LONG RUN EXPLORATION LTD.

Management's Discussion and Analysis

September 30, 2015

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For the three and nine months ended September 30, 2015

This Management's Discussion & Analysis ("MD&A") of the financial condition and results of operations of Long Run Exploration Ltd. ("Long Run", the "Company", "its" or "our") should be read in conjunction with the unaudited interim financial statements for the period ended September 30, 2015 and the audited financial statements and MD&A for the year ended December 31, 2014. The disclosure which is unchanged from the MD&A for the year ended December 31, 2014 may not be repeated herein.

The Company follows International Financial Reporting Standards ("IFRS"). Amounts shown in the MD&A are in Canadian dollars unless otherwise stated. All production volumes disclosed herein are sales volumes. Certain prior year amounts have been reclassified to reflect the current year classification of capital expenditures and production volumes by area.

The MD&A contains certain measures that do not have any standardized meaning as prescribed by IFRS and therefore are considered non-Generally Accepted Accounting Principles ("Non-GAAP") measures. Readers are cautioned that the MD&A should be read in conjunction with the disclosure in the Non-GAAP Measures and the Advisory sections located at the end of this document. The Advisory provides information on forward-looking statements and oil and natural gas information.

See the Abbreviations section at the end of this document for abbreviations used throughout.

This document is dated November 16, 2015.

Long Run's Strategy

Long Run Exploration Ltd. is an intermediate oil and natural gas company focused on development, exploration and production in the Western Canadian Sedimentary Basin. We complement our development programs with strategic acquisitions and dispositions. Targeting a production mix balanced between oil and natural gas, activities are concentrated in our core areas, which include the Peace River Montney, the Deep Basin Cardium, the Redwater Viking and the Boyer Bluesky.

Long Run has assembled a large land position and is continuing to add oil and natural gas infrastructure in our key areas, providing flexibility for future growth and development. Through controlled exploitation, enhanced recovery and selective low risk exploration, Long Run strives to maximize operating and cost efficiencies.

Long Run continues to examine strategic and financial means to improve the capital structure of the Company. As an initial step in this process, Long Run entered into an amended and restated private placement agreement ("the Private Placement") with Maple Marathon Investments Limited ("Maple Marathon") and MIE Holdings Corporation ("MIE") on November 8, 2015. Under the proposed Private Placement, Long Run expects to receive gross proceeds of $100 million in January 2016, which will be used for debt reduction.

In conjunction with the proposed Private Placement, Long Run is proceeding with strategic asset rationalization to improve its capital structure. The Board and management team of Long Run have initiated a formal asset disposition process of both core and non-core assets from the Company's diversified asset base to address the Company's non-revolving syndicated facility which is due by May 29, 2016.

For 2015, Long Run expects funds flow from operations of $135 - $140 million to exceed net capital expenditures of $70 million and intends to use part of this excess to repay a portion of our non-revolving syndicated facility. On closing of the proposed Private Placement, the proceeds of $100 million will be used to further reduce indebtedness under the non-revolving syndicated facility. The remaining balance on the non-revolving syndicated facility is planned to be repaid through asset dispositions. The Company remains on track to meet our 2015 production guidance of 32,000 - 33,000 Boe/d.

Highlights

Third quarter 2015 compared to third quarter 2014

- Generated funds flow from operations of $35.5 million ($0.18/share) compared to $80.2 million ($0.45/share) in 2014, primarily reflecting lower commodity prices and lower oil production, partially offset by a gain on financial derivatives, lower royalties and lower operating costs.

- Completed a targeted 12.0 net well drilling program focused on the Redwater Viking property. Total capital expenditures in the third quarter of $19.4 million compared to $75.8 million in 2014, reflecting our controlled capital program in response to the depressed commodity price environment. In 2014, capital spending focused on the Peace River Montney, Deep Basin Cardium, and Redwater Viking areas.

- Executed on $19.2 million in non-core dispositions with proceeds directed towards debt repayment.

- Reduced net debt over the quarter by $30.5 million to $678.8 million, primarily as a result of disposition proceeds and funds flow from operations exceeding capital expenditures.

- Averaged 30,733 Boe/d of production compared to 34,795 Boe/d in 2014, including the impact of the Alliance pipeline outage and the shut-in of high operating cost wells for approximately 700 Boe/d. The decrease in production reflects our reduced capital spending in Peace River and Redwater, partially offset by the production increase attributable to the Deep Basin properties acquired in August 2014 and our successful drilling program in this new area.

- Oil prices including derivatives averaged $68.27/Bbl compared to $84.66/Bbl in 2014 as a result of a decrease in the West Texas Intermediate benchmark pricing, partially offset by an increase in the U.S. dollar exchange rate and a realized gain on oil financial derivatives.

  Average NGLs pricing for the quarter decreased to $20.74/Bbl from $57.98/Bbl in 2014, reflecting lower market prices as well as the change in our NGLs product mix due to the Deep Basin properties acquired in August 2014.

  Natural gas prices including derivatives averaged $3.34/Mcf compared to $4.23/Mcf in 2014, primarily attributable to weaker AECO benchmark prices partially offset by a realized gain on natural gas financial derivatives.

- Reported a net loss of $305.1 million compared to net earnings of $40.6 million in 2014. The loss was primarily a result of non-cash impairment charges of $285.0 million attributable to the decline in future commodity price forecasts as at September 30, 2015.

- Entered into a private placement agreement with Maple Marathon Investment Limited (“Maple Marathon”) and MIE Holdings Corporation (“MIE”), which is described further below.

Nine months ended September 30, 2015 compared to nine months ended September 30, 2014

- Reduced net debt by $60.8 million in accordance with our goal of debt reduction. The net debt reduction resulted from disposition proceeds and funds flow from operations exceeding capital expenditures.

- Generated funds flow from operations of $121.4 million ($0.62/share diluted) compared to $223.7 million ($1.53/share diluted) in 2014, primarily reflecting lower commodity prices, lower oil production and higher interest costs, partially offset by higher natural gas and NGLs production, a gain on financial derivatives, lower royalties, lower general and administration expense and lower operating costs.

- Executed a focused development program, drilling 21.0 net wells. Capital expenditures of $73.5 million compared to $233.9 million in 2014. Capital spending in 2015 was concentrated on our Peace River Montney, Deep Basin Cardium and Redwater Viking core areas. In 2014, capital spending was focused on the Peace River Montney and Redwater Viking areas.

- Successfully executed on $31.3 million in non-core dispositions with proceeds directed towards debt repayment.

- Averaged 33,579 Boe/d of production, an increase of 4,209 Boe/d from 29,370 Boe/d in 2014. The production increase primarily resulted from the liquids-rich natural gas weighted Deep Basin acquisitions in 2014 and our successful drilling program in this new area. The increase was partially offset by our reduced capital spending in Peace River and Redwater and the impact of the Alliance pipeline outage and the shut-in of high operating cost wells.

- Oil prices including derivatives decreased to $68.44/Bbl from $86.67/Bbl in 2014. The decrease in the West Texas Intermediate benchmark pricing was partially offset by a realized gain on oil financial derivatives and an increase in the U.S. dollar exchange rate.

  Average NGLs pricing decreased to $22.61/Bbl from $69.28/Bbl in 2014, reflecting lower market prices as well as the change in our NGLs product mix due to the Deep Basin acquisitions in 2014.

  Natural gas prices including derivatives decreased to $3.27/Mcf from $4.68/Mcf in 2014, primarily attributable to weaker AECO benchmark prices, partially offset by a realized gain on natural gas financial derivatives.

- Recorded a net loss of $378.0 million compared to net earnings of $68.3 million in 2014. The loss was primarily a result of non-cash impairment charges attributable to reduced future commodity price forecasts as at September 30, 2015, lower funds flow from operations and an unrealized loss on financial derivatives.

- On August 2, 2015, the Company entered into a private placement agreement with Maple Marathon and MIE. On November 8, 2015, Long Run entered into an amended and restated agreement, pursuant to which Long Run will issue to Maple Marathon, by way of Private Placement, 125,000,000 units ("Units") at an issue price of $0.80 per Unit for gross proceeds of $100 million.

  Each Unit will be comprised of one common share of Long Run and 0.728 of a common share purchase warrant (the "Warrants"). Each Warrant will entitle the holder to acquire one common share of Long Run at an exercise price of $1.10 for a period of 12 months from closing of the Private Placement, for additional proceeds of approximately $100 million to Long Run, if exercised in full. The closing of the Private Placement is subject to various conditions including obtaining shareholder and regulatory approvals.

Quarterly Results Overview

($000s, except per share or unless otherwise noted)	Nine months ended September 30 2015	Nine months ended September 30 2014	2015 Q3	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1
Funds flow from operations [1]	**121,359**	223,678	**35,477**	45,924	39,958	68,178	80,199	73,429	70,050
Per share, basic [1]	**0.63**	1.54	**0.18**	0.24	0.21	0.35	0.45	0.55	0.56
Per share, diluted [1]	**0.62**	1.53	**0.18**	0.24	0.21	0.35	0.45	0.54	0.56
Net earnings (loss)	**(378,012)**	68,257	**(305,058)**	(50,136)	(22,818)	(258,652)	40,644	20,842	6,771
Per share, basic	**(1.95)**	0.47	**(1.58)**	(0.26)	(0.12)	(1.34)	0.23	0.16	0.05
Per share, diluted	**(1.95)**	0.47	**(1.58)**	(0.26)	(0.12)	(1.34)	0.23	0.15	0.05
Revenues, before royalties	**247,031**	477,542	**72,271**	93,436	81,324	133,354	166,978	158,678	151,886
Capital expenditures	**73,452**	233,938	**19,367**	8,770	45,315	70,094	75,759	57,330	100,848
Net divestitures [2]	**(28,836)**	(26,878)	**(17,914)**	(9,530)	(1,392)	(1,797)	(8,147)	(15,051)	(3,679)
Net capital expenditures [2]	**44,616**	207,060	**1,453**	(760)	43,923	68,297	67,612	42,279	97,169
Production									
Oil *(Bbl/d)*	**9,316**	12,745	**7,990**	9,429	10,557	12,130	13,071	12,476	12,684
Natural gas liquids *(Bbl/d)*	**4,711**	2,223	**4,277**	4,659	5,210	5,609	3,031	2,038	1,584
Total Liquids *(Bbl/d)*	**14,027**	14,968	**12,267**	14,088	15,767	17,739	16,102	14,514	14,268
Natural gas *(Mcf/d)*	**117,311**	86,414	**110,799**	122,214	119,007	112,576	112,161	78,524	68,071
Total *(Boe/d)*	**33,579**	29,370	**30,733**	34,457	35,602	36,502	34,795	27,602	25,613
Prices, including derivatives									
Oil *($/Bbl)*	**68.44**	86.67	**68.27**	72.03	65.34	79.35	84.66	89.59	85.89
Natural gas liquids *($/Bbl)*	**22.61**	69.28	**20.74**	24.48	22.50	30.02	57.98	72.76	86.87
Total Liquids *($/Bbl)*	**53.05**	84.09	**51.69**	56.31	51.18	63.75	79.64	87.23	85.99
Natural gas *($/Mcf)*	**3.27**	4.68	**3.34**	3.30	3.17	4.15	4.23	4.61	5.53
Total *($/Boe)*	**33.80**	56.80	**32.81**	35.04	33.45	43.92	50.75	59.13	62.67
Operating netback *($/Boe)*	**18.45**	34.03	**18.55**	19.92	16.94	25.04	31.41	35.04	36.55

[1] See Non-GAAP Measures section
[2] Excludes $228.8 million paid for the Deep Basin acquisition on May 30, 2014

Significant Properties

Long Run's key development areas within our property portfolio include the Peace River Montney, the Deep Basin and the Redwater Viking. The Peace River Montney is focused on Montney light oil development at Normandville and Girouxville. The Deep Basin property was acquired by Long Run through two strategic acquisitions completed in May and August 2014. The Deep Basin area, including the Edson and Kakwa/Elmworth properties, is focused on light oil and liquids rich natural gas development from the Cardium and Bluesky formations. The Redwater Viking property, located near Edmonton, Alberta, is focused on light oil development from the Viking formation. The Company also owns a significant low decline shallow gas property at Boyer in northern Alberta.

During the third quarter of 2015, Long Run invested $0.5 million into the Peace River Montney area, drilling no new wells. Third quarter 2015 production averaged 7,497 Boe/d, consisting of 4,051 Bbl/d of oil and NGLs and 20,678 MMcf/d of natural gas. In the first nine months of 2015, Long Run invested $18.2 million which included the drilling of 5.0 net Montney wells with a 100% success rate, resulting in average production of 8,589 Boe/d (55% oil and NGLs). Capital expenditures for 2015 are expected to total approximately $20 million in this area. No further wells are planned for the remainder of 2015. The Company operates, transports, and processes all of its production within the Peace River area.

Long Run invested $2.2 million in the Deep Basin - Edson area in the third quarter of 2015, drilling no new wells. Third quarter 2015 production averaged 6,430 Boe/d, consisting of 2,562 Bbl/d of oil and NGLs and 23,207 Mcf/d of natural gas. In the first nine months of 2015, Long Run invested $18.9 million which included the drilling of 3.0 net wells with a 100% success rate, resulting in average production of 7,096 Boe/d (42% oil and NGLs). Capital expenditures for 2015 are expected to total approximately $21 million in this area, with additional investments in facility optimizations planned for the fourth quarter. No further wells are planned for the remainder of 2015.

In the Deep Basin - Kakwa/Elmworth area, Long Run invested $0.5 million in the third quarter of 2015, with no new wells drilled. Third quarter 2015 production averaged 4,854 Boe/d, consisting of 948 Bbl/d of oil and NGLs and 23,436 Mcf/d of natural gas. In the first nine months of 2015, Long Run invested $13.0 million which included the drilling of 1.0 net well with a 100% success rate, resulting in average production of 5,167 Boe/d (21% oil and NGLs) as well as investing in plant and battery equipment. Capital expenditures for 2015 are expected to total approximately $21 million in this area including the drilling of 2.0 net wells in the fourth quarter.

In the Redwater Viking area, Long Run invested $11.0 million in the third quarter of 2015, drilling 12.0 net wells. Third quarter production averaged 2,942 Boe/d, consisting of 2,547 Bbl/d of oil and NGLs and 2,371 Mcf/d of natural gas. In the first nine months of 2015, Long Run invested $14.4 million which included the drilling of 12.0 net wells, with a 100% success rate, with production averaging 3,326 Boe/d (87% oil and NGLs). Capital expenditures for 2015 are expected to total approximately $17 million in this area. No further wells are planned for the remainder of 2015. The Company operates, transports, and processes substantially all of its production within the Redwater area.

For the fourth quarter of 2015, Long Run has reallocated its development capital based on current anticipated cost structures and forecast commodity prices. The Company is planning to drill 2.0 Kakwa Cardium wells in place of the previously forecast 3.0 Edson Cardium wells in the quarter. This reallocation is reflected in the 2015 planned capital spending described above.

Capital Investment

Capital Expenditures, Acquisitions & Dispositions

($000s)	Q3 2015	Q3 2014	Nine months ended September 30 2015	Nine months ended September 30 2014
Drilling and completion	**13,434**	52,530	**49,495**	162,495
Plant and facilities	**4,487**	19,740	**18,656**	59,551
Geological and geophysical	**14**	1,951	**834**	7,185
Other assets	**1,432**	1,538	**4,467**	4,707
Capital expenditures	**19,367**	75,759	**73,452**	233,938
Acquisitions – land	**1,144**	1,071	**1,733**	5,765
– properties	**133**	7,423	**691**	241,101
Dispositions	**(19,191)**	(16,641)	**(31,260)**	(44,977)
Net capital expenditures	**1,453**	67,612	**44,616**	435,827

Drilling Activity

		Q3 2015 Wells		Q3 2014 Wells		Success Rate *(net wells)*	
		Gross	Net	Gross	Net	Q3 2015	Q3 2014
Peace River	– Montney	-	-	12.0	12.0	-	100%
	– Other	-	-	-	-	-	-
Deep Basin	– Edson	-	-	3.0	3.0	-	100%
	– Kakwa/Elmworth	-	-	-	-	-	-
Redwater	– Viking	**12.0**	**12.0**	6.0	6.0	**100%**	100%
	– Other	-	-	-	-	-	-
Other		-	-	-	-	-	-
		12.0	**12.0**	21.0	21.0	**100%**	100%

		Nine months ended September 30					
		2015 Wells		2014 Wells		Success Rate *(net wells)*	
		Gross	Net	Gross	Net	2015	2014
Peace River	– Montney	**5.0**	**5.0**	41.0	40.5	**100%**	100%
	– Other	-	-	2.0	2.0	-	100%
Deep Basin	– Edson	**3.0**	**3.0**	3.0	3.0	**100%**	100%
	– Kakwa/Elmworth	**1.0**	**1.0**	-	-	**100%**	-
Redwater	– Viking	**12.0**	**12.0**	43.0	43.0	**100%**	100%
	– Other	-	-	2.0	1.0	-	100%
Other		-	-	1.0	1.0	-	100%
		21.0	**21.0**	92.0	90.5	**100%**	100%

Capital Expenditures

Capital expenditures in the third quarter of 2015 were $19.4 million, including $0.5 million (3%) in the Peace River Montney, $2.2 million (11%) in the Deep Basin at Edson, $0.5 million (3%) in the Deep Basin at Kakwa/Elmworth and $11.0 million (57%) in the Redwater Viking. The Company drilled 12.0 (12.0 net) wells focused on the Redwater Viking property with a 100% success rate in the period.

Capital expenditures in the third quarter of 2014 were $75.8 million, including $38.3 million (51%) in the Peace River Montney, $12.3 million (16%) in the Deep Basin at Edson and $17.3 million (23%) in the Redwater Viking. The Company drilled 21.0 (21.0 net) wells with a 100% success rate in the period.

Capital expenditures in the first nine months of 2015 were $73.5 million, including $18.2 million (25%) in the Peace River Montney, $18.9 million (26%) in the Deep Basin at Edson, $13.0 million (18%) in the Deep Basin at Kakwa/Elmworth and $14.4 million (20%) in the Redwater Viking. The Company drilled 21.0 (21.0 net) wells with a 100% success rate for the nine months ended September 30, 2015.

Capital expenditures in the first nine months of 2014 were $233.9 million, including $121.4 million (52%) in the Peace River Montney, $12.3 million (5%) in the Deep Basin at Edson and $65.3 million (28%) in the Redwater Viking. The Company drilled 92.0 (90.5 net) wells with a 100% success rate for the nine months ended September 30, 2014.

Acquisitions and Dispositions

Net disposition proceeds of $17.9 million were received in the third quarter of 2015 and $28.8 million were received in the first nine months of 2015. Third quarter disposition proceeds of $19.2 million were received in the third quarter of 2015 relating to the disposition of a minor non-core property in the Redwater area producing approximately 600 Boe/d. Proceeds from the dispositions have been directed towards debt repayment. Disposition proceeds for the first nine months of 2015 were $31.3 million, relating to the disposition of a minor non-core property in the third quarter of 2015, and the disposition of a pipeline and minor properties producing approximately 50 Boe/d in the second quarter of 2015.

Net disposition proceeds in the third quarter of 2014 were $8.1 million and net acquisitions for the first nine months of 2014 were $201.9 million. Disposition proceeds received in the third quarter of 2014 of $16.6 million related primarily to a property disposition in Pine Creek. Acquisitions in the third quarter of 2014 were $8.5 million, consisting primarily of a minor property tuck-in in Redwater. Net acquisitions for the first nine months of 2014 primarily related to the Deep Basin asset acquisition, which closed on May 30, 2014. The acquisition included development and exploration assets located primarily in the Kakwa/Elmworth and Edson areas.

Enhanced Oil Recovery

Enhanced oil recovery (“EOR”) remains a key part of the Company’s strategic development plans. Long Run’s first EOR project is in our Peace River Montney area where the Company has two active EOR expansion projects. The EOR project at Normandville covers 5 sections (16 horizontal producers, 8 horizontal injection wells, 1 vertical injection well) and became operational in December 2014. A similar EOR project began in January 2015 at Girouxville covering 1.5 sections (6 horizontal producers, 4 horizontal injection wells). Operations at both waterflood projects are advancing according to our reservoir models, with signs of reservoir response beginning to show in both areas over recent months. This response has come in the form of stabilizing and increasing fluid and oil rates, as well as a downward trend in gas-oil ratio’s, in certain areas within the projects.

Successful EOR implementation in the Montney area has the potential to substantially improve recoveries, reduce production declines and improve capital efficiencies. Full field implementation of EOR at Normandville and Girouxville could ultimately cover approximately 30 net sections.

Redwater remains an active area for Long Run as the site of our second major EOR project. Long Run initiated the first Viking EOR project in the north part of the field in December 2013. A second complementary EOR project, located in the south part of the trend, began injection in early December 2014. Together these projects cover an area of 1.125 sections and include 11 horizontal Viking producers, 6 vertical Viking producers, and 5 horizontal injection wells.

Production

Average Production by Product

			Nine months ended September 30	
	Q3 2015	Q3 2014	**2015**	2014
Liquids *(Bbl/d)*				
Light oil	**7,711**	12,708	**8,995**	12,007
Heavy oil	**279**	363	**321**	738
NGLs	**4,277**	3,031	**4,711**	2,223
Total	**12,267**	16,102	**14,027**	14,968
Natural Gas *(Mcf/d)*	**110,799**	112,161	**117,311**	86,414
Total *(Boe/d)*	**30,733**	34,795	**33,579**	29,370

Average Production by Area

		Q3 2015				Q3 2014			
		Oil *(Bbl/d)*	**NGLs** *(Bbl/d)*	**Natural Gas** *(Mcf/d)*	**Total** *(Boe/d)*	Oil *(Bbl/d)*	NGLs *(Bbl/d)*	Natural Gas *(Mcf/d)*	Total *(Boe/d)*
Peace River	– Montney	**3,788**	**263**	**20,678**	**7,497**	6,400	298	25,326	10,919
	– Other	**690**	**97**	**7,554**	**2,046**	956	128	11,817	3,053
Deep Basin	– Edson	**459**	**2,103**	**23,207**	**6,430**	527	805	19,932	4,654
	– Kakwa/Elmworth	**69**	**879**	**23,436**	**4,854**	37	851	13,913	3,207
Redwater	– Viking	**2,494**	**53**	**2,371**	**2,942**	4,356	89	4,060	5,122
	– Other	**490**	**82**	**13,984**	**2,903**	795	92	13,856	3,196
Boyer		**-**	**-**	**16,303**	**2,717**	-	1	17,569	2,929
Other		**-**	**800**	**3,266**	**1,344**	-	767	5,688	1,715
		7,990	**4,277**	**110,799**	**30,733**	13,071	3,031	112,161	34,795

		Nine months ended September 30, 2015				Nine months ended September 30, 2014			
		Oil *(Bbl/d)*	**NGLs** *(Bbl/d)*	**Natural Gas** *(Mcf/d)*	**Total** *(Boe/d)*	Oil *(Bbl/d)*	NGLs *(Bbl/d)*	Natural Gas *(Mcf/d)*	Total *(Boe/d)*
Peace River	– Montney	**4,479**	**275**	**23,012**	**8,589**	5,793	237	22,965	9,857
	– Other	**755**	**110**	**8,527**	**2,286**	1,055	142	12,390	3,262
Deep Basin	– Edson	**593**	**2,363**	**24,840**	**7,096**	190	289	7,249	1,687
	– Kakwa/Elmworth	**59**	**1,006**	**24,611**	**5,167**	34	407	6,705	1,558
Redwater	– Viking	**2,839**	**48**	**2,634**	**3,326**	4,617	67	4,099	5,367
	– Other	**589**	**95**	**14,497**	**3,100**	1,056	156	10,282	2,926
Boyer		**2**	**1**	**15,784**	**2,634**	-	1	17,415	2,904
Other		**-**	**813**	**3,406**	**1,381**	-	924	5,309	1,809
		9,316	**4,711**	**117,311**	**33,579**	12,745	2,223	86,414	29,370

During the third quarter of 2015, production averaged 30,733 Boe/d, compared to 34,795 Boe/d in 2014 including the impact of the Alliance pipeline outage in August and the shut-in of high operating cost wells for approximately 700 boe/d. The decrease in production reflects our reduced capital spending in the Peace River and Redwater areas, partially offset by the production increase from the Deep Basin properties acquired in August 2014 and our successful drilling program in this new area.

Production for the first nine months of 2015 averaged 33,579 Boe/d from 29,370 Boe/d in 2014, including the reduction of approximately 300 Boe/d due to outages, non-core dispositions and the shut-in of high operating cost wells. The production increase resulted primarily from the Deep Basin acquisitions in 2014 partially offset by reduced capital spending in 2015.

Peace River Montney production averaged 7,497 Boe/d in the third quarter of 2015, compared to 10,919 Boe/d in 2014. Over the first nine months of 2015, production averaged 8,589 Boe/d compared to 9,857 Boe/d in 2014. The lower production volumes were primarily a result of reduced capital spending in the area in 2015. Long Run invested $18.2 million in the Peace River Montney over the first nine months of 2015 compared to $121.4 million in 2014.

Deep Basin production averaged 11,284 Boe/d in the third quarter of 2015 compared to 7,861 Boe/d in 2014. The production increase from the Deep Basin properties acquired in August 2014 was partially offset by an operational event on the Alliance Pipeline system which required suppliers to suspend natural gas injections into the pipeline for six days during August 2015. The outage resulted in the deferral of approximately 21.5 MMcf/d of natural gas production and approximately 2,500 Bbls/d of oil and NGLs in our Deep Basin Edson area over the six days. This downtime reduced third quarter production by approximately 400 Boe/d. Over the first nine months of 2015, production averaged 12,263 Boe/d compared to 3,245 Boe/d in 2014. The production increase resulted primarily from the Deep Basin acquisitions in 2014 and our successful drilling program in the area.

Redwater Viking production for the third quarter of 2015 averaged 2,942 Boe/d compared to 5,122 Boe/d in 2014. Production averaged 3,326 Boe/d over the first nine months of 2015 compared to 5,367 Boe/d in 2014. The lower production volumes were primarily a result of reduced capital spending in the area in 2015 as compared to 2014. Long Run invested $14.4 million in the Redwater Viking over the first nine months of 2015 compared to $65.3 million in 2014.

Commodity Pricing

	Q3 2015	Q3 2014	Nine months ended September 30 2015	2014
Benchmark pricing				
WTI *(US$/Bbl)*	**46.44**	97.21	**50.98**	99.60
Edmonton Light Sweet *(CDN$/Bbl)*	**56.27**	97.18	**58.63**	100.80
AECO *($/Mcf)*	**2.84**	4.02	**2.75**	4.78
US$/CDN$ exchange rate	**1.31**	1.09	**1.26**	1.09
Prices, excluding derivatives				
Liquids *($/Bbl)*				
Light oil	**45.78**	88.08	**48.76**	92.16
Heavy oil	**40.59**	81.47	**44.44**	80.20
Total Oil	**45.59**	87.90	**48.61**	91.47
NGLs	**20.74**	57.98	**22.61**	69.28
Total	**36.93**	82.26	**39.88**	88.18
Natural Gas *($/Mcf)*	**2.95**	4.29	**2.88**	4.91
Total *($/Boe)*	**25.56**	52.16	**26.95**	59.56
Prices, including derivatives				
Liquids *($/Bbl)*				
Oil	**68.27**	84.66	**68.44**	86.67
NGLs	**20.74**	57.98	**22.61**	69.28
Total	**51.69**	79.64	**53.05**	84.09
Natural Gas *($/Mcf)*	**3.34**	4.23	**3.27**	4.68
Total *($/Boe)*	**32.81**	50.75	**33.80**	56.80

The Company's financial results are influenced by fluctuations in commodity prices, exchange rates and Canadian price differentials. Long Run's average oil price excluding derivatives for the third quarter of 2015 was $45.59/Bbl, a decrease of $42.31/Bbl from 2014. Our average oil price excluding derivatives during the first nine months of 2015 was $48.61/Bbl, a decrease of $42.86/Bbl over 2014. The decreases resulted from lower West Texas Intermediate benchmark pricing, partially offset by an increase in the U.S dollar exchange rate.

Long Run's NGLs price in the third quarter of 2015 was $20.74/Bbl, a decrease of $37.24/Bbl over 2014. Our average NGLs price during the first nine months of 2015 was $22.61/Bbl, a decrease of $46.67/Bbl over 2014. The decreases were a result of lower market prices as well as the change in our NGLs product mix due to the Deep Basin acquisitions in 2014.

In the third quarter of 2015, the Company's natural gas price excluding derivatives was $2.95/Mcf, a decrease of $1.34/Mcf over 2014. Our average natural gas price during the first nine months of 2015 was $2.88/Mcf, a decrease of $2.03/Mcf from 2014. The decreases were primarily due to the weakening of AECO benchmark pricing. The Company's natural gas price reflects premiums received for the liquids content included in the natural gas production.

The Company enters into financial derivative contracts for the purpose of protecting funds flow from operations due to the volatility of commodity prices. During the third quarter of 2015, our oil price of $68.27/Bbl included a realized gain on derivatives of $22.68/Bbl. The Company's natural gas price of $3.34/Mcf included a realized gain on derivatives of $0.39/Mcf. During the nine months ended September 30, 2015, Long Run's oil price including financial derivative contracts of $68.44/Bbl included a gain on the derivative contract of

$19.83/Bbl. The Company's natural gas price including derivatives of $3.27/Mcf included a realized gain on the derivative contracts of $0.39/Mcf.

Operating Results

Operating Netback & Funds Flow from Operations

	Q3 2015		Q3 2014	
	$000s	**$/Boe**	$000s	$/Boe
Revenues	**72,271**	**25.56**	166,978	52.16
Royalties	**(6,312)**	**(2.23)**	(19,377)	(6.05)
	65,959	**23.33**	147,601	46.11
Realized gain (loss) on derivatives	**20,486**	**7.25**	(4,529)	(1.42)
Transportation costs	**(3,995)**	**(1.41)**	(5,272)	(1.65)
Operating costs	**(30,031)**	**(10.62)**	(37,238)	(11.63)
Operating netback	**52,419**	**18.55**	100,562	31.41
General and administration	**(7,654)**	**(2.71)**	(12,537)	(3.92)
Interest	**(9,196)**	**(3.25)**	(7,566)	(2.36)
Exploration expenses	**-**	**-**	(254)	(0.08)
Capital and other taxes	**(92)**	**(0.03)**	(6)	0.00
Funds flow from operations[1]	**35,477**	**12.56**	80,199	25.05

[1] *See Non-GAAP Measures section.*

	Nine months ended September 30			
	2015		2014	
	$000s	**$/Boe**	$000s	$/Boe
Revenues	**247,031**	**26.95**	477,542	59.56
Royalties	**(19,033)**	**(2.08)**	(55,441)	(6.91)
	227,998	**24.87**	422,101	52.65
Realized gain (loss) on derivatives	**62,763**	**6.85**	(22,108)	(2.76)
Transportation costs	**(14,200)**	**(1.55)**	(16,102)	(2.01)
Operating costs	**(107,422)**	**(11.72)**	(111,046)	(13.85)
Operating netback	**169,139**	**18.45**	272,845	34.03
General and administration	**(21,989)**	**(2.40)**	(30,400)	(3.79)
Interest	**(25,695)**	**(2.80)**	(17,989)	(2.24)
Exploration expenses	**(4)**	**-**	(772)	(0.10)
Capital and other taxes	**(92)**	**(0.01)**	(6)	0.00
Funds flow from operations[1]	**121,359**	**13.24**	223,678	27.90

[1] *See Non-GAAP Measures section.*

Third quarter 2015 compared to third quarter 2014

During the third quarter of 2015, funds flow from operations was $35.5 million, a decrease of $44.7 million from the third quarter of 2014 primarily resulting from the following:

- Lower commodity prices, excluding derivatives, decreased revenue by $55.7 million. Of this total, $31.3 million was attributable to lower oil prices, $13.7 million to lower natural gas prices and $10.4 million to lower NGLs prices; and

- Lower oil production decreased revenue by $40.9 million as a result of reduced capital spending in 2015 at Peace River and Redwater.

Partially offset by:

- Higher NGLs production increased revenue by $2.4 million. Increased production volumes were attributable to the Deep Basin assets acquired through our acquisition of Crocotta Energy Inc. (“Crocotta”) on August 6, 2014 and our successful Cardium drilling in the Deep Basin area;

- Royalties were $13.1 million lower in 2015, averaging 9% of revenue compared to 12% in 2014. Lower royalties resulted from lower commodity prices as well as lower oil production volumes;

- The realized gain on financial derivative contracts of $20.5 million compares to a loss of $4.5 million in 2014. During 2015, Long Run realized gains on oil derivative contracts of $16.7 million and on natural gas derivative contracts of $4.0 million;

- Operating costs were $7.2 million lower in 2015. Operating costs for 2015 averaged $10.62/Boe compared to $11.63/Boe in 2014, reflecting lower fuel, chemical and trucking costs; and

- General and administration expense decreased $4.9 million in 2015. Transaction costs in 2015 of $1.3 million related to the Private Placement with Maple Marathon, compared to 2014 transaction costs of $4.8 million primarily related to the Crocotta acquisition. Excluding transaction costs, general and administration expense averaged $2.22/Boe in 2015 compared to $2.42/Boe in 2014.

Nine months ended September 30, 2015 compared to nine months ended September 30, 2014

During the first nine months of 2015, funds flow from operations was $121.4 million, a decrease of $102.3 million from the first nine months of 2014 primarily resulting from the following:

- Lower commodity prices, excluding derivatives, decreased revenue by $184.9 million. Of this total, $109.4 million was attributable to lower oil prices, $47.9 million to lower natural gas prices and $28.3 million to lower NGLs prices;

- Lower oil production decreased revenue by $85.3 million as a result of reduced capital spending in 2015 at Peace River and Redwater; and

- Interest expense was $7.7 million higher in 2015, due mainly to a higher average outstanding debt balance during the period. Interest rates are anticipated to average approximately 6% in 2015.

Partially offset by:

- Higher natural gas and NGLs production increased revenue by $39.6 million. Higher production volumes were attributable to the Deep Basin acquisitions made in 2014 and our successful Cardium drilling programs over the past year. Of the total revenue increase, natural gas production contributed $24.2 million and NGLs production contributed $15.4 million;

- Royalties were $36.4 million lower in 2015, averaging 8% of revenue compared to 12% in 2014. Lower royalties resulted from lower commodity prices as well as lower oil production volumes. Annual royalties are expected to average 8-9% for 2015;

- The realized gain on financial derivative contracts of $62.8 million compares to a loss of $22.1 million in 2014. During 2015, Long Run realized gains on oil derivative contracts of $50.4 million and on natural gas derivative contracts of $12.6 million;

- Operating costs were $3.6 million lower in 2015. Operating costs averaged $11.72/Boe compared to $13.85/Boe in 2014, reflecting the addition of the lower cost Deep Basin assets and lower utilities, fuel and chemical costs. Operating costs are expected to average approximately $12.00-$12.25/Boe for 2015; and

- General and administration expense decreased $8.4 million in 2015. General and administration expense included transaction costs in 2015 related to the Private Placement of $1.3 million, compared to 2014 transaction costs of $6.8 million related to the Deep Basin acquisitions. Excluding transaction costs, general and administration expense averaged $2.26/Boe in 2015 compared to $2.95/Boe in 2014, as a result of lower employee costs. General and administration expense is expected to average approximately $2.50/Boe for 2015, excluding transaction costs.

Other Income & Expenses

			Nine months ended September 30	
($000s)	**Q3 2015**	Q3 2014	**2015**	2014
Unrealized gain (loss) on derivatives	**(177)**	33,737	**(35,239)**	23,926
Share-based compensation	**(960)**	(525)	**(2,733)**	(1,700)
Accretion and other	**(4,072)**	(3,025)	**(9,412)**	(7,806)
Depletion and depreciation	**(54,363)**	(65,567)	**(173,050)**	(165,690)
Gain (loss) on disposal of assets	**4,037**	9,750	**(702)**	19,434
Impairments	**(285,000)**	-	**(285,000)**	-
Deferred income tax recovery (expense)	**-**	(13,925)	**6,765**	(23,585)
	(340,535)	(39,555)	**(499,371)**	(155,421)
Funds flow from operations[1]	**35,477**	80,199	**121,359**	223,678
Net earnings (loss)	**(305,058)**	40,644	**(378,012)**	68,257

[1] See Non-GAAP Measures section.

Third quarter 2015 compared to third quarter 2014

In comparing the third quarter of 2015 to the third quarter of 2014:

- The unrealized loss on financial derivative contracts of $0.2 million compares to a gain of $33.7 million in 2014. In 2015, an unrealized loss of $1.5 million recognized on our natural gas derivative contracts and an unrealized loss of $0.3 million on our electricity contracts were partially offset by an unrealized gain of $1.6 million on our oil derivative contracts.
- Depletion and depreciation expense of $54.4 million decreased $11.2 million due to decreased production volumes and a lower depletion rate. The depletion rate for 2015 was $19.25/Boe compared to $20.50/Boe in 2014. The lower depletion rate in 2015 reflects the impact of the impairment taken at the end of 2014.
- The gain on disposal of assets of $4.0 million compares to a gain of $9.8 million in 2014. The gain in 2015 was related primarily to the disposition of a minor non-core property in the Redwater area. The gain in 2014 related primarily to the disposition of a property in the Deep Basin.
- Impairments of $285.0 million were recorded in 2015 due to the decline in future commodity price forecasts at September 30, 2015 (Peace River - $125.0 million; Redwater - $68.0 million; Deep Basin - $64.0 million; and Kaybob - $28.0 million).
- A deferred income tax recovery was not recorded in the third quarter of 2015 due to the impact of lower commodity pricing on the estimated realization of the Company's tax pools. A deferred income tax expense of $13.9 million was recognized in 2014 on earnings before tax of $54.6 million.

Nine months ended September 30, 2015 compared to nine months ended September 30, 2014

In comparing the nine months ended September 30, 2015 to the nine months ended September 30, 2014:

- An unrealized loss on financial derivative contracts of $35.2 million compares to a gain of $23.9 million in 2014. In 2015, an unrealized loss of $28.6 million was recognized on our oil derivative contracts and a $6.6 million loss was recognized on our natural gas derivative contracts.

- Depletion and depreciation expense of $173.1 million increased $7.4 million from 2014 due to increased production volumes partially offset by a lower depletion rate. The depletion rate for 2015 was $18.90/Boe compared to $20.70/Boe in 2014. The lower depletion rate in 2015 reflects the impact of the impairment taken at the end of 2014.

- The loss on disposal of assets of $0.7 million compares to a gain of $19.4 million in 2014. The loss in 2015 relates to minor dispositions during the period. The gain in 2014 related primarily to the disposition of our heavy oil properties at Lloydminster, an overriding royalty disposition in our Peace River area, and a minor property within the Deep Basin area.

- Impairments of $285.0 million in 2015 were recorded due to the decline in future commodity price forecasts at September 30, 2015 (Peace River - $125.0 million; Redwater - $68.0 million; Deep Basin - $64.0 million; and Kaybob - $28.0 million).

- A deferred income tax recovery of $6.8 million was recorded in 2015 on a loss before tax of $384.7 million. The deferred income tax recovery was limited to $6.8 million due to the impact of lower commodity pricing on the estimated realization of the Company's tax pools. A deferred income tax expense of $23.6 million was recognized in 2014 on earnings before tax of $91.8 million.

Liquidity and Capital Resources

Net Debt

($000s)	**September 30, 2015**	December 31, 2014
Bank debt – current	**245,000**	100,000
– long-term	**350,618**	511,717
	595,618	611,717
Working capital deficiency	**8,150**	52,881
Convertible debentures – face value	**75,000**	75,000
Net debt[1]	**678,768**	739,598

[1] *See Non-GAAP Measures section.*

The Company's net debt at September 30, 2015 decreased $60.8 million from December 31, 2014, primarily due to proceeds from dispositions and funds flow from operations exceeding capital expenditures.

The capital intensive nature of the Company's activities generally results in the Company carrying a working capital deficit, as reflected in the net debt calculation. The Company maintains sufficient unused credit facilities to satisfy working capital deficiencies. At September 30, 2015, Long Run had drawn $595.6 million against the Company's credit facilities and had letters of credit outstanding totalling $7.3 million, leaving $92.1 million of borrowing capacity available.

Credit Facilities

On May 29, 2015, the Company completed the semi-annual review of its credit facilities with its banking syndicate. Credit facilities were maintained at $695 million. The amended credit facilities consist of a $410 million revolving syndicated facility, a $40 million revolving operating facility and a $245 million non-revolving syndicated facility. At September 30, 2015, $595.6 million was drawn against the credit facilities (December 31, 2014 - $611.7 million).

The revolving syndicated facility and the revolving operating facility, which comprise the Company's borrowing base facilities, are reviewed semi-annually and terminate on May 31, 2017 unless extended. The non-revolving syndicated facility is due on May 29, 2016. Prior to May 29, 2016, proceeds received on the aggregate sale of assets in excess of $30 million are required to be applied against the non-revolving syndicated facility. Subsequent to September 30, 2015, the Company voluntarily repaid $20 million of the non-revolving syndicated facility utilizing third quarter disposition proceeds.

Long Run expects 2015 funds flow from operations of $135 - $140 million to exceed net capital expenditures of $70 million and intends to use part of this excess to repay a portion of our non-revolving syndicated facility. On closing of the proposed Private Placement, the proceeds of $100 million will be used to further reduce indebtedness under the non-revolving syndicated facility. The remaining balance on the non-revolving syndicated facility is planned to be repaid through asset dispositions.

Under the borrowing base facilities, total borrowings cannot exceed the borrowing base, which is determined by the lenders on a semi-annual basis, or upon the occurrence of a material event. The level of the borrowing base is determined by the lenders based upon their review of, among other things, the Company's reserves and the value thereof, utilizing commodity prices determined by the lenders which may be different than those utilized by the Company's independent reserve evaluator. The semi-annual review by the Company's credit facilities is currently in progress and is expected to be completed by November 30, 2015.

Security for the credit facilities at September 30, 2015 included a demand debenture for $1.5 billion which provides for a first ranking security interest and floating charge over all of the assets and property of the Company.

The credit facilities bear interest at the prime rate or Libor rate, plus a margin, and in respect of banker's acceptances requires the payment of a stamping fee equal to a margin. The margins applicable to the borrowing base facilities range from 1.00% per annum to 4.50% per annum, based upon the ratio of the Company's debt to earnings before interest, taxes, exploration expenses, and all non-cash items including depletion and depreciation, unrealized gain/loss on derivatives, gain/loss on sale of assets, accretion and share based compensation ("Bank EBITDA"). Interest and fees payable on the non-revolving syndicated facility are based upon the borrowing base facility margins plus 3.50%. For the nine months ended September 30, 2015, the effective interest rate, including standby and other fees, was 4.9% (September 30, 2014 – 4.4%).

At September 30, 2015, the Company was in compliance with all covenants, obligations and conditions of its credit agreement. The covenants under the credit facilities include covenants which relate to senior debt and total debt to Bank EBITDA, interest coverage, permitted dispositions, permitted hedging and permitted distributions (regular cash dividends to shareholders are not permitted until the $245 million non-revolving syndicated facility has been repaid).

The bank covenants require a senior debt to Bank EBITDA and total debt to Bank EBITDA to be less than 4.50x from May 31, 2015 to March 31, 2016 and less than 5.0x from April 1, 2016 to June 30, 2016 (September 30, 2015 – 2.70:1). After June 30, 2016, the bank covenants require a senior debt to Bank EBITDA ratio of less than 3.0x and a total debt to Bank EBITDA ratio of less than 3.5x. The interest coverage ratio, defined as Bank EBITDA to interest expense, is required to be greater than 2.75x until June 30, 2016 and greater than 3.5x for each fiscal quarter after June 30, 2016 (September 30, 2015 – 6.62:1). The convertible debentures issued in January 2014 are not considered debt for the debt to Bank EBITDA ratio calculations under the credit agreement. Commodity hedges are permitted on up to 75% of 2015 forecasted oil and NGLs and natural gas production net of royalties (2016 - 75%; 2017 - 50%). Interest rate hedges are permitted up to 75% of the total debt balance. Further details on the calculations of the covenants can be found in the Company's credit facility agreement filed on SEDAR at www.sedar.com on June 3, 2015 under the Company's profile.

Convertible Debentures

On January 28, 2014, the Company issued convertible unsecured subordinated debentures (the "convertible debentures") in the principal amount of $75 million at par. The convertible debentures bear interest at an annual rate of 6.40%, payable semi-annually in arrears. Prior to maturity on January 31, 2019, the convertible debentures are convertible into Common Shares at a conversion price of $7.40 per Common Share, subject to adjustments in certain events.

Share Capital

# of units (000s)	**November 16, 2015**	September 30, 2015	December 31, 2014
Common Shares	193,498	193,498	193,498
Options	7,817	7,972	8,879
Restricted Awards	4,614	4,764	-

In January 2015, a total of 5.2 million restricted awards were granted. Each restricted award entitles the holder to a Long Run Common Share or the value of a Long Run Common Share (subject to certain adjustments, including for dividends paid on the Common Shares) on the vesting date. The Company currently intends to settle the awards with equity. The awards vest equally over three years, on the first, second and third anniversaries of the grant date.

On August 2, 2015, the Company entered into a private placement agreement with Maple Marathon and MIE. On November 8, 2015, Long Run entered into an amended and restated agreement, pursuant to which Long Run will issue to Maple Marathon, by way of Private Placement, 125,000,000 Units at an issue price of $0.80 per Unit for gross proceeds of $100 million.

Each Unit will be comprised of one common share of Long Run and 0.728 of a common share purchase Warrant. Each Warrant will entitle the holder to acquire one common share of Long Run at an exercise price of $1.10 for a period of 12 months from closing of the Private Placement, for additional proceeds of approximately $100 million to Long Run, if exercised. The closing of the Private Placement is subject to various conditions including obtaining shareholder and regulatory approvals.

The closing of the Private Placement will cause the payment dates applicable to the outstanding incentive awards to be accelerated such that the value attaching to outstanding awards will be settled upon closing of the Private Placement.

Dividends

No dividends were declared or paid to shareholders during the second or third quarters of 2015. The monthly dividend was suspended in February 2015 as the Company focuses on strengthening the balance sheet. During the nine months ended September 30, 2015, $3.4 million in dividends had been declared and paid (September 30, 2014 - $45.9 million in dividends were declared, of which $39.1 million had been paid).

Capital Structure

The Company's primary capital management objective is to strengthen our financial position and financial flexibility. To manage the capital structure, the Company may adjust capital spending, dispose of properties, issue new shares, issue new debt or repay existing debt.

In managing its capital structure, the Company monitors financial metrics as indicators of overall financial strength. The financial metrics the Company currently monitors include net debt to funds flow from operations and debt to debt plus equity. The Company's objective is to target net debt to funds flow from operations at or below a ratio of 1.5 and debt to debt plus equity at a ratio at or below 0.4. For the calculation of these metrics, see Note 11 to the interim financial statements for the nine months ended September 30, 2015.

The net debt to funds flow from operations at September 30, 2015 was calculated based on third quarter funds flow annualized. The resulting net debt to funds flow from operations of 4.8 times reflects the lower commodity prices experienced in the third quarter. At September 30, 2015, the Company had a debt to debt plus equity ratio of 0.66 times. Long Run is focused on improving its capital structure. The Company's plan to repay its non-revolving syndicated facility through the Private Placement proceeds, asset dispositions and excess funds flow from operations over net capital expenditures is expected to improve Long Run's target metrics.

Contractual Obligations and Contingencies

Commitments

($000s)	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**
Operating leases	1,166	4,329	6,041	7,753	7,482	50,604	77,375
Processing	1,059	6,024	6,024	6,024	6,024	31,941	57,096
Transportation	3,155	15,414	14,031	9,967	4,712	9,493	56,772
Fractionation	731	2,843	2,653	650	-	-	6,877
Capital	4,559	8,837	6,168	253	-	-	19,817
Commitments	10,670	37,447	34,917	24,647	18,218	92,038	217,937

At September 30, 2015, the Company was committed under operating leases for office space, contracts related to the processing of natural gas, transportation of oil and natural gas and NGLs, fractionation of natural gas liquids, and capital commitments for drilling rig services. Commitments increased by $26.3 million from December 31, 2014 as a result of an increase in drilling, processing, transportation and fractionation commitments.

Other than the operating leases, the Company has no off-balance sheet financing arrangements.

Contingencies

The Company is involved in various claims and legal actions arising in the normal course of business. The Company does not expect that the outcome of these proceedings will have a material adverse effect on the Company as a whole.

Risk Management

Long Run is engaged in the development, acquisition, exploration and production of oil and natural gas in western Canada. The Company is exposed to a number of risks, both financial and operational, through the pursuit of its strategic objectives. Actively managing these risks improves the ability to effectively execute our business strategy. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services. Financial risks also include third party credit risk and liquidity risk. Operational risks include reservoir performance uncertainties, competition, and regulatory, environment and safety concerns. The nature of these risks has not changed substantially since December 31, 2014.

For a further and more in-depth discussion of risk management, see the Company's annual financial statements and MD&A for the year ended December 31, 2014 and the Company's Annual Information Form for the year ended December 31, 2014.

Commodity Price

Oil and natural gas prices have been and are expected to remain volatile due to market uncertainties over the supply and demand of these commodities due to various factors including the current state of world economies, OPEC actions and ongoing credit and liquidity concerns. Depressed commodity prices have had and will continue to have a significant effect on the Company's revenue, funds flow from operations available for capital expenditures and repayment of indebtedness and other matters.

To partially mitigate exposure to commodity price risk, the Company enters into various financial derivative instruments. The Company has entered into oil and natural gas derivative contracts, including costless collars, fixed price contracts, and calls. At September 30, 2015, the Company had contracts for oil volumes of 4,500 Bbl/d for the remainder of 2015 and 1,000 Bbl/d contracted for 2016. At September 30, 2015, the Company had contracts for natural gas volumes of approximately 62.6 MMcf/d for the remainder of 2015 and 42.6 MMcf/d contracted for 2016. Further details on the derivative contracts can be found in Note 14 of the interim financial statements for the nine months ended September 30, 2015.

In the first nine months of 2015, the Company realized a $62.8 million gain as a result of its commodity price risk management. The realized gain included a $50.4 million gain on oil financial derivative contracts and a $12.6 million gain on natural gas contracts. In the first nine months of 2015, the Company recognized an unrealized loss on oil financial derivative contracts of $28.6 million and an unrealized loss on natural gas contracts of $6.6 million. At September 30, 2015, the fair value of oil derivatives was an asset of $21.3 million and the fair value of natural gas derivatives was an asset of $8.9 million.

Liquidity Risk

Liquidity risk arises through excess financial obligations due over available financial assets at any point in time. The Company's objective in managing liquidity risk is to maintain sufficient capital in order to meet its current and future liquidity requirements.

At September 30, 2015, $595.6 million was drawn against the Company's credit facilities, with $92.1 million of borrowing capacity available. On May 29, 2016, the Company's non-revolving syndicated facility of $245.0 million is due. The Company currently plans to repay the non-revolving syndicated facility through asset dispositions, funds flow from operations exceeding capital expenditures and proceeds from the proposed Private Placement (see Note 10). The Company's ability to continue as a going concern and discharge its obligations will require additional equity or debt financing and/or proceeds from asset sales. Management is actively pursuing sources of financing, including the proposed Private Placement, and has initiated a formal asset disposition process. Though management has been successful in securing sufficient financing in the past, there can be no assurance that it will be able to do so in the future.

Critical Accounting Judgments, Estimates and Accounting Policies

For a full understanding of the Company's critical accounting judgments, estimates and accounting policies, the following should be read in conjunction with the annual audited financial statements and MD&A for the year ended December 31, 2014.

Critical Accounting Estimates

The Company is required to make judgments, estimates and assumptions in the application of accounting policies that could have a significant impact on its financial results. Actual results may differ from those estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Further details on the basis of presentation and significant accounting policies can be found in the annual financial statements and MD&A for the year ended December 31, 2014. There have been no significant changes to the accounting policies since December 31, 2014.

Future Accounting Pronouncements

In September 2015, the International Accounting Standards Board issued an amendment to IFRS 15, Revenue from Contracts with Customers ("IFRS 15"), deferring the effective date by one year to annual periods beginning on or after January 1, 2018. IFRS 15 clarifies the principles for recognizing revenue from contracts with customers, and provides a model for the recognition and measurement of sales of certain non-financial assets. The adoption of this standard is not expected to have a material impact on the Company's financial statements.

A description of standards and interpretations that will be adopted by the Company in future periods can be found in Note 4 of the annual financial statements for the year ended December 31, 2014.

Control Environment

Disclosure Controls and Procedures

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Internal Controls over Financial Reporting

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles applicable to the Company.

The Company is required to disclose any change in the Company's internal controls over financial reporting that occurred during the Company's most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Detailed Quarterly Results

The Corporation's quarterly funds flow from operations is significantly impacted by changes in production volumes, fluctuations in commodity prices, exchange rates and realized gains and losses on financial derivative contracts. In addition to these items, net earnings are impacted by impairments and unrealized gains and losses on financial derivative contracts. Acquisitions and divestitures can also have a significant impact on Long Run's results. The following significant transactions have impacted the Company's quarterly results:

- During the third quarter of 2015, Long Run recorded property impairment charges of $285.0 million at Peace River, Redwater, Deep Basin and Kaybob. The impairment charges were a result of the drop in forecast commodity prices at September 30, 2015.

- During the first quarter of 2015, Long Run suspended its monthly dividend. The dividend was suspended in order to focus on strengthening the balance sheet and directing funds to maintaining operational momentum in our key areas.

- During the fourth quarter of 2014, Long Run recorded property impairment charges of $400.0 million ($300.0 million after tax) at Peace River, the Deep Basin, Redwater and Kaybob. The impairment charges were a result of the drop in forecast commodity prices at December 31, 2014.

- During the third quarter of 2014, Long Run completed the acquisition of Crocotta on August 6, 2014, for total consideration of $346.9 million. Production from the properties averaged approximately 6,200 Boe/d from August 6 through December 31, 2014, in the Deep Basin area.

- During the second quarter of 2014, Long Run completed the Deep Basin property acquisition on May 30, 2014, for total consideration of $228.8 million. Production from the property averaged approximately 5,200 Boe/d from May 30 through December 31, 2014, in the Deep Basin and Redwater areas.

	2015			2014				2013
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Funds flow from operations[1] *($000s)*	**35,477**	45,924	39,958	68,178	80,199	73,429	70,050	55,934
Per share, basic[1]	**0.18**	0.24	0.21	0.35	0.45	0.55	0.56	0.45
Per share, diluted[1]	**0.18**	0.24	0.21	0.35	0.45	0.54	0.56	0.44
Net earnings (loss) *($000s)*	**(305,058)**	(50,136)	(22,818)	(258,652)	40,644	20,842	6,771	(5,531)
Per share, basic	**(1.58)**	(0.26)	(0.12)	(1.34)	0.23	0.16	0.05	(0.04)
Per share, diluted	**(1.58)**	(0.26)	(0.12)	(1.34)	0.23	0.15	0.05	(0.04)
Capital *($000s)*								
Drilling and completion	**13,434**	4,484	31,577	40,928	52,530	34,851	75,114	30,750
Plant and facilities	**4,487**	1,967	12,202	26,935	19,740	16,441	23,370	8,760
Geological and geophysical	**14**	42	778	247	1,951	4,295	939	566
Other assets	**1,432**	2,277	758	1,984	1,538	1,743	1,425	1,561
Capital expenditures	**19,367**	8,770	45,315	70,094	75,759	57,330	100,848	41,637
Net acquisitions (dispositions)	**(17,914)**	(9,530)	(1,392)	(1,797)	(8,147)	213,716	(3,679)	86,328
Capital investment	**1,453**	(760)	43,923	68,297	67,612	271,046	97,169	127,965
Wells drilled *(net)*								
Peace - Montney	**-**	-	5.0	1.0	12.0	11.0	17.5	9.5
- Other	**-**	-	-	-	-	-	2.0	-
Deep Basin - Edson	**-**	-	3.0	2.0	3.0	-	-	-
- Kakwa/Elmworth	**-**	-	1.0	6.0	-	-	-	-
Redwater - Viking	**12.0**	-	-	1.0	6.0	10.0	27.0	1.0
- Other	**-**	-	-	-	-	1.0	-	-
Other	**-**	-	-	-	-	-	1.0	1.0
Total	**12.0**	-	9.0	10.0	21.0	22.0	47.5	11.5
Production								
Liquids *(Bbl/d)*								
Light oil	**7,711**	9,059	10,242	11,895	12,708	11,808	11,491	11,811
Heavy oil	**279**	370	315	235	363	668	1,193	1,440
NGLs	**4,277**	4,659	5,210	5,609	3,031	2,038	1,584	1,520
	12,267	14,088	15,767	17,739	16,102	14,514	14,268	14,771
Natural Gas *(Mcf/d)*	**110,799**	122,214	119,007	112,576	112,161	78,524	68,071	73,392
Total *(Boe/d)*	**30,733**	34,457	35,602	36,502	34,795	27,602	25,613	27,003
Production by area *(Boe/d)*								
Peace - Montney	**7,497**	8,767	9,527	10,661	10,918	9,340	9,294	11,500
- Other	**2,046**	2,170	2,651	2,650	3,054	3,160	3,579	2,169
Deep Basin - Edson	**6,430**	7,366	7,498	7,665	4,654	338	19	-
- Kakwa/Elmworth	**4,854**	5,706	4,942	3,579	3,207	1,433	-	-
Redwater - Viking	**2,942**	3,295	3,749	4,451	5,122	5,617	5,365	6,285
- Other	**2,903**	3,124	3,279	3,242	3,196	2,758	2,819	2,327
Boyer	**2,717**	2,659	2,523	2,727	2,929	3,046	2,733	2,861
Other	**1,344**	1,370	1,433	1,527	1,715	1,910	1,804	1,861
Total	**30,733**	34,457	35,602	36,502	34,795	27,602	25,613	27,003

	2015			2014				2013
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Benchmark pricing								
WTI *(US$/Bbl)*	**46.44**	57.96	48.57	73.12	97.21	102.98	98.68	97.46
Edmonton Light Sweet *(CDN$/Bbl)*	**56.27**	67.73	51.85	75.65	97.18	105.62	99.83	86.58
AECO *($/Mcf)*	**2.84**	2.66	2.76	3.75	4.02	4.69	5.72	3.53
US$/CDN$ exchange rate	**1.31**	1.23	1.24	1.13	1.09	1.09	1.10	1.05
Prices, excluding derivatives								
Liquids *($/Bbl)*								
Light oil	**45.78**	58.53	42.32	66.73	88.08	97.50	91.24	75.06
Heavy oil	**40.59**	53.33	37.36	60.71	81.47	81.79	78.90	62.69
NGLs	**20.74**	24.48	22.50	30.02	57.98	72.76	86.87	69.21
Total	**36.93**	47.13	35.67	55.04	82.26	93.30	89.72	73.25
Natural Gas *($/Mcf)*	**2.95**	2.89	2.80	4.13	4.29	4.89	5.96	3.73
Total *($/Boe)*	**25.56**	29.80	25.38	39.71	52.16	63.17	65.89	50.24
Prices, including derivatives								
Oil *($/Bbl)*	**68.27**	72.03	65.34	79.35	84.66	89.59	85.89	71.14
NGLs *($/Bbl)*	**20.74**	24.48	22.50	30.02	57.98	72.76	86.87	69.21
Natural Gas *($/Mcf)*	**3.34**	3.30	3.17	4.15	4.23	4.61	5.53	4.04
Total *($/Boe)*	**32.81**	35.04	33.45	43.92	50.75	59.13	62.67	49.78
Netback *($/Boe)*								
Revenues	**25.56**	29.80	25.38	39.71	52.16	63.17	65.89	50.24
Royalties	**(2.23)**	(2.04)	(1.97)	(4.42)	(6.05)	(7.01)	(8.01)	(7.33)
Realized gain (loss) on derivatives	**7.25**	5.24	8.07	4.21	(1.42)	(4.04)	(3.22)	(0.46)
Transportation costs	**(1.41)**	(1.53)	(1.69)	(1.75)	(1.65)	(2.10)	(2.41)	(2.00)
Operating costs	**(10.62)**	(11.55)	(12.85)	(12.71)	(11.63)	(14.98)	(15.70)	(13.36)
Operating Netback	**18.55**	19.92	16.94	25.04	31.41	35.04	36.55	27.09
G&A	**(2.71)**	(2.53)	(2.00)	(2.32)	(3.92)	(3.64)	(3.79)	(2.82)
Interest	**(3.25)**	(2.75)	(2.46)	(2.39)	(2.36)	(2.19)	(2.13)	(1.73)
Capital and other taxes	**(0.03)**	-	-	-	-	-	-	-
Corporate Netback	**12.56**	14.64	12.48	20.33	25.13	29.21	30.63	22.54
Funds flow from operations[1] *($000s)*								
Revenues	**72,271**	93,436	81,324	133,354	166,978	158,678	151,886	124,816
Royalties	**(6,312)**	(6,400)	(6,321)	(14,835)	(19,377)	(17,598)	(18,466)	(18,213)
Realized gain (loss) on derivatives	**20,486**	16,432	25,845	14,145	(4,529)	(10,157)	(7,422)	(1,145)
Transportation costs	**(3,995)**	(4,785)	(5,421)	(5,891)	(5,272)	(5,287)	(5,543)	(4,971)
Operating costs	**(30,031)**	(36,206)	(41,184)	(42,684)	(37,238)	(37,614)	(36,194)	(33,198)
	52,419	62,477	54,243	84,089	100,562	88,022	84,261	67,289
G&A	**(7,654)**	(7,929)	(6,406)	(7,793)	(12,537)	(9,134)	(8,729)	(7,017)
Interest	**(9,196)**	(8,624)	(7,875)	(8,038)	(7,566)	(5,507)	(4,916)	(4,300)
Other	**(92)**	-	(4)	(80)	(260)	48	(566)	(38)
	35,477	45,924	39,958	68,178	80,199	73,429	70,050	55,934

[1] *See Non-GAAP Measures section.*

Non-GAAP Measures

The MD&A contains terms commonly used in the oil and natural gas industry, such as funds flow from operations, funds flow from operations per share and net debt. These terms are not defined by IFRS and therefore may not be comparable to similar measures presented by other companies. There are measures commonly used in the oil and gas industry and by Long Run to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. These terms should not be considered an alternative to, or more meaningful than, cash provided by operating activities or net earnings as determined in accordance with IFRS as indicators of Long Run's performance.

Funds Flow from Operations

	2015			2014				2013
($000s)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Cash flow from operating activities	**28,057**	37,585	48,832	80,866	78,006	67,280	59,781	65,932
Change in non-cash working capital	**5,338**	7,975	(11,491)	(18,865)	(996)	5,452	8,923	(11,758)
Abandonment costs	**2,082**	364	2,617	6,177	3,189	697	1,346	1,760
Funds flow from operations	**35,477**	45,924	39,958	68,178	80,199	73,429	70,050	55,934
Weighted average outstanding shares *(000s)*								
- Basic	**193,498**	193,498	193,498	193,497	176,318	134,291	125,730	125,629
- Diluted	**193,498**	193,498	193,498	193,497	177,003	135,437	126,129	126,245
Funds flow from operations per share *($/share)*								
- Basic	**0.18**	0.24	0.21	0.35	0.45	0.55	0.56	0.45
- Diluted	**0.18**	0.24	0.21	0.35	0.45	0.54	0.56	0.44

	Nine months ended September 30	
($000s)	**2015**	2014
Cash flow from operating activities	**114,474**	205,067
Change in non-cash working capital	**1,822**	13,379
Abandonment costs	**5,063**	5,232
Funds flow from operations	**121,359**	223,678
Weighted average outstanding shares *(000s)*		
- Basic	**193,498**	145,632
- Diluted	**193,498**	146,511
Funds flow from operations per share *($/share)*		
- Basic	**0.63**	1.54
- Diluted	**0.62**	1.53

Net Debt

($000s)	September 30, 2015	December 31, 2014
Bank debt	**595,618**	611,717
Working capital deficiency		
Accounts payable and accrued liabilities	**64,524**	132,439
Accounts receivable	**(40,109)**	(65,135)
Prepaid expenses and deposits	**(16,265)**	(14,423)
Convertible debentures – face value	**75,000**	75,000
Net Debt	**678,768**	739,598

Advisory

Forward-Looking Statements

This document contains forward-looking statements and forward-looking information (collectively "forward-looking information") within the meaning of applicable securities laws relating to the Company's plans and other aspects of Long Run's anticipated future operations, management focus, objectives, strategies, financial, operating and production results and opportunities, including 2015 capital expenditure budget, nature and timing of expenditures and method of funding, drilling and development plans and the timing thereof, 2015 average production guidance, expected 2015 funds flow from operations and expectation that it will exceed net 2015 capital expenditures, use of proceeds from the Private Placement, dispositions and funds flow from operations in excess of net capital expenditures, response from EOR projects and possible effects thereof, expectation that unused credit facilities will be sufficient to satisfy working capital deficiencies, plans to repay bank debt and targeted debt reduction in the year, payment of outstanding incentive awards upon closing of the Private Placement, expected 2015 operating costs, royalty rates and general and administrative expenses, and plans to repay non-revolving syndicated facility and timing of semi-annual review by lending syndicate. Forward-looking information typically uses words such as "anticipate", "believe", "project", "expect", "goal", "plan", "intend" or similar words suggesting future outcomes, statements that actions, events or conditions "may", "would", "could" or "will" be taken or occur in the future. Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Company operates; the timely receipt of any required regulatory approvals; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; the ability of the Company to obtain financing and access capital on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of the Company to secure adequate product transportation; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company operates; the ability of the Company to successfully market its oil and natural gas products; expectations and assumptions concerning prevailing and future commodity prices, exchange rates, interest rates, applicable royalty rates and tax laws; future production rates and estimates of operating costs; performance of existing and future wells; reserve and resource volumes; anticipated timing and results of capital expenditures; the success obtained in drilling new wells; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the state of the economy and the exploration and production business; results of operations; business prospects and opportunities; the availability and cost of financing, labor and services; the impact of increasing competition and the effects thereof. Included herein is an estimate of Long Run's 2015 funds flow from operations based on assumptions provided herein and WTI US$50.00/Bbl, AECO $2.60/GJ and FX CDN/USD $0.79 and other assumptions utilized in arriving at Long Run's capital budget. To the extent such estimate constitutes a financial outlook, it was approved by management November 16, 2015 and is included herein to provide readers with an understanding of the anticipated funds available to fund its capital expenditures, debt reduction and for other purposes and readers are cautioned that the information may not be appropriate for other purposes.

These forward-looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the Company's objectives, goals or future plans are forward-looking statements. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties including, without limitation, risks associated with oil and natural gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, Long Run's actual results may differ materially from those expressed in, or implied by, the forward-looking statements.

Readers are cautioned that the foregoing list of factors and assumptions is not exhaustive. Additional information on these and other factors that could affect Long Run's operations and financial results are included elsewhere herein and in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), or at Long Run's website (www.longrunexploration.com). Furthermore, the forward-looking statements contained herein are made as at the date hereof and Long Run does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Oil & Natural Gas Information

Oil and natural gas reserves and volumes are converted to a common unit of measure on a basis of six thousand cubic feet of natural gas to one barrel of oil. Boes may be misleading, particularly if used in isolation. The forgoing conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different than the energy equivalency of six to one, utilizing a conversion on a six to one basis may be misleading as an indication of value.

Operating netback per Boe is calculated by subtracting royalties, transportation and operating costs from revenues, including the realized gain (loss) on financial derivatives and dividing by total production. Corporate netback per Boe is calculated as operating netback less interest and general and administration expense and divided by total production.

Abbreviations

Oil and Natural Gas Liquids

Bbl	Barrels
MBbl	thousand barrels
MMBbl	million barrels
Bbl/d	barrels per day
NGLs	natural gas liquids
Boe	barrels of oil equivalent
MBoe	thousand barrels of oil equivalent
Boe/d	barrels of oil equivalent per day
Liquids	light oil, heavy oil, and NGLs

Natural Gas

MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units

Additional Information

Additional information relating to Long Run, including Long Run's Annual Information Form, can be accessed on-line on SEDAR at www.sedar.com, or from the Company's website at www.longrunexploration.com.