set at May 31, 2016; as such the maturity date of Amended Credit Facility is May 31, 2017. The Amended Credit Facility has substantially similar terms as the 2014 Credit Facility including no change to the related covenant definitions. Key changes are summarized in the 2015 Annual Financial Statements.

The Amended Credit Facility is collateralized by a demand debenture from LPR Canada and each of its restricted subsidiaries in the amount of $500 million granting a first priority security interest over all present and after-acquired personal property and a first floating charge over all other present and after-acquired property, together with a fixed charge and mortgage over its existing borrowing base assets. A fixed charge and mortgage over after-acquired borrowing base assets will only be granted under certain circumstances.

The Amended Credit Facility borrowing base is subject to a semi-annual redetermination. The next redetermination is scheduled for May 31, 2016.

As at December 31, 2015, the Company was in compliance with all covenants under the Amended Credit Facility.

Shareholders' Equity

At December 31, 2015, Lone Pine had combined common share capital of $73.9 million (December 31, 2014 – $73.9 million).

Preferred Shares

At December 31, 2015, the carrying value of preferred shares is $166.2 million (December 31, 2014 – $126.6 million), with a separate conversion liability of $26.5 million (December 31, 2015 – $26.5 million). The increase was primarily due to the translation of the US dollar denominated preferred shares at a higher US to Canadian exchange rate, coupled with accretion recognized on the preferred shares.

Capital Management and Liquidity

Lone Pine's objectives when managing capital is to maintain a flexible capital structure in order to meet its financial obligations and allow it to execute on its planned capital expenditure program. The Company considers its capital structure to include shareholders' equity, the Amended Credit Facility, preferred shares and working capital. The Company has outlined its Capital Management policy in Note 19 of the 2015 Annual Financial Statements.

Lone Pine manages its liquidity risk through its capital management of cash, debt, equity and committed credit capacity along with its planned capital expenditure program. The Company has determined that its current obligations are adequately funded by current assets. With its cash on hand, available borrowing capacity, and cash flows from operations, Line Pine believes that there is sufficient liquidity to fund its capital program and other commitments.

Contractual Obligations and Commitments

The Company has non-cancellable contractual obligations summarized as follows:

	2016	2017	2018	2019	2020	Thereafter	Total
Operating Leases – net	1,546	1,628	2,446	2,519	2,519	2,729	13,387
Firm transportation agreements	222	191	76	23	—	—	512
Other agreements	437	434	51	54	57	641	1,674
Total	2,205	2,253	2,573	2,596	2,576	3,370	15,573

Included in operating leases – net are sublease recoveries in amount of $1.8 million over the contractual period into 2018.

In addition, the Company has estimated decommissioning liabilities on its interests in wells and facilities in the total amount of $111.8 million on an undiscounted basis, of which, $17.1 million is estimated to be incurred over the next five years.

Under the Company's Equity Incentive Plan ("EIP"), the Board of Directors is authorized to grant certain equity-based awards to the Company's directors, officers and employees. Under this plan, the Company granted restricted share units ("RSUs") to its directors, officers and employees in 2014. No RSUs were granted in 2015. As at December 31, 2015 there were 271,967 outstanding RSUs granted to directors and 1,578,128 outstanding RSUs granted to officers and employees. Settlements of RSU plan awards into fully paid shares are contingent on future corporate change events and vesting conditions.

Capital Commitments

Wheatland Acquisition

Pursuant to the Wheatland Acquisition, the Company is committed to the following annual capital expenditures:

Commitment Period Ending	Capital Commitment
($000s)	
July 1, 2016	10,000
July 1, 2017	15,000
July 1, 2018	20,000

LPR Canada has the flexibility to decide the locations and the number of wells to be drilled. In the event that LPR Canada does not incur the minimum capital expenditures by the end of a given commitment period, the shortfall will be payable to the vendor. If the amount of capital expenditures incurred for any commitment period exceeds the minimal amount, such excess will be applied to satisfy capital commitment in the subsequent commitment period. During the first two years of the leases, if the average West Texas Intermediate prices for a calendar quarter are below US $50 per barrel, LPR Canada may defer a portion of the drilling commitment from that commitment period to be allocated over the remaining term.

On or before July 1, 2017, if LPR Canada fails to drill or to elect to drill one well in a specific formation on certain lands ("Specific Formation"), LPR Canada will be required to surrender the leases pertaining to the Specific Formation immediately. In the event that the Company made the election but does not drill by July 1, 2018, $250,000 will be payable to the vendor.

As at December 31, 2015, the Company has incurred $7.7 million related to the Wheatland Acquisition capital commitment.

Farm-In Arrangement

Pursuant to the Farm-In Arrangement, under which the Company may earn additional lands in the Wheatland area, a minimum of $20 million of drilling and completion expenditures must be incurred on the Farm-In Lands by December 31, 2016. Lone Pine's share of this commitment may be between 50% and 100% depending on the election to participate by the Farmor. Key terms of the Farm-In Arrangement are listed in note 22 of the 2015 Annual Financial Statements.

As at December 31, 2015, the Company has incurred $2.3 million related to the Farm-In Arrangement capital commitment.

Supplemental Information

Financial – Quarterly extracted information

($000)	2015 Q4	2015 Q3	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1
Oil and natural gas revenue	8,783	9,191	11,591	9,770	16,323	26,061	38,176	30,907
Royalties	(746)	(575)	(323)	(546)	(1,949)	(3,341)	(3,794)	(4,372)
Unrealized (loss) gain on derivatives	(730)	4,118	(6,650)	(3,581)	25,043	10,648	(1,380)	(14,019)
Realized (loss) gain on derivatives	4,921	4,421	3,063	4,380	3,464	(6,409)	(1,935)	(1,839)
Revenues	12,228	17,155	7,681	10,023	42,881	26,959	31,067	10,677
Net (loss) earnings	(15,390)	(12,985)	(9,929)	(21,590)	(127,211)	(11,334)	(22,697)	87,847

The net loss of $15.4 million in the fourth quarter of 2015 was mainly due to impairment charges of $7.3 million on E&E assets and unrealized foreign exchange losses of $5.3 million related to the translation of the US dollar denominated preferred share liability.

The net loss of $13.0 million in the third quarter of 2015 was mainly due to declining production volume and an unrealized foreign exchange loss of $10.6 million related to the translation of the US dollar denominated preferred shares liability. In addition, an impairment loss of $2.6 million was recognized including $0.9 million against the Hayter CGU and the remainder against undeveloped E&E lands.

The net loss of $9.9 million in the second quarter was mainly attributable to lower production volume and $6.6 million unrealized loss on hedge instruments. Also, there was a $1.7 million impairment charge against certain E&E lands and pre-drill cost that Lone Pine no longer intends to explore in light of low oil prices. The Company also recognized $1.3 million of reorganization costs related to workforce reduction.

The net loss of $21.6 million in the first quarter of 2015 was mainly due to lower production volume and $11.9 million unrealized loss on foreign exchange related to the translation of the US dollar denominated preferred shares liability, due to the weakening of Canadian dollar relative to the US dollar. Oil and natural gas revenue was significantly lower than the prior periods, due to lower production volume and lower realized prices across all products.

The net loss of $127.2 million in the fourth quarter of 2014 was mainly due to the recognition of $136.2 million in impairment losses. Oil and natural gas revenue decreased in the fourth quarter as a result of the Deep Basin divestiture in the third quarter of 2014 and lower liquids prices. The decreases were offset by $28.5 million of gains on oil derivatives, resulting in an overall increase of revenues in the fourth quarter, compared with the prior quarters.

The net loss of $11.3 million in the third quarter of 2014 was due to lower volumes of production as a result of the Deep Basin sale, realizing a $6.2 million loss from terminating all natural gas hedges, incurring $2.9 million of reorganization costs upon staff reduction and recognizing a $6.1 million loss on extinguishment of the Term Facility. These items were partly offset by a higher operating netback, a $10.6 million unrealized gain on derivative instruments and a $1.7 million gain on sale of property and equipment.

The net loss of $22.7 million in the second quarter of 2014 was mainly due to a $26.3 million impairment loss against Deep Basin CGU E&E assets. Oil and natural gas revenue for the second quarter of 2014 was the highest, reflecting significantly higher commodity prices.

Net earnings of $87.8 million in the first quarter of 2014 was mainly due to gain on compromised debt of $111.1 million, partially offset by $14 million of unrealized losses on derivatives and $6.9 million of reorganization costs related to the Creditor Protection Proceedings.

Critical Accounting Estimates

Lone Pine discloses Information about significant areas of estimation uncertainty and critical judgements in applying accounting policies in Note 2 to the 2015 Annual Financial Statements.

Changes in Accounting Policies

The 2015 Annual Financial Statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”). There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2015.

New or amended accounting standards and pronouncements issued that are applicable to Lone Pine in future periods are listed in Note 3 of the 2015 Annual Financial Statements. The Company is currently evaluating the impact of these standards on its financial statements.

Operational and Other Risk Factors

Lone Pine's operations are conducted in the same business environment as most other oil and gas operators and the business risks are very similar. The following summarizes the significant risks:

Risks Associated with Commodity Prices

- Lone Pine's operational results and financial condition, and therefore the amount of capital expenditures are dependent on the prices received for crude oil and natural gas production. Decreasing crude oil and natural gas prices and/or widening of oil price differentials will affect the Company's cash flow, impacting its level of capital expenditures and may result in the shut-in of certain producing properties. Longer-term adverse forward pricing outlook could also result in write-down of the Company's oil and gas assets' carrying values.

- The Amended Credit Facility has a reserves-based borrowing capacity. Decreases in future commodity prices may negatively impact the borrowing capacity and restrict Lone Pine's liquidity.

- Lone Pine may manage the risk associated with changes in commodity prices by entering into crude oil or natural gas price derivative contracts. If Lone Pine engages in activities to manage its commodity price exposure, it may forego the benefits it would otherwise experience if commodity prices were to increase. In addition, commodity derivative contracts activities could expose the Company to losses. To the extent that Lone Pine engages in risk management activities related to commodity prices, it would be subject to credit risks associated with counterparties with which it contracts.

Risks Associated with Operations

- The markets for crude oil and natural gas produced in Western Canada are dependent upon available capacity to refine crude oil and process natural gas as well as pipeline or other methods to transport the products to consumers. Pipeline capacity and natural gas liquids fractionation capacity in Alberta has not kept pace with the drilling of liquid rich gas properties in some areas of the province which may limit production periodically.

- Exploration and development activities may not yield anticipated production, and the associated cost outlay may not be recovered. In addition, the costs and expenses of drilling, completing and operating wells are often uncertain.

- Continuing production from a property are largely dependent upon the ability of the operator of the property. A significant portion of Lone Pine's production is either operated by third parties or dependent on third party's infrastructure, Lone Pine has limited ability to influence costs on partner-operated properties. To the extent the operator fails to perform their duties properly, Lone Pine's operating income from such properties may be reduced.

- The operations of oil and gas properties involves a number of operating and natural hazards which may result in health and safety incidents, environmental damage and other unexpected and/or dangerous conditions.

- Decommissioning liabilities are calculated using estimated costs and timelines based upon current operational plans, technology and reclamation practices, and environmental regulations. These factors are subject to change and such changes may impact the actual timing and amount of Lone Pine's decommissioning costs.

- The operations of oil and gas properties are subject to environmental regulation pursuant to local, provincial and federal legislation. Changes in these regulations could have a material adverse effect as regards to operating costs and capital costs. A breach of such legislation may result in the imposition of fines as well as higher operating standards that may increase costs.

- Lone Pine’s corporate EH&S program has a number of specific policies and practices to minimize the risk of safety hazards and environmental incidents. It also includes an emergency response program should an incident occur. If areas of higher risk are identified, Lone Pine will undertake to analyze and recommend changes to reduce the risk including replacement of specific infrastructure. In addition to the above, Lone Pine maintains business interruption insurance, commercial general liability insurance as well as specific environmental liability insurance, in amounts consistent with industry standards. Though Lone Pine carries industry standard property and liability insurance on its properties, losses associated with potential incidents could exceed insurance coverage limits.

Risks Associated with Reserve Estimates

- The reservoir and recovery information in reserve reports prepared by independent reserve evaluators are estimates and actual production and recovery rates may vary from the estimates and the variations may be significant. Reserves estimation process is inherently complex and subjective. The process relies on interpretations of available geological, geophysical, engineering, economic and production data. The accuracy of a reserves estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various economic assumptions and the judgement of those preparing the estimate. Because these estimates depend on many assumptions, all of which may differ from actual results, reserves estimates and estimates of future net revenue may be different from the sales volumes ultimately recovered and net revenues actually realized. Changes in market conditions, regulatory matters and the results of subsequent drilling, testing and production may require revisions to the original estimates. Estimates of reserves impact: (i) the assessment of whether or not a new well has found economically recoverable reserves; (ii) depletion rates; (iii) the determination of net recoverable amount of oil and gas properties for impairment assessment and measurement, and (iv) the determination of reserve lives which affect the timing of decommissioning activities, all of which could have a material impact on earnings, cash flows and financial positions;

Risks Associated with Capital Resources

- Absent capital reinvestment or acquisition, Lone Pine’s reserves and production levels from petroleum and natural gas properties will decline over time as a result of natural declines. As a result, cash generated from operating these properties may decline. Decreased reserves level will also negatively impact the borrowing base under outstanding credit facilities.

- Lone Pine is required to comply with covenants under the Amended Credit Facility. In the event that the Company does not comply with the covenants, its access to capital may be restricted.

- To the extent that external sources of capital become limited or unavailable or available on onerous terms, Lone Pine's ability to make capital investments, meet its capital commitments pursuant to the Wheatland Acquisition and the Farm-In Arrangement, and maintain or expand existing assets and reserves may be impaired and Lone Pine's assets, liabilities, business, financial condition, and results of operations may be materially or adversely affected as a result.

- Though Lone Pine does not have any borrowings under its Amended Credit Facility, fluctuations in interest rates could result in increase in the amount Lone Pine pays to service future debt. Changes in US/Canadian exchange rates could impact the valuation and ultimate settlement of the Preferred Shares, which are denominated in US dollars. World oil prices are quoted in US dollars and the price received by Canadian producers is therefore affected by the Canadian/US dollar exchange rate. A material increase in the value of the Canadian dollar may negatively impact Lone Pine's net production revenue.

- Although the Company monitors the credit worthiness of third parties it contracts, there can be no assurance that the Company will not experience a loss for nonperformance by any counterparty with whom it has a commercial relationship. Such events may result in material adverse consequences on the business of the Company.

General Business Risks

- The operations of Lone Pine operate under permits issued by the federal and provincial governments and these permits must be renewed periodically. The federal and provincial governments may make operating requirements more stringent, which may require additional spending.

- Provincial programs, including royalty regimes and environmental regulations, related to the oil and gas industry may change in a manner that adversely impacts the Company. Future amendments to any of these programs could result in reduced cash flow and operating results.

- The use of fracture stimulations has been ongoing safely in an environmentally responsible manner in Western Canada for decades. With the increase in the use of fracture stimulations in horizontal wells, there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology. This increased attention to fracture stimulations may result in increased regulation or changes of law, which may make the conduct of Lone Pine's business more expensive or prevent the Company from conducting its business as currently conducted.

- The operation of oil and gas properties requires physical access for people and equipment on a regular basis, which could be affected by weather, accidents, government regulations or third party actions.

- Skilled labor is necessary to run operations (both those employed directly by Lone Pine and by our contractors) and there is a risk that we may have difficulty in sourcing skilled labor which could lead to increased operating and capital costs.

- The loss of a member of our senior management team and/or key technical operations employee could result in a disruption to our operations.

- Income tax laws, other laws or government incentive programs relating to the oil and gas industry, may in the future be changed or interpreted in a manner that affects Lone Pine or its stakeholders.

Forward-Looking Statements

Certain statements and information in this MD&A may constitute forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond Lone Pine's control. All statements regarding the Company's strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. The words "could," "believe," "anticipate," "intend," "plan," "estimate," "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements with respect to, among other things:

- estimates of the Company's oil and natural gas reserves;

- estimates of the Company’s future oil, natural gas and NGL production, including estimates of any increases or decreases in the Company’s production;
- estimates of future capital expenditures;
- estimates and judgements related to common shares and preferred shares valuations;
- the Company’s future financial condition and results of operations;
- the Company’s ability to meet its capital commitment pursuant to the Wheatland Acquisition and the Farm-In Arrangement;
- the Company’s future revenues, cash flows and expenses;
- the Company’s access to capital and expectations with respect to liquidity and capital resources;
- the Company’s future business strategy and other plans and objectives for future operations;
- the Company’s future development opportunities and production mix;
- the Company’s outlook on oil, natural gas and NGL prices;
- the amount, nature and timing of future capital expenditures, including future development costs;
- the Company’s ability to access the capital markets to fund capital and other expenditures;
- the Company’s assessment of the Company’s counterparty risk and the ability of the Company’s counterparties to perform their future obligations; and
- the impact of federal, provincial, territorial and local political, legislative, regulatory and environmental developments in Canada.

Lone Pine believes the expectations and forecasts reflected in the Company’s forward-looking statements are reasonable, but Lone Pine can give no assurance that they will prove to be correct. Readers are cautioned that these forward-looking statements can be affected by inaccurate assumptions and are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond the Company’s control, incident to the exploration for and development, production and sale of oil and natural gas. When considering forward-looking statements, you should keep in mind the assumptions, risk factors and other cautionary statements that include, among other things:

- the volatility of oil, natural gas and NGL prices, and the related differentials between realized prices and benchmark prices;
- a continuation of depressed crude oil and natural gas prices;
- the availability of capital on economic terms to fund the Company’s significant capital expenditures and acquisitions;
- the Company’s ability to obtain adequate financing to pursue other business opportunities;
- the Company’s ability to generate sufficient cash flow from operations or obtain adequate financing to fund the Company’s capital expenditures and meet working capital needs;
- the Company’s ability to replace and sustain production;
- a lack of available drilling and production equipment, and related services and labor;
- increases in costs of drilling, completion and production equipment and related services and labor;
- unsuccessful exploration and development drilling activities;
- regulatory and environmental risks associated with exploration, drilling and production activities;
- declines in the value of the Company’s oil and natural gas properties, resulting in impairments;
- the adverse effects of changes in applicable tax, environmental and other regulatory legislation;
- a deterioration in the demand for the Company’s products;
- the risks and uncertainties inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and the timing of expenditures;
- the risks of conducting exploratory drilling operations in new or emerging plays;
- intense competition with companies with greater access to capital and staffing resources;
- the risks of conducting operations in Canada and the impact of pricing differentials, fluctuations in foreign currency exchange rates and political developments on the financial results of the Company’s operations; and
- the uncertainty related to the pending litigation against us.

Should one or more of the risks or uncertainties described above or elsewhere in this MD&A occur, or should underlying assumptions prove incorrect, Lone Pine's actual results and plans could differ materially from those expressed in any forward-looking statements. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date of this MD&A, and Lone Pine undertakes no obligation to update this information to reflect events or circumstances after the delivery of this MD&A. All forward-looking statements, expressed or implied, included in this MD&A are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that Lone Pine may make or persons acting on the Company's behalf may issue.

Other Advisories

Volumetric Conversion

The oil and gas industry commonly expresses production volumes and reserves on a "barrel of oil equivalent" basis ("boe") whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants.

Throughout the MD&A, Lone Pine has used the 6:1 boe measure, which is the approximate energy equivalency of the two commodities at the burner tip. Boe does not represent a value equivalency at the wellhead nor at the plant gate, which is where Lone Pine sells its production volumes and therefore may be a misleading measure, particularly if used in isolation. Given that the value ration based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion may be misleading as an indication of value.

Non-IFRS Measures

Lone Pine uses terms within the MD&A that do not have a standardized prescribed meaning under IFRS and these measurements may not be comparable with the calculation of similar measurements used by other companies. The non-IFRS measures used in this report are summarized as follows:

Operating Netback

Operating netback is a non-IFRS measure commonly used in the oil and gas industry. This measurement assists management and investors to evaluate the specific operating performance at the oil and gas lease level. Operating netbacks included in this report were determined by taking (oil and gas revenues less royalties less operating costs) divided by gross working interest production. Operating netback, including realized commodity (loss) and gain, adjusts the operating netback for only realized gains and losses on derivative instruments.

EBITDAX

The Company monitors its capital structure based on the ratio of total debt to EBITDAX. The ratio provides a measure of the Company's ability to manage its debt levels under current operating conditions. "Total debt" and "EBITDAX" are terms corresponding to defined terms in the Amended Credit Facility agreement for the purpose of calculation of our financial covenants. The Company also uses EBITDAX as a measure of its operating cash flows.

EBITDAX means net earnings before financing charges, foreign exchange gain (loss), E&E expense, income taxes, depreciation, depletion, amortization, other non-cash items of expense and non-recurring items. The following is a reconciliation of EBITDAX to the nearest IFRS measure, net earnings (loss) before income tax:

	Three Months Ended December 31,		Year Ended December 31,	
($000s)	**2015**	2014	**2015**	2014
Net loss before income tax	**(15,332)**	(127,211)	**(59,836)**	(73,395)
Add (deduct):				
Finance costs	**4,218**	3,546	**16,145**	16,563
Loss on foreign exchange	**5,287**	4,214	**25,498**	5,179
Reorganization costs[8]	**94**	64	**1,415**	11,048
Share-based compensation – net	**169**	960	**1,041**	1,831
Loss (gain) on sale of properties	**—**	(2,036)	**197**	(3,512)
Gain on extinguishment of financial liabilities - net	**—**	—	**—**	(104,948)
Exploration and evaluation expense	**379**	10,789	**545**	11,403
Depletion and depreciation	**3,789**	7,609	**21,436**	39,370
Impairment loss on exploration and evaluation assets	**7,804**	136,223	**13,298**	162,532
Unrealized (gain) loss on derivative instruments	**730**	(25,043)	**6,843**	(20,292)
EBITDAX	**7,138**	9,115	**26,582**	45,779

For purposes of calculating covenants under the Amended Credit Facility, EBITDAX (hereinafter referred to as "Adjusted EBITDAX") is determined using financial information from the most recent four consecutive fiscal quarters. Adjusted EBITDAX also includes adjustments for major acquisitions and material dispositions assuming that such transactions had occurred on the first day of the applicable calculation period.

[8] Reorganization cost includes share-based compensation related to terminations.