

LONG RUN EXPLORATION LTD.

Management's Discussion and Analysis

June 30, 2014



Management's Discussion and Analysis

For the three and six months ended June 30, 2014

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 June 30, 2014 and the audited financial statements and MD&A for the year ended December 31, 2013. The disclosure which is unchanged from the MD&A for the year ended December 31, 2013 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 conform to current year presentation.

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 August 7, 2014.

Long Run's Strategy

Long Run is engaged in the development, acquisition, exploration and production of oil and natural gas in western Canada. Specifically, the Company is focused on controlled exploitation and strategic acquisitions within the Western Canadian Sedimentary Basin. The Company's core areas are located in central and northern Alberta, including the Montney at Peace River, the Cardium and Bluesky in the Deep Basin, the Viking at Redwater and the Bluesky at Boyer.

Long Run has assembled large land blocks and has invested in crude oil and natural gas infrastructure in its key areas so as to obtain operatorship, control infrastructure and build our multi-year inventory of locations. The Company's near term strategy is to develop the potential of Long Run's oil and liquids-rich natural gas resources, selectively explore on our current land base and maintain a strong focus on cost control and efficiencies. Additionally, Long Run will continue to pursue strategic asset and corporate acquisitions of crude oil and natural gas properties, while reviewing our portfolio for potential dispositions. Long Run remains focused on portfolio management and maintaining a strong capital structure.

In 2014, the Company transitioned its business model to a balanced intermediate producer paying a monthly dividend, while continuing to provide annual per share growth to shareholders. Long Run expects to fund capital expenditures and dividend payments from its funds flow from operations. Pursuant to our business plan, Long Run has been active in consolidating a key position in the Deep Basin through a strategic property acquisition on May 30, 2014 and the corporate acquisition of Crocotta Energy Inc. on August 6, 2014.

Highlights and 2014 Outlook

Highlights for the three months ended June 30, 2014 include:

- Funds flow from operations was \$73.4 million (\$0.54 per share), an 8% per share increase over \$63.2 million (\$0.50 per share) in the second quarter 2013.
- Production averaged of 27,602 Boe/d, a 13% increase from 24,431 Boe/d in the second quarter of 2013.
- Increased monthly dividend by 5% from \$0.0335 per share to \$0.035 per share starting with the June 2014 dividend, payable in July 2014. Second quarter 2014 dividends declared totaled \$0.10 per share, or \$14.5 million, with a basic payout ratio of 20%.
- Commenced a focused development program following spring break-up, drilling 22.0 net wells, with a 100% success rate. Capital expenditures totaled \$57.3 million, concentrated on our Peace River Montney and Redwater Viking areas.
- Successfully closed a strategic property acquisition (the “Deep Basin Acquisition”) for approximately \$228.8 million, which provides a key entry point into the Wapiti and Pine Creek areas of Alberta. A \$120.0 million bought deal equity financing was closed in conjunction with the acquisition. Long Run’s credit facility borrowing base was increased by \$100 million to \$575 million upon closing of the transaction.

Highlights for the six months ended June 30, 2014 include:

- Funds flow from operations was \$143.5 million (\$1.10 per share), a 24% per share increase over \$111.9 million (\$0.89 per share) in 2013.
- Production averaged of 26,613 Boe/d, an 11% increase from 24,023 Boe/d in 2013.
- Successfully transitioned to a dividend plus growth model. Dividends declared in the first six months of 2014 totaled \$0.20 per share, or \$27.1 million, with a basic payout ratio of 19%.
- Executed a focused development program, drilling 69.5 net wells, with a 99% success rate. Capital expenditures totaled \$158.2 million, concentrated in our Peace River Montney and Redwater Viking areas.
- Issued \$75 million of convertible debentures to strengthen the balance sheet by providing Long Run with additional financial flexibility through the diversification of indebtedness and interest rate certainty on a portion of its debt. The convertible debentures bear an annual interest rate of 6.40% and are convertible into Long Run Common Shares at conversion price of \$7.40 per share.

Crocotta Acquisition

On August 6, 2014, the Company closed the acquisition of all of the issued and outstanding common shares of Crocotta Energy Inc. (“Crocotta”) pursuant to a plan of arrangement (the “Arrangement” or the “Crocotta Acquisition”) under the *Business Corporations Act* (Alberta). Under the Arrangement, Crocotta shareholders received a combination of Long Run Common Shares, as well as common shares and warrants of a newly established Montney-focused exploration company (“ExploreCo”). ExploreCo assets, including assets in northeast British Columbia and northwest Alberta, were excluded from Long Run’s acquisition of Crocotta.

For each Crocotta share held, shareholders of Crocotta received 0.415 of a Long Run Common Share, one common share of ExploreCo, and 0.2 arrangement warrants of ExploreCo. Each arrangement warrant entitles the holder to purchase one ExploreCo common share at a price of \$1.70 for a period of 30 days following closing of the Arrangement.

Long Run issued approximately 44 million Long Run Common Shares, based on an exchange ratio of 0.415 Long Run Common Shares for each of the 105.6 million Crocotta common shares outstanding. In addition, Long Run will assume up to \$115 million of the net debt of Crocotta, defined as bank debt plus accounts payable and accrued liabilities less accounts receivable and deposits and prepaid expenses. The borrowing base for the Company’s credit facilities was increased by \$120 million to \$695 million in conjunction with the transaction.

The Crocotta Acquisition gives Long Run a major presence in the liquids-rich natural gas Deep Basin fairway at Pine Creek, focusing on the Cardium and Bluesky formations. This acquisition, in concert with the Deep Basin Acquisition, creates a new core area which will provide exploration and development opportunities and add strategic ownership in gathering and processing infrastructure.

2014 Outlook

Long Run is focused on providing long-term value to shareholders through a sustainable dividend plus growth model. We believe maintaining a strong balance sheet and financial flexibility is key to this model. Controlled exploitation of our core assets and strategic acquisitions forms the basis of our goal of funding both capital expenditures and dividends with funds flow from operations.

Our 2014 guidance provided on June 12, 2014 in connection with the Crocotta Acquisition announcement remains unchanged. For 2014, we anticipate capital expenditures (development capital) of \$250 million, dividends of \$67 million and average production of 32,100 Boe/d. The Company maintains its expectation that 2014 net capital expenditures (excluding the Deep Basin Acquisition and Crocotta Acquisition costs) and dividend payments will be funded using funds flow from operations.

Long Run’s 2014 capital program will focus on developing current inventory in core areas, specifically the Montney at Peace River, the Viking at Redwater, and the Cardium in the Deep Basin, where the Company expects to drill 99 total net wells.

Quarterly Results Overview

| (\$000s, except per share or unless otherwise noted) | Six months ended June 30 | | 2014 | | 2013 | | | |
|--|-----------------------------|---------|----------------|---------|---------|---------|---------|---------|
| | 2014 | 2013 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 |
| Funds flow from operations ¹ | 143,479 | 111,871 | 73,429 | 70,050 | 55,934 | 62,304 | 63,227 | 48,644 |
| Per share, basic ¹ | 1.10 | 0.89 | 0.55 | 0.56 | 0.45 | 0.50 | 0.50 | 0.39 |
| Per share, diluted ¹ | 1.10 | 0.89 | 0.54 | 0.56 | 0.44 | 0.50 | 0.50 | 0.39 |
| Net earnings (loss) | 27,613 | 20,272 | 20,842 | 6,771 | (5,531) | 9,524 | 21,099 | (827) |
| Per share, basic | 0.21 | 0.16 | 0.16 | 0.05 | (0.04) | 0.08 | 0.17 | (0.01) |
| Per share, diluted | 0.21 | 0.16 | 0.15 | 0.05 | (0.04) | 0.08 | 0.17 | (0.01) |
| Dividends declared | 27,107 | - | 14,468 | 12,639 | - | - | - | - |
| Per share | 0.20 | - | 0.10 | 0.10 | - | - | - | - |
| Payout ratio ¹ | 19% | - | 20% | 18% | - | - | - | - |
| Revenues, before royalties | 310,564 | 220,823 | 158,678 | 151,886 | 124,816 | 129,923 | 117,210 | 103,613 |
| Capital expenditures | 158,179 | 141,797 | 57,330 | 100,848 | 41,637 | 93,137 | 38,878 | 102,919 |
| Net acquisitions (divestitures) | 210,036 | 19,103 | 213,716 | (3,679) | 86,328 | 3,331 | 1,158 | 17,945 |
| Production | | | | | | | | |
| Oil (Bbl/d) | 12,580 | 11,291 | 12,476 | 12,684 | 13,251 | 11,709 | 11,471 | 11,109 |
| Natural gas liquids (Bbl/d) | 1,812 | 1,182 | 2,038 | 1,584 | 1,520 | 1,478 | 1,116 | 1,249 |
| Natural gas (Mcf/d) | 73,327 | 69,297 | 78,524 | 68,071 | 73,392 | 72,634 | 71,058 | 67,516 |
| Total (Boe/d) | 26,613 | 24,023 | 27,602 | 25,613 | 27,003 | 25,293 | 24,431 | 23,611 |
| Prices, including derivatives | | | | | | | | |
| Oil (\$/Bbl) | 87.73 | 77.39 | 89.59 | 85.89 | 71.14 | 87.44 | 81.80 | 72.77 |
| Natural gas liquids (\$/Bbl) | 78.89 | 72.28 | 72.76 | 86.87 | 69.21 | 76.05 | 68.91 | 75.33 |
| Natural gas (\$/Mcf) | 5.03 | 3.76 | 4.61 | 5.53 | 4.04 | 3.23 | 3.89 | 3.63 |
| Total (\$/Boe) | 60.82 | 51.26 | 59.13 | 62.67 | 49.78 | 54.29 | 53.29 | 49.12 |
| Operating netback (\$/Boe) | 35.76 | 30.30 | 35.04 | 36.55 | 27.09 | 30.74 | 32.57 | 27.93 |

¹ See Non-GAAP measures section

Second quarter 2014 compared to second quarter 2013

Funds flow from operations for 2014 was \$73.4 million, an increase of \$10.2 million from 2013, primarily due to higher production volumes and higher commodity prices, partially offset by higher royalties and operating costs associated with the increase in production. 2014 funds flow from operations includes one month of operating results from the Deep Basin properties acquired on May 30, 2014. General and administration expenses included \$2.0 million of transaction costs associated with the acquisition.

Net income for 2014 was \$20.8 million, compared to \$21.1 million in 2013. For 2014, the higher funds flow from operations and gain on disposal of assets was offset by higher depletion expense related to the increased production volumes, and a lower unrealized gain on financial derivatives.

Six months ended June 30, 2014 compared to six months ended June 30, 2013

Funds flow from operations for 2014 was \$143.5 million, an increase of \$31.6 million from 2013, primarily due to higher production volumes and higher commodity prices, partially offset by higher royalties and operating costs associated with the increase in production volumes. 2014 funds flow from operations includes one month of operating results from the Deep Basin properties acquired on May 30, 2014. General and administration expenses included \$2.0 million of transaction costs associated with the acquisition.

Net income for 2014 was \$27.6 million, compared to a net loss of \$20.3 million in 2013. The increase in net income results from the higher funds flow from operations and a gain on disposal of assets, partially offset by higher depletion expense related to the increase in production volumes, and a higher unrealized loss on financial derivatives.

Significant Properties

Within the Western Canadian Sedimentary Basin, Long Run operates two significant light oil areas, Peace River and Redwater. During the quarter, the Company added the Deep Basin as a new core development area focused on liquids-rich natural gas. The Company also owns a significant low decline shallow gas property at Boyer in northern Alberta.

Development of the Peace River area, located in northern Alberta, is focused on the Montney oil resource play at Normandville and Girouxville. During the second quarter of 2014, Long Run invested \$33.6 million into the Peace River area and drilled 11.0 net horizontal Montney oil wells, with a 100% success rate. Second quarter 2014 production averaged 10,820 Boe/d, consisting of 6,519 Bbl/d of oil and NGLs and 25.8 MMcf/d of natural gas. In the first six months of 2014, Long Run invested \$86.5 million, drilling 30.5 net wells (28.5 Montney horizontal oil wells) with a 100% success rate, resulting in average production of 10,728 Boe/d (61% oil and NGLs). Capital expenditures for 2014 are expected to total \$120 million, including the drilling of approximately 43 net wells. The Company operates, transports, and processes all of its production within Peace River.

In the Redwater area, located near Edmonton, Alberta, development is focused on the Viking oil resource play. During the second quarter of 2014, Long Run invested \$16.6 million in the Redwater area, drilling 11.0 net wells, with a 100% success rate. Second quarter 2014 production averaged 6,588 Boe/d, consisting of 5,193 Bbl/d of oil and NGLs and 8.4 MMcf/d of natural gas. In the first six months of 2014, Long Run invested \$56.2 million, drilling 38.0 net wells with a 100% success rate, resulting in average production of 6,346 Boe/d (79% oil and NGLs). Capital expenditures for 2014 are expected to total \$70 million, including the drilling of approximately 44 net wells. The Company operates, transports, and processes most of its production within the Redwater area.

Following the closing of the Deep Basin Acquisition on May 30, 2014, the Company has development and exploration assets located in the Wapiti and Pine Creek areas in western Alberta. The development focus is on Cardium liquids-rich natural gas and light oil. Production from the Deep Basin Acquisition assets averaged 6,000 Boe/d (28% oil and NGLs) in the month of June 2014, of which 5,200 Boe/d was located in the Deep Basin. Approximately 600 Boe/d of production from the acquired properties was curtailed in June due to third party plant restrictions and shut-downs. This unplanned shut down does not materially impact 2014 guidance. We will commence drilling in the Deep Basin area in the third quarter and expect to spend approximately \$40 million in the second half of 2014, including the drilling of approximately 11 net wells.

The Crocotta Acquisition will add approximately 7,500 Boe/d (30% oil and NGLs) of production in the Deep Basin area, as well as additional Cardium light oil and Bluesky natural gas locations. In addition, the acquisition adds significant ownership of operated gathering and processing infrastructure in the area, comprised of 50 MMcf/d of natural gas handling, oil batteries, pipeline gathering systems and an Alliance pipeline connection (meter station). The assets also include a working interest in the Edson natural gas plant and provide access to increased NGL value through existing marketing arrangements. This expanded facility and infrastructure maximizes operational efficiencies while reducing corporate reliance on third-party facilities and allows for significant visibility to the growth and expansion of Long Run's position in the Pine Creek area with no foreseeable infrastructure constraints.

Capital Investment

Capital Expenditures, Acquisitions & Dispositions

| (\$000s) | Q2 2014 | Q2 2013 | Six months ended June 30 | |
|----------------------------|----------|---------|--------------------------|---------|
| | | | 2014 | 2013 |
| Drilling and completion | 34,851 | 19,541 | 109,965 | 100,308 |
| Plant and facilities | 16,441 | 17,697 | 39,811 | 37,349 |
| Geological and geophysical | 4,295 | 779 | 5,234 | 2,093 |
| Other assets | 1,743 | 861 | 3,169 | 2,047 |
| Capital expenditures | 57,330 | 38,878 | 158,179 | 141,797 |
| Acquisitions – land | 3,493 | 970 | 4,694 | 11,087 |
| – properties | 230,117 | 20 | 233,678 | 13,869 |
| Dispositions | (19,894) | 168 | (28,336) | (5,853) |
| Net capital expenditures | 271,046 | 40,036 | 368,215 | 160,900 |

Drilling Activity

| | Q2 2014 Wells | | Q2 2013 Wells | | Success Rate (net wells) | |
|-------------|---------------|------|---------------|------|--------------------------|---------|
| | Gross | Net | Gross | Net | Q2 2014 | Q2 2013 |
| Peace River | 11.0 | 11.0 | 4.0 | 4.0 | 100% | 100% |
| Redwater | 11.0 | 11.0 | 8.0 | 8.0 | 100% | 100% |
| | 22.0 | 22.0 | 12.0 | 12.0 | 100% | 100% |

| | 2014 Wells | | 2013 Wells | | Success Rate (net wells) | |
|-------------|------------|------|------------|------|--------------------------|------|
| | Gross | Net | Gross | Net | 2014 | 2013 |
| Peace River | 31.0 | 30.5 | 23.0 | 23.0 | 100% | 96% |
| Redwater | 38.0 | 38.0 | 38.0 | 36.6 | 100% | 100% |
| Other | 1.0 | 1.0 | 4.0 | 4.0 | - | 50% |
| | 70.0 | 69.5 | 65.0 | 63.6 | 99% | 95% |

Capital Expenditures

Capital expenditures in the second quarter of 2014 were \$57.3 million. Capital spending is generally lower in the second quarter of the year due to access restrictions during spring break-up. Second quarter 2014 capital expenditures focused on oil development in the Peace River and Redwater areas. Of total capital expenditures, \$33.6 million (59%) was spent in Peace River and \$16.6 million (29%) was spent in Redwater. The Company drilled 22 (22.0 net) wells with a 100% success rate.

Capital expenditures in the second quarter of 2013 were \$38.9 million. Capital spending included a major facility turnaround at Kaybob, as well as drilling focused on development in the Peace River and Redwater areas. Of total capital expenditures, \$15.0 million (39%) was spent in Peace River and \$13.8 million (35%) was spent in Redwater. The Company drilled 12 (12.0 net) wells with a 100% success rate.

Capital expenditures in the first six months of 2014 were \$158.2 million, compared to \$141.8 million in the first six months of 2013. In 2014, capital expenditures were focused on oil development in the Peace River and Redwater areas. Of total capital expenditures, \$86.5 million (55%) was spent in Peace River and \$56.2 million (36%) was spent in Redwater. The Company drilled 70 (69.5 net) wells with a 99% success rate.

Capital expenditures in the first six months of 2013 were \$141.8 million, focused on drilling and completion activities in the Peace River and Redwater areas. Of total capital expenditures, \$64.7 million (46%) was spent in Peace River and \$51.6 million (36%) was spent in Redwater. The Company drilled 65 (63.6 net) wells with a 95% success rate.

Acquisitions and Dispositions

Acquisitions in the second quarter of 2014 were \$233.6 million, primarily consisting of the Deep Basin Acquisition for \$228.8 million, including purchase price adjustments. In the second quarter of 2014, the Company received \$19.9 million in disposition proceeds, of which \$12.0 million was received on the disposition of our heavy oil assets in the Lloydminster area and \$7.3 million was received on the disposal of an overriding royalty on a property in the Peace River area. The heavy oil assets in Lloydminster were producing approximately 400 Boe/d.

Acquisitions in the first six months of 2014 were \$238.4 million, primarily relating to the Deep Basin Acquisition discussed above and other minor property acquisitions. In the first six months of 2014 disposition proceeds of \$28.3 million included the items discussed above and \$8.4 million in proceeds primarily related to the disposition of a small property in the Peace River area which was producing approximately 250 Boe/d.

Acquisitions in the first six months of 2013 of \$25.0 million included an acquisition in the Redwater area for net costs of \$13.9 million and other minor property purchases.

Enhanced Oil Recovery

Enhanced Oil Recovery (“EOR”) projects initiated in the Peace River Montney developments at Normandville and Girouxville in 2013 have been operating successfully to date. We are on track to expand both of these EOR projects during the fourth quarter of 2014.

At Redwater, in the Viking, a second pilot EOR project is planned and will be implemented in the fourth quarter of 2014. This will complement the first EOR project, which was initiated during 2013, and will provide further technical data which will be used to evaluate field-wide EOR implementation, expected to start in 2015.

Production

Average Production by Product

| | Q2 2014 | Q2 2013 | Six months ended June 30 | |
|---------------------|---------|---------|--------------------------|--------|
| | | | 2014 | 2013 |
| Liquids (Bbl/d) | | | | |
| Light oil | 11,808 | 9,802 | 11,651 | 9,666 |
| Heavy oil | 668 | 1,669 | 929 | 1,625 |
| NGLs | 2,038 | 1,116 | 1,812 | 1,182 |
| Total | 14,514 | 12,587 | 14,392 | 12,473 |
| Natural Gas (Mcf/d) | 78,524 | 71,058 | 73,327 | 69,297 |
| Total (Boe/d) | 27,602 | 24,431 | 26,613 | 24,023 |

Average Production by Area

| | Q2 2014 | | | | Q2 2013 | | | |
|-------------|----------------|-----------------|---------------------------|------------------|----------------|-----------------|---------------------------|------------------|
| | 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 | 6,251 | 268 | 25,805 | 10,820 | 5,383 | 213 | 26,133 | 9,952 |
| Redwater | 5,092 | 101 | 8,367 | 6,588 | 4,147 | 48 | 7,494 | 5,444 |
| Deep Basin | 102 | 410 | 7,551 | 1,771 | - | - | - | - |
| Boyer | - | - | 18,272 | 3,045 | - | 2 | 19,633 | 3,274 |
| Kaybob | - | 981 | 5,569 | 1,909 | 17 | 638 | 4,626 | 1,426 |
| Other | 1,031 | 278 | 12,960 | 3,469 | 1,924 | 215 | 13,172 | 4,335 |
| | 12,476 | 2,038 | 78,524 | 27,602 | 11,471 | 1,116 | 71,058 | 24,431 |

| | Six months ended June 30, 2014 | | | | Six months ended June 30, 2013 | | | |
|-------------|--------------------------------|-----------------|---------------------------|------------------|--------------------------------|-----------------|---------------------------|------------------|
| | 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 | 6,282 | 262 | 25,106 | 10,728 | 5,350 | 214 | 24,838 | 9,704 |
| Redwater | 4,950 | 79 | 7,905 | 6,346 | 4,030 | 49 | 7,448 | 5,320 |
| Deep Basin | 51 | 206 | 3,797 | 890 | - | - | - | - |
| Boyer | - | - | 17,337 | 2,890 | - | 1 | 18,635 | 3,107 |
| Kaybob | - | 1,004 | 5,117 | 1,857 | 17 | 703 | 5,489 | 1,635 |
| Other | 1,297 | 261 | 14,065 | 3,902 | 1,894 | 215 | 12,887 | 4,257 |
| | 12,580 | 1,812 | 73,327 | 26,613 | 11,291 | 1,182 | 69,297 | 24,023 |

Production for the second quarter of 2014 averaged 27,602 Boe/d, a 13% increase from 24,431 Boe/d in 2013. Production for the first six months of 2014 averaged 26,613 Boe/d, an 11% increase from 24,023 Boe/d in 2013. The production increases reflect one month of production from the Deep Basin Acquisition, the results of our active drilling programs over the last year, as well as production added from strategic tuck-in acquisitions in late 2013.

Peace River production increased 9% to 10,820 Boe/d from 9,952 Boe/d in 2013, while Redwater production increased 21% to 6,588 Boe/d from 5,444 Boe/d. The Deep Basin Acquisition added 2,008 Boe/d of production in the quarter, with 200 Boe/d of production curtailed due to third party plant restrictions and shut-downs. The Deep Basin Acquisition production is included in the Deep Basin and Redwater areas.

Production at Boyer decreased 7% in 2014 compared to 2013, reflecting natural declines. Production at Kaybob was higher in 2014 compared to 2013 due to down-time in 2013 during a planned major facility turnaround.

Commodity Pricing

| | Q2 2014 | Q2 2013 | Six months ended June 30 | |
|-------------------------------|---------|---------|--------------------------|-------|
| | | | 2014 | 2013 |
| Benchmark pricing | | | | |
| WTI (\$/Bbl) | 102.98 | 94.20 | 100.81 | 94.28 |
| Edmonton Light Sweet (\$/Bbl) | 105.62 | 92.33 | 102.64 | 90.26 |
| AECO (\$/Mcf) | 4.69 | 3.53 | 5.17 | 3.36 |
| Cdn\$/US\$ exchange rate | 1.09 | 1.02 | 1.10 | 1.02 |
| Prices, excluding derivatives | | | | |
| Liquids (\$/Bbl) | | | | |
| Light oil | 97.50 | 83.70 | 94.43 | 80.27 |
| Heavy oil | 81.79 | 71.52 | 79.95 | 63.57 |
| Total Oil | 96.65 | 81.92 | 93.36 | 77.86 |
| NGLs | 72.76 | 68.91 | 78.89 | 72.28 |
| Total | 93.30 | 80.78 | 91.54 | 77.34 |
| Natural Gas (\$/Mcf) | 4.89 | 3.73 | 5.38 | 3.56 |
| Total (\$/Boe) | 63.17 | 52.72 | 64.47 | 50.79 |
| Prices, including derivatives | | | | |
| Liquids (\$/Bbl) | | | | |
| Oil | 89.59 | 81.80 | 87.73 | 77.39 |
| NGLs | 72.76 | 68.91 | 78.89 | 72.28 |
| Total | 87.23 | 80.67 | 86.62 | 76.91 |
| Natural Gas (\$/Mcf) | 4.61 | 3.89 | 5.03 | 3.76 |
| Total (\$/Boe) | 59.13 | 53.29 | 60.82 | 51.26 |

The Company's financial results are influenced by fluctuations in commodity prices and Canadian price differentials. Our average oil price for the second quarter of 2014 was \$96.65/Bbl, an increase of \$14.73/Bbl over 2013. Long Run's average oil price during the first six months of 2014 was \$93.36/Bbl, an increase of \$15.50/Bbl over 2013. The increased price in both periods reflects higher West Texas Intermediate benchmark pricing, a stronger U.S. dollar and narrower field differentials.

In the second quarter of 2014, Long Run's natural gas price was \$4.89/Mcf, an increase of \$1.16/Mcf over 2013. Our average natural gas price during the first six months of 2014 was \$5.38/Mcf, an increase of \$1.82/Mcf over 2013. The increased price in both periods reflects the strengthening of AECO benchmark pricing. AECO pricing was favorably influenced by the reduction in gas storage levels brought about by the cold winter experienced in North America. 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 from the volatility of commodity prices. During the second quarter of 2014, our oil price including derivative contracts was \$89.59/Bbl, including a realized loss of \$7.06/Bbl. The Company's natural gas price including derivatives of \$4.61/Mcf included a realized loss of \$0.28/Mcf. During the six months ended June 30, 2014, Long Run's oil price including derivative contracts of \$87.73/Bbl included a loss on derivative contracts of \$5.63/Bbl. The Company's natural gas price including derivatives of \$5.03/Mcf included a realized loss of \$0.35/Mcf.

Operating Results

Operating Netback & Funds Flow from Operations

| | Q2 2014 | | Q2 2013 | |
|---|----------|---------|----------|---------|
| | \$000s | \$/Boe | \$000s | \$/Boe |
| Revenues | 158,678 | 63.17 | 117,210 | 52.72 |
| Royalties | (17,598) | (7.01) | (9,753) | (4.38) |
| | 141,080 | 56.16 | 107,457 | 48.34 |
| Realized gain (loss) on derivatives | (10,157) | (4.04) | 1,285 | 0.57 |
| Transportation costs | (5,287) | (2.10) | (5,250) | (2.36) |
| Operating costs | (37,614) | (14.98) | (31,083) | (13.98) |
| Operating netback | 88,022 | 35.04 | 72,409 | 32.57 |
| General and administration | (9,134) | (3.64) | (5,493) | (2.47) |
| Interest | (5,507) | (2.19) | (3,634) | (1.63) |
| Exploration expenses | 48 | 0.02 | (36) | (0.02) |
| Capital and other taxes | - | - | (19) | (0.01) |
| Funds flow from operations ¹ | 73,429 | 29.23 | 63,227 | 28.44 |

¹ See Non-GAAP Measures section.

| | Six months ended June 30, | | | |
|---|---------------------------|---------|----------|---------|
| | 2014 | | 2013 | |
| | \$000s | \$/Boe | \$000s | \$/Boe |
| Revenues | 310,564 | 64.47 | 220,823 | 50.79 |
| Royalties | (36,064) | (7.49) | (21,543) | (4.96) |
| | 274,500 | 56.98 | 199,280 | 45.83 |
| Realized gain (loss) on derivatives | (17,579) | (3.65) | 2,041 | 0.47 |
| Transportation costs | (10,830) | (2.25) | (9,733) | (2.24) |
| Operating costs | (73,808) | (15.32) | (59,825) | (13.76) |
| Operating netback | 172,283 | 35.76 | 131,763 | 30.30 |
| General and administration | (17,863) | (3.71) | (12,954) | (2.98) |
| Interest | (10,423) | (2.16) | (6,857) | (1.57) |
| Exploration expenses | (518) | (0.11) | (36) | (0.01) |
| Capital and other taxes | - | - | (45) | (0.01) |
| Funds flow from operations ¹ | 143,479 | 29.78 | 111,871 | 25.73 |

¹ See Non-GAAP Measures section.

Second quarter 2014 compared to second quarter 2013

In the second quarter of 2014, funds flow from operations was \$73.4 million, an increase of \$10.2 million from the second quarter of 2013 due to the following:

- Higher liquids and natural gas production, attributable to successful drilling programs, the Deep Basin Acquisition, and properties acquired in late 2013, increased revenue by \$20.7 million; and
- Higher liquids and natural gas prices, excluding derivative contracts, increased revenue by \$20.8 million;

Partially offset by:

- Royalties associated with increased revenue were \$7.8 million higher, averaging 11.1% of revenue in 2014 compared to 8.3% in 2013. The increase reflects the impact of higher commodity prices, the higher liquids weighting and favorable gas cost allowance adjustments in 2013;
- A realized loss on financial derivative contracts of \$10.2 million compared to a realized gain of \$1.3 million in 2013. During 2014, we realized a loss on oil derivative contracts of \$8.0 million and a loss on natural gas derivative contracts of \$2.0 million due to higher benchmark pricing;
- Operating costs increased \$6.5 million resulting from higher production volumes. The increase per Boe reflects the higher liquids weighting. Our average cost per Boe is expected to decrease with a full period of production from the lower cost Deep Basin Acquisition properties and with the addition of the lower cost properties acquired in the Crocotta Acquisition. During June 2014, operating expenses for the Deep Basin Acquisition assets averaged \$7.50/Boe;
- General and administration costs increased \$3.6 million due to \$2.0 million of transaction costs associated with the Deep Basin Acquisition and higher employee costs. Excluding transaction costs, general and administration costs averaged \$2.85/Boe; and
- Interest expense increased \$1.9 million, attributable to a higher average debt balance outstanding primarily resulting from the Company's recent acquisitions.

Six months ended June 30, 2014 compared to six months ended June 30, 2013

In the first six months of 2014, funds flow from operations was \$143.5 million, an increase of \$31.6 million from the first six months of 2013 due to the following:

- Higher liquids and natural gas production increased revenue by \$38.8 million, attributable to successful drilling programs, the Deep Basin Acquisition and properties acquired during calendar 2013; and
- Higher liquids and natural gas prices, excluding derivative contracts, increased revenue by \$50.9 million;

Partially offset by:

- Royalties associated with increased revenue were \$14.5 million higher, averaging 11.6% of revenue in 2014 compared to 9.8% in 2013. The increase reflects the impact of higher commodity pricing, the higher liquids weighting and favorable gas cost allowance adjustments in 2013;
- A realized loss on financial derivative contracts of \$17.6 million compared to a realized gain of \$2.0 million in 2013. During 2014, realized a loss on oil derivative contracts of \$12.8 million and a loss on natural gas derivative contracts of \$4.6 million due to higher benchmark pricing;

- Operating costs increased \$14.0 million primarily resulting from the higher production volumes. The increase per Boe reflects the increase in the liquids weighting and the extremely cold weather experienced in Alberta in the first quarter of 2014, which increased fuel and power, labour, and well servicing costs. The Company's operating costs are expected to average \$13.50/Boe for 2014;
- General and administration costs increased \$4.9 million due to \$2.0 million of transaction costs associated with the Deep Basin Acquisition and higher employee costs. Excluding the transaction costs, general and administration costs averaged \$3.29/Boe. General and administration expenses are expected to average \$2.75/Boe for 2014, excluding transaction costs; and
- Interest expense increased \$3.6 million, attributable to a higher average debt outstanding primarily resulting from the Company's recent acquisitions.

Other Income & Expenses

| (\$000s) | Q2 2014 | Q2 2013 | Six months ended June 30 | |
|---|----------|----------|--------------------------|----------|
| | | | 2014 | 2013 |
| Unrealized gain (loss) on derivatives | 972 | 8,918 | (9,811) | (1,842) |
| Share-based compensation | (593) | (1,103) | (1,175) | (2,091) |
| Accretion | (2,659) | (1,575) | (4,781) | (3,033) |
| Depletion and depreciation | (50,460) | (40,265) | (100,123) | (77,724) |
| Gain (loss) on disposal of assets | 7,356 | (418) | 9,684 | 1,135 |
| Deferred income tax expense | (7,203) | (7,685) | (9,660) | (8,044) |
| Funds flow from operations ¹ | 73,429 | 63,227 | 143,479 | 111,871 |
| Net earnings (loss) | 20,842 | 21,099 | 27,613 | 20,272 |

¹ See Non-GAAP Measures section.

Second quarter 2014 compared to second quarter 2013

In comparing the second quarter of 2014 to the second quarter of 2013:

- The unrealized gain on financial derivatives of \$1.0 million decreased by \$7.9 million from 2013. The unrealized gain of \$1.0 million included a \$5.6 million gain on natural gas derivative contracts attributable to decreases in forward natural gas prices, partially offset by a \$4.7 million loss on crude oil derivative contracts reflecting increased forward oil prices.
- Depletion and depreciation expense of \$50.5 million increased \$10.1 million due to the increase in production volumes and the depletion rate. The depletion rate for 2014 was \$20.10/Boe compared to \$18.10/Boe in 2013. The 2014 rate reflects costs associated with the development of oil properties and the properties acquired in late 2013.
- The gain on disposal of assets of \$7.4 million compares to a loss of \$0.4 million in 2013. The gain in 2014 related primarily to the disposition of our heavy oil properties and an overriding royalty in our Peace River area.

Six months ended June 30, 2014 compared to six months ended June 30, 2013

In comparing the six months ended June 30, 2014 to the six months ended June 30, 2013:

- The unrealized loss on financial derivative contracts of \$9.8 million increased \$8.0 million from 2013. Unrealized losses of \$6.6 million on crude oil derivative contracts and \$3.4 million on natural gas derivative contracts were recorded in 2014, reflecting increases in forward commodity prices.
- Depletion and depreciation expense of \$100.1 million increased \$22.4 million due to the increase in production volumes and the depletion rate. The depletion rate for 2014 of \$20.80/Boe compared to \$17.90 /Boe in 2013. The 2014 rate reflects costs associated with the development of oil properties and the properties acquired in late 2013.
- The gain on disposal of assets of \$9.7 million increased by \$8.5 million from 2013. The gain in 2014 related to the disposition of our heavy oil properties at Lloydminster, an overriding royalty disposition in our Peace River area and a minor property.

In determining deferred income tax expense, the Company's effective tax rate differs from the Canadian statutory tax rate due to permanent differences that primarily arise due to share-based compensation costs. The Company's statutory tax rate is 25%.

Liquidity and Capital Resources

Net Debt

| (\$000s) | June 30, 2014 | December 31, 2013 |
|-------------------------------------|------------------|----------------------|
| Bank debt | 494,500 | 423,553 |
| Working capital deficiency | 24,585 | 28,602 |
| Convertible Debentures – face value | 75,000 | - |
| Net debt ¹ | 594,085 | 452,155 |

¹ See Non-GAAP Measures section.

The Company's net debt at June 30, 2014 increased \$141.9 million from December 31, 2013, primarily attributable to \$115.2 million of the Deep Basin Acquisition being funded with debt. In addition, planned capital expenditures (net of disposition proceeds) and dividend payments totaling \$170.2 million exceeded funds flow from operations of \$143.5 million during the period. Of the \$250 million in planned 2014 capital expenditures, \$158.2 million were incurred in the first six months. For 2014, we expect net capital expenditures (excluding the Deep Basin Acquisition and Crocotta Acquisition costs) and dividend payments to be funded using funds flow from operations.

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.

Credit Facilities

During the second quarter, the Company's credit facilities increased from \$475 million to \$575 million in connection with the Deep Basin Acquisition, and the termination date was extended to May 31, 2017. The credit facilities consisted of a \$545 million revolving syndicated facility and a \$30 million operating facility. Total borrowings permitted under these facilities cannot exceed the borrowing base, which is determined by the lenders on a semi-annual basis or upon the occurrence of a material event. At June 30, 2014, the Company had \$80.5 million of unused capacity on its credit facilities.

On August 6, 2014, the credit facilities borrowing base increased by \$120 million to \$695 million upon closing of the Crocotta Acquisition. The Crocotta Acquisition was funded from the issuance of approximately 44 million Long Run Common Shares and includes the assumption of approximately \$115 million in net debt.

Security for the credit facilities at June 30, 2014 included a demand debenture for \$1.0 billion which provides for a first ranking security interest and floating charge over all of the assets and property of the Company. On August 6, 2014, the demand debenture was increased to \$1.5 billion.

The credit facilities are subject to semi-annual review with the next review scheduled for November 2014. The Company has determined that as it does not intend to repay the facility within the next 12 months, the bank debt should be classified as long term on the statement of financial position. While the Company does not anticipate a reduction to the borrowing base below the level of bank debt currently outstanding, there is no assurance that the borrowing base will be maintained at current levels until May 31, 2017.

At June 30, 2014, the Company was in compliance with all covenants, obligations, and conditions of its credit agreement. The covenant requirements under the credit facilities have not changed since December 31, 2013. These covenants relate to bank debt and total debt to trailing 12 month EBITDA, interest coverage, permitted dispositions and permitted hedging. EBITDA is defined in the credit facilities as earnings before interest, exploration expenses, taxes, depletion and depreciation, and other non-cash items. The bank covenants require a senior debt to EBITDA ratio of less than 3:1 (June 30, 2014 – 1.8:1) and a total debt to EBITDA ratio of less than 3.5:1 (June 30, 2014 – 1.8:1). The interest coverage ratio, defined as EBITDA to interest expense, must be at least 3.5:1 (June 30, 2014 – 15.3:1). The convertible debentures issued in January 2014 are not considered debt for the debt to EBITDA ratio calculations under the credit agreement. Dispositions are permitted up to 10% of the borrowing base without formal approval of the lending syndicate. Commodity hedges are permitted on up to 75% of 2014 forecasted oil and natural gas production net of royalties (2015 - 75%; 2016 - 50%). Interest rate hedges are permitted up to 75% of the 2014 total debt balance (2015 - 75%; 2016 - 50%). 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 May 5, 2014 and June 6, 2014 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 29, 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. The increase in the Company's dividend rate associated with the closing of the Deep Basin Acquisition is not expected to adjust the convertible debentures conversion price in 2014.

Share Capital

| # of units (000s) | August 7, 2014 | June 30, 2014 | December 31, 2013 |
|--|----------------|---------------|-------------------|
| Common Shares | 149,626 | 149,596 | 110,143 |
| Non-Voting Convertible Shares ¹ | - | - | 15,513 |
| Options | 9,154 | 9,188 | 10,266 |
| Warrants | 2,300 | 2,300 | 2,300 |

¹ Each Non-Voting Convertible Share was convertible into one Common Share in certain events, including on transfer to a holder that would not be a Control Person (as defined in the share provisions thereof).

In connection with the Deep Basin Acquisition on April 30, 2014, Long Run closed the offering of 23.5 million subscription receipts ("Subscription Receipts") at a price of \$5.10 per Subscription Receipt, for gross proceeds of \$120.0 million. The Subscription Receipts were converted to Common Shares on May 30, 2014 upon closing of the Deep Basin Acquisition. The proceeds were used to fund a portion of the acquisition.

On May 21, 2014, Sprott Resource Corp. (“Sprott”) closed a secondary offering by Sprott of 12.7 million Long Run Common Shares on a bought deal basis at a price of \$5.35 per share. Long Run received no proceeds from this transaction and the total number of Long Run shares outstanding did not change. Upon completion of the secondary offering, Sprott converted their 15.5 million Long Run Non-Voting Convertible Shares into 15.5 million Long Run Common Shares. This also had no impact on the total number of Long Run shares outstanding or Long Run’s total shareholders’ equity.

In the first six months of 2014, there were 410,000 Long Run Common Shares issued on the exercise of stock options. The Company did not grant stock options in the first six months of 2014.

On August 6, 2014, upon closing of the Crocotta Acquisition, Long Run issued approximately 44 million Long Run Common Shares, based on an exchange ratio of 0.415 Long Run Common Shares for each of the 105.6 million Crocotta common shares outstanding.

The Company has 2.3 million warrants outstanding. Each warrant originally entitled the holder to acquire 0.4167 Long Run Common Shares at an exercise price of \$3.10 per 0.4167 of a share, until September 15, 2014. The exchange ratio and exercise price are subject to adjustment upon the payment of dividends by the Company and certain other events. At June 30, 2014, the warrants entitled the holder to acquire 0.4329 Long Run Common Shares at an exercise price of \$2.98 per 0.4329 of a share. The warrants are not exercisable until the twenty-day volume weighted average trading price of the Long Run Common Shares exceeds \$12.00 per share.

Dividends

In 2014 the Company transitioned its business model to a dividend plus growth model. Dividends are payable on Long Run Common Shares and Non-Voting Convertible Shares. Long Run initially established a monthly dividend to shareholders of \$0.0335 per share (\$0.402 per share annualized). Following the completion of the Deep Basin Acquisition, Long Run’s monthly dividend was increased to \$0.035 per share (\$0.42 per share annualized) effective for the June 2014 dividend, payable in July 2014. During the first six months of 2014, dividends of \$27.1 million (\$0.20 per share) have been declared. From July 1, 2014 to August 7, 2014, an additional \$5.2 million (\$0.035 per share) of dividends have been declared and will be paid on August 14, 2014.

Long Run’s dividend rate is subject to Board approval and will be reviewed regularly. Factors and conditions potentially impacting the monthly dividend rate include production volumes, current and future commodity prices, commodity hedging, foreign exchange rates, and acquisition opportunities.

Capital Structure

Long Run’s capital structure consists of debt plus equity. The Company’s primary capital management objective is to maintain a strong statement of financial position, which is expected to provide Long Run with financial flexibility and access to capital. This supports our objective of paying a monthly dividend while providing annual per share growth to shareholders.

The Company currently targets net debt to funds flow from operations at or below 1.5 times and debt to debt plus equity at or below 0.4 times. While the Company may exceed these ratios from time to time, efforts are made after a period of variation to bring the measures back in line. To manage the capital structure, the Company may adjust capital spending, adjust the dividend rate, issue equity, issue new debt or repay existing debt in response to changes in the business environment.

For the calculation of these metrics, see note 11 to the interim financial statements for three and six months ended June 30, 2014.

At June 30, 2014, net debt to funds flow from operations was 2.0 times, consistent with the ratio at December 31, 2013. Net debt at June 30, 2014 reflects a portion of the Deep Basin Acquisition funded with debt and the front end weighted 2014 capital development program. Funds flow for the second quarter includes only one month of financial results from the Deep Basin Acquisition assets acquired on May 30, 2014. Annualized funds flow used in the net debt to funds flow calculation included only four months of the acquisition's financial results. After giving effect to the Crocotta Acquisition, we expect to exit 2014 with net debt to funds flow from operations of approximately 1.75 times. In 2015, we will target to further reduce the ratio. At June 30, 2014, our debt to debt plus equity ratio was 0.4 times, in line with our target objective. This ratio is not expected to significantly change following the Crocotta Acquisition.

The Company believes that it has access to sufficient capital through operating activities, external debt and equity sources, and undrawn committed credit facilities to meet 2014 guidance on capital spending and dividend payments.

Contractual Obligations and Contingencies

Contractual Obligations

Commitments

| (\$000s) | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter | Total |
|-------------------------------------|--------------|---------------|---------------|----------------|---------------|----------------|----------------|
| Bank loan | - | - | - | 494,500 | - | - | 494,500 |
| Convertible debentures ¹ | - | - | - | - | - | 75,000 | 75,000 |
| Operating leases | 1,605 | 3,181 | 3,118 | 4,854 | 6,595 | 54,133 | 73,486 |
| Processing | - | 4,380 | 4,380 | 4,380 | 4,380 | 26,281 | 43,801 |
| Transportation | 2,377 | 5,462 | 4,634 | 3,826 | 2,279 | 2,940 | 21,518 |
| Fractionation | 1,282 | 2,224 | 1,228 | 268 | - | - | 5,002 |
| Capital | 3,542 | - | - | - | - | - | 3,542 |
| Total | 8,806 | 15,247 | 13,360 | 507,828 | 13,254 | 158,354 | 716,849 |

¹ Face value. Assumes the convertible debentures are not converted into Common Shares.

At June 30, 2014, the Company is committed under operating leases for office space, contracts related to the processing of natural gas, transportation of natural gas and NGLs, fractionation of natural gas liquids, and capital commitments for drilling rig services.

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. Exposure to these risks has not changed substantially since December 31, 2013.

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, 2013 and the Company's Annual Information Form for the year ended December 31, 2013.

Commodity Price

To partially mitigate exposure to commodity price risk, the Company enters into various financial derivative instruments. The Company has entered into crude oil and natural gas derivative contracts, including costless collars, fixed price, calls and call swaptions. As at June 30, 2014, the Company had contracts for crude oil volumes of 8,306 Bbl/d for the remainder of 2014 and 3,658 Bbl/d for 2015. As well, at June 30, 2014, the Company had average natural gas volumes of 49.3 MMcf/d contracted for the remainder of 2014 and 41.9 MMcf/d for 2015. Further details on the derivative contracts can be found in note 14 of the interim financial statements for the three and six months ended June 30, 2014.

In the first six months of 2014, the Company realized a \$17.6 million loss as a result of its commodity price risk management. The realized loss included a \$12.8 million loss on crude oil contracts and a \$4.6 million loss on natural gas financial derivative contracts. In the first six months of 2014, the Company recognized an unrealized loss on crude oil financial derivative contracts of \$6.6 million and an unrealized loss on natural gas financial derivative contracts of \$3.4 million. At June 30, 2014, the fair value of crude oil derivatives was a liability of \$23.7 million and the fair value of natural gas derivatives was a liability of \$3.9 million.

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, 2013.

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, 2013. There have been no significant changes to the accounting policies since December 31, 2013.

Adoption of New Accounting Policies

As required by IFRS, the Company adopted IFRIC 21 – *Levies* and the amendment to IAS 36 - *Impairment of Assets* as of January 1, 2014. The adoption of these policies did not have a material impact on the Company's financial results. Further details of these standards can be found in note 3 of the financial statements for the period ended June 30, 2014.

Future Accounting Pronouncements

As required by IFRS, the Company will be required to adopt the IFRS 11 – *Joint Arrangements* amendments on January 1, 2016 and IFRS 15 – *Contracts with Customers* on January 1, 2017. The Company has not yet determined the impact of adoption of these policies on the financial results. Further details of these standards can be found in note 3 of the financial statements for the period ended June 30, 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:

- In the second quarter of 2014, Long Run completed the Deep Basin Acquisition on May 30, 2014 for total consideration of \$228.8 million. Production averaged 2,008 Boe/d during the second quarter of 2014.
- In the fourth quarter of 2013, Long Run completed two significant light oil acquisitions in the Peace River and Redwater areas for total consideration of approximately \$95 million, with combined production of approximately 1,800 Boe/d (70% oil and NGLs) at the closing dates.
- In the third quarter of 2012, the Company completed a plan of arrangement to acquire Guide Exploration Ltd. ("Guide"). Funds flow from operations and net earnings prior to October 23, 2012 do not include the results of operations from the Guide properties.

| | 2014 | | 2013 | | | | 2012 | |
|--|---------|---------|---------|--------|--------|---------|-----------|---------|
| | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 |
| Funds flow from operations¹ (\$000s) | 73,429 | 70,050 | 55,934 | 62,304 | 63,227 | 48,644 | 38,407 | 26,546 |
| Per share, basic ¹ | 0.55 | 0.56 | 0.45 | 0.50 | 0.50 | 0.39 | 0.33 | 0.32 |
| Per share, diluted ¹ | 0.54 | 0.56 | 0.44 | 0.50 | 0.50 | 0.39 | 0.33 | 0.32 |
| Net earnings (loss) (\$000s) | 20,842 | 6,771 | (5,531) | 9,524 | 21,099 | (827) | (56,590) | (4,747) |
| Per share, basic | 0.16 | 0.05 | (0.04) | 0.08 | 0.17 | (0.01) | (0.49) | (0.06) |
| Per share, diluted | 0.15 | 0.05 | (0.04) | 0.08 | 0.17 | (0.01) | (0.49) | (0.06) |
| Dividend (\$000s) | 14,468 | 12,639 | - | - | - | - | - | - |
| Per share | 0.10 | 0.10 | - | - | - | - | - | - |
| Payout ratio ¹ | 20% | 18% | - | - | - | - | - | - |
| Capital (\$000s) | | | | | | | | |
| Drilling and completion | 34,851 | 75,114 | 30,750 | 72,746 | 19,541 | 80,767 | 46,623 | 18,957 |
| Plant and facilities | 16,441 | 23,370 | 8,760 | 18,699 | 17,697 | 19,652 | 10,590 | 9,149 |
| Geological and geophysical | 4,295 | 939 | 566 | 601 | 779 | 1,314 | 772 | 1,007 |
| Other assets | 1,743 | 1,425 | 1,561 | 1,091 | 861 | 1,186 | 355 | 79 |
| Capital expenditures | 57,330 | 100,848 | 41,637 | 93,137 | 38,878 | 102,919 | 58,340 | 29,192 |
| Net acquisitions (dispositions) | 213,716 | (3,679) | 86,328 | 3,331 | 1,158 | 17,945 | (169,731) | (138) |
| Capital investment | 271,046 | 97,169 | 127,965 | 96,468 | 40,036 | 120,864 | (111,391) | 29,054 |
| Wells drilled (net) | | | | | | | | |
| Peace | 11.0 | 19.5 | 9.5 | 19.5 | 4.0 | 19.0 | 5.0 | - |
| Redwater | 11.0 | 27.0 | 1.0 | 26.6 | 8.0 | 28.6 | 12.0 | 4.0 |
| Other | - | 1.0 | 1.0 | 4.0 | - | 4.0 | - | 3.0 |
| | 22.0 | 47.5 | 11.5 | 50.1 | 12.0 | 51.6 | 17.0 | 7.0 |
| Plato – disposed 2012 | - | - | - | - | - | - | 9.5 | 14.0 |
| Total | 22.0 | 47.5 | 11.5 | 50.1 | 12.0 | 51.6 | 26.5 | 21.0 |
| Production | | | | | | | | |
| Liquids (Bbl/d) | | | | | | | | |
| Light oil | 11,808 | 11,491 | 11,811 | 10,322 | 9,802 | 9,528 | 9,125 | 6,057 |
| Heavy oil | 668 | 1,193 | 1,440 | 1,387 | 1,669 | 1,581 | 1,538 | 1,128 |
| NGLs | 2,038 | 1,584 | 1,520 | 1,478 | 1,116 | 1,249 | 1,332 | 669 |
| | 14,514 | 14,268 | 14,771 | 13,187 | 12,587 | 12,358 | 11,995 | 7,854 |
| Natural Gas (Mcf/d) | 78,524 | 68,071 | 73,392 | 72,634 | 71,058 | 67,516 | 56,453 | 18,214 |
| Total (Boe/d) | 27,602 | 25,613 | 27,003 | 25,293 | 24,431 | 23,611 | 21,405 | 10,890 |
| Production by area (Boe/d) | | | | | | | | |
| Peace River | 10,820 | 10,637 | 11,500 | 10,101 | 9,952 | 9,453 | 6,691 | - |
| Redwater | 6,588 | 6,101 | 6,285 | 5,875 | 5,444 | 5,195 | 5,050 | 6,023 |
| Deep Basin | 1,771 | - | - | - | - | - | - | - |
| Boyer | 3,045 | 2,732 | 2,861 | 3,241 | 3,274 | 2,938 | 2,220 | - |
| Kaybob | 1,909 | 1,804 | 1,851 | 1,923 | 1,426 | 1,847 | 2,118 | 2,044 |
| Other | 3,469 | 4,339 | 4,506 | 4,153 | 4,335 | 4,178 | 3,615 | 1,182 |
| | 27,602 | 25,613 | 27,003 | 25,293 | 24,431 | 23,611 | 19,694 | 9,249 |
| Plato – disposed 2012 | - | - | - | - | - | - | 1,711 | 1,641 |
| Total | 27,602 | 25,613 | 27,003 | 25,293 | 24,431 | 23,611 | 21,405 | 10,890 |

| | 2014 | | 2013 | | | | 2012 | |
|--|----------|----------|----------|----------|----------|----------|----------|----------|
| | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 |
| Benchmark pricing | | | | | | | | |
| WTI (\$US/Bbl) | 102.98 | 98.68 | 97.46 | 105.83 | 94.20 | 94.37 | 88.18 | 92.22 |
| Edmonton Light Sweet (\$CAD/Bbl) | 105.62 | 99.83 | 86.58 | 104.98 | 92.33 | 88.19 | 83.99 | 84.33 |
| AECO (\$/Mcf) | 4.69 | 5.72 | 3.53 | 2.43 | 3.53 | 3.20 | 3.21 | 2.29 |
| Cdn\$/US\$ exchange rate | 1.09 | 1.10 | 1.05 | 1.04 | 1.02 | 1.01 | 0.99 | 1.00 |
| Prices, excluding derivatives | | | | | | | | |
| Liquids (\$/Bbl) | | | | | | | | |
| Light oil | 97.50 | 91.24 | 75.06 | 95.47 | 83.70 | 76.69 | 76.24 | 80.28 |
| Heavy oil | 81.79 | 78.90 | 62.69 | 87.40 | 71.52 | 55.10 | 57.89 | 59.77 |
| NGLs | 72.76 | 86.87 | 69.21 | 76.05 | 68.91 | 75.33 | 67.08 | 62.24 |
| Total | 93.30 | 89.72 | 73.25 | 92.44 | 80.78 | 73.79 | 72.87 | 75.78 |
| Natural Gas (\$/Mcf) | 4.89 | 5.96 | 3.73 | 2.65 | 3.73 | 3.37 | 3.35 | 2.44 |
| Total (\$/Boe) | 63.17 | 65.89 | 50.24 | 55.84 | 52.72 | 48.76 | 50.27 | 59.98 |
| Prices, including derivatives | | | | | | | | |
| Oil (\$/Bbl) | 89.59 | 85.89 | 71.14 | 87.44 | 81.80 | 72.77 | 76.54 | 79.14 |
| NGLs (\$/Bbl) | 72.76 | 86.87 | 69.21 | 76.05 | 68.91 | 75.33 | 67.08 | 62.24 |
| Natural Gas (\$/Mcf) | 4.61 | 5.53 | 4.04 | 3.23 | 3.89 | 3.63 | 4.19 | 2.44 |
| Total (\$/Boe) | 59.13 | 62.67 | 49.78 | 54.29 | 53.29 | 49.12 | 53.99 | 61.34 |
| Netback (\$/Boe) | | | | | | | | |
| Revenues | 63.17 | 65.89 | 50.24 | 55.84 | 52.72 | 48.76 | 50.27 | 59.98 |
| Royalties | (7.01) | (8.01) | (7.33) | (6.61) | (4.38) | (5.55) | (6.36) | (5.87) |
| Realized gain (loss) on derivatives | (4.04) | (3.22) | (0.46) | (1.54) | 0.57 | 0.36 | 3.72 | 1.36 |
| Transportation costs | (2.10) | (2.41) | (2.00) | (2.50) | (2.36) | (2.11) | (2.27) | (2.04) |
| Operating costs | (14.98) | (15.70) | (13.36) | (14.45) | (13.98) | (13.53) | (11.78) | (18.20) |
| Operating Netback | 35.04 | 36.55 | 27.09 | 30.74 | 32.57 | 27.93 | 33.58 | 35.23 |
| G&A | (3.64) | (3.79) | (2.82) | (2.31) | (2.47) | (3.51) | (11.86) | (6.68) |
| Interest | (2.19) | (2.13) | (1.73) | (1.56) | (1.63) | (1.52) | (1.96) | (1.84) |
| Corporate Netback | 29.21 | 30.63 | 22.54 | 26.87 | 28.47 | 22.90 | 19.76 | 26.71 |
| Funds flow from operations¹ (\$000s) | | | | | | | | |
| Revenues | 158,678 | 151,886 | 124,816 | 129,923 | 117,210 | 103,613 | 99,000 | 60,094 |
| Royalties | (17,598) | (18,466) | (18,213) | (15,377) | (9,753) | (11,790) | (12,521) | (5,882) |
| Realized gain (loss) on derivatives | (10,157) | (7,422) | (1,145) | (3,585) | 1,285 | 756 | 7,320 | 1,362 |
| Transportation costs | (5,287) | (5,543) | (4,971) | (5,816) | (5,250) | (4,483) | (4,474) | (2,048) |
| Operating costs | (37,614) | (36,194) | (33,198) | (33,614) | (31,083) | (28,742) | (23,195) | (18,238) |
| | 88,022 | 84,261 | 67,289 | 71,531 | 72,409 | 59,354 | 66,130 | 35,288 |
| G&A | (9,134) | (8,729) | (7,017) | (5,378) | (5,493) | (7,461) | (23,351) | (6,696) |
| Interest | (5,507) | (4,916) | (4,300) | (3,633) | (3,634) | (3,223) | (3,864) | (1,844) |
| Other | 48 | (566) | (38) | (216) | (55) | (26) | (508) | (202) |
| | 73,429 | 70,050 | 55,934 | 62,304 | 63,227 | 48,644 | 38,407 | 26,546 |

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, net debt and payout ratio. 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

| (\$000s) | 2014 | | 2013 | | | | 2012 | |
|---|---------|---------|----------|---------|---------|---------|---------|---------|
| | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 |
| Cash flow from operating activities | 67,280 | 59,781 | 65,932 | 61,756 | 60,835 | 45,733 | 43,325 | 31,417 |
| Change in non-cash working capital | 5,452 | 8,923 | (11,758) | (266) | 1,958 | 1,949 | (5,722) | (4,871) |
| Abandonment costs | 697 | 1,346 | 1,760 | 814 | 434 | 962 | 804 | - |
| Funds flow from operations | 73,429 | 70,050 | 55,934 | 62,304 | 63,227 | 48,644 | 38,407 | 26,546 |
| Weighted average outstanding shares (000s) | | | | | | | | |
| - Basic | 134,291 | 125,730 | 125,629 | 125,620 | 125,620 | 125,620 | 115,421 | 82,969 |
| - Diluted | 135,437 | 126,129 | 126,245 | 125,620 | 125,620 | 125,620 | 115,421 | 83,016 |
| Funds flow from operations per share (\$/share) | | | | | | | | |
| - Basic | 0.55 | 0.56 | 0.45 | 0.50 | 0.50 | 0.39 | 0.33 | 0.32 |
| - Diluted | 0.54 | 0.56 | 0.44 | 0.50 | 0.50 | 0.39 | 0.33 | 0.32 |

| (\$000s) | Six months ended June 30 | |
|---|--------------------------|---------|
| | 2014 | 2013 |
| Cash flow from operating activities | 127,061 | 106,568 |
| Change in non-cash working capital | 14,375 | 3,907 |
| Abandonment costs | 2,043 | 1,396 |
| Funds flow from operations | 143,479 | 111,871 |
| Weighted average outstanding shares (000s) | | |
| - Basic | 130,035 | 125,620 |
| - Diluted | 130,916 | 125,620 |
| Funds flow from operations per share (\$/share) | | |
| - Basic | 1.10 | 0.89 |
| - Diluted | 1.10 | 0.89 |

Net Debt

| (\$000s) | June 30, 2014 | December 31, 2013 |
|--|------------------|----------------------|
| Bank debt | 494,500 | 423,553 |
| Working capital deficiency | | |
| Accounts payable and accrued liabilities | 107,396 | 89,606 |
| Accounts receivable | (71,012) | (53,433) |
| Prepaid expenses and deposits | (11,799) | (7,571) |
| Convertible debentures – face value | 75,000 | - |
| Net Debt | 594,085 | 452,155 |

Payout Ratio

Payout ratio is defined as dividends declared divided by funds flow from operations.

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 expected effects of the Crocotta Acquisition, Crocotta net debt to be assumed, anticipated 2014 operating and general and administrative costs and expected decrease in operating costs per BOE, 2014 average production, commodity mix, capital expenditures, dividends and dividends per share, exit net debt to funds flow from operations ratio, our capital expenditure program, nature of expenditures and method of funding capital expenditures and dividends, drilling and development plans and the timing thereof, sources of funding, timing of new wells being brought on production, and timing of field implementation of EOR and timing of second pilot EOR at Redwater and effect thereof, expectation that unused credit facilities will be sufficient to satisfy working capital deficiencies and that the Company has sufficient capital to meet guidance of capital expenditures and dividends, timing of review date of borrowing base under credit facilities and anticipation that it will not be reduced, expectation that the increase in dividends will not adjust the conversion rate of convertible debentures in 2014, timing of next dividend payment and expected effect of the Crocotta Acquisition on debt to debt plus equity ratio. 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 Long Run's ability to integrate the assets acquired pursuant to the Deep Basin Acquisition and the Crocotta Acquisition and the effects thereof. Included herein are estimates of Long Run's 2014 exit net debt to funds flow from operations ratio based on assumptions provided herein and other assumptions utilized in arriving at Long Run's capital budget. To the extent such estimates constitute a financial outlook, they were approved by management on June 12, 2014 and are included herein to provide readers with an understanding of the effects of the Crocotta Acquisition and anticipated funds available to Long Run to fund its capital expenditures, dividends and the effects thereof on debt levels 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. The payment of a dividend by the Company is subject to declaration thereof by the board of directors and continuation of the dividend policy will be subject to and dependent on the Company's cash flow and other expenditures, including capital expenditures. 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

Petroleum 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 crude 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 and dividing by total production. Corporate netback per Boe is calculated as operating netback less interest and general and administration costs and divided by total production.

Abbreviations

Oil and Natural Gas Liquids

| | |
|---------|-----------------------------------|
| MBbl | thousand barrels |
| MMBbl | million barrels |
| Bbl/d | barrels per day |
| NGL | natural gas liquids |
| Boe | 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.