# Q3 2016

Freehold
ROYALTIES LTD.

## THIRD QUARTER REPORT

NINE MONTHS, ENDING SEPTEMBER 30, 2016

## Results at a Glance

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| **FINANCIAL** ($000s, except as noted) | **2016** | 2015 | Change | **2016** | 2015 | Change |
| Gross revenue | **32,923** | 36,076 | -9% | **90,075** | 101,831 | -12% |
| Net income (loss) (1) | **(1,962)** | (22,193) | -91% | **(12,801)** | 3,343 | -483% |
| Per share, basic and diluted ($) | **(0.02)** | (0.23) | -91% | **(0.12)** | 0.04 | -400% |
| Funds from operations (1) | **24,148** | 27,643 | -13% | **63,790** | 78,311 | -19% |
| Per share, basic ($) | **0.21** | 0.28 | -25% | **0.59** | 0.89 | -34% |
| Operating income (2) | **28,231** | 30,601 | -8% | **76,534** | 85,966 | -11% |
| Operating income from royalties (%) | **93** | 90 | 3% | **93** | 86 | 8% |
| Acquisitions | **68** | 815 | -92% | **162,498** | 411,495 | -61% |
| Capital expenditures | **209** | 7,969 | -97% | **3,046** | 16,688 | -82% |
| Dividends declared | **14,133** | 24,604 | -43% | **45,358** | 69,392 | -35% |
| Per share ($) (3) | **0.12** | 0.25 | -52% | **0.42** | 0.79 | -47% |
| Net debt obligations (2) | **87,301** | 148,994 | -41% | **87,301** | 148,994 | -41% |
| Shares outstanding, period end (000s) | **117,850** | 98,599 | 20% | **117,850** | 98,599 | 20% |
| Average shares outstanding (000s) (4) | **117,726** | 98,357 | 20% | **107,888** | 87,733 | 23% |
| **OPERATING** | | | | | | |
| Average daily production (boe/d) (5) | **12,281** | 11,266 | 9% | **12,099** | 10,652 | 14% |
| Oil and NGL (%) | **55** | 63 | -13% | **59** | 61 | -3% |
| Average price realizations ($/boe) (5) | **28.69** | 34.11 | -16% | **26.50** | 34.27 | -23% |
| Operating netback ($/boe) (2) (5) | **24.99** | 29.52 | -15% | **23.09** | 29.57 | -22% |

(1) For the three and nine months ended September 30, 2016, net loss and funds from operations include a $1.1 million loss upon settlement of litigation.
(2) See Non-GAAP Financial Measures.
(3) Based on the number of shares issued and outstanding at each record date.
(4) Weighted average number of shares outstanding during the period, basic.
(5) See Conversion of Natural Gas to Barrels of Oil Equivalent (boe).

# MANAGEMENT'S DISCUSSION AND ANALYSIS

*The following Management's Discussion and Analysis (MD&A) was prepared as of November 8, 2016, and is management's opinion about the consolidated operating and financial results of Freehold Royalties Ltd. and its wholly-owned subsidiaries (collectively, Freehold) for the three and nine months ended September 30, 2016, and previous periods, and the outlook for Freehold based on information available as of November 8, 2016.*

The financial information contained herein is based on information in the interim condensed consolidated financial statements prepared in accordance with International Financial Reporting Standards (IFRS), which are the Canadian generally accepted accounting principles (GAAP) for publicly accountable enterprises. All comparative percentages are between the three and nine months ended September 30, 2016 and September 30, 2015, and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion should be read in conjunction with Freehold's annual MD&A and audited financial statements for the year ended December 31, 2015, together with the accompanying notes. Information contained in the 2015 annual MD&A that is not discussed in this document remains materially unchanged.

This MD&A contains non-GAAP financial measures and forward-looking statements that are intended to help readers better understand our business and prospects. Readers are cautioned that the MD&A should be read in conjunction with our disclosure under "Non-GAAP Financial Measures" and "Forward-Looking Statements" included at the end of this MD&A.

## 2016 Third Quarter Highlights

- Freehold's production averaged a record 12,281 boe/d, a 9% improvement over Q3-2015 and 2% increase over Q2-2016. Gains in production were largely driven by better than expected third party production additions and a full quarter's production from our Q2-2016 acquisition from certain affiliates of Husky Energy Inc. (the Husky Transaction).
- Royalty production was up 16% compared to Q3-2015, averaging 10,169 boe/d, accounting for 83% of production and 93% of operating income.
- Funds from operations totaled $24.1 million ($0.21 per share) in Q3-2016, flat over the previous quarter but down 13% from last year with reduced commodity prices somewhat offset by higher production. Impacting funds from operations Freehold settled an outstanding legal claim recognizing a loss of $1.1 million.
- Freehold generated $9.8 million in free cash flow(1) over and above our dividend, which we applied to outstanding debt. At September 30, 2016, net debt obligations(1) totaled $87.3 million, down $10.9 million from $98.2 million at June 30, 2016. This implies a net debt to 12-month trailing funds from operations ratio of 1.0 times. Despite challenging commodity prices, we continue to generate an attractive netback and free cash flow.
- Cash costs(1) for the quarter totaled $6.78/boe, down from $7.34/boe in Q2-2016 and $8.84/boe in Q3-2015. Included in these costs General and Administrative (G&A) costs totalled $1.71/boe for Q3-2016 versus $2.04/boe in Q2-2016 and $2.33/boe in Q3-2015.

- Wells drilled on our royalty lands totaled 48 (2.3 equivalent net) in the quarter; for the first three quarters of 2016, 156 (6.1 equivalent net) wells were drilled, including 15 royalty wells on the recently acquired acreage associated with the Husky Transaction, with seven locations targeting the Shaunavon.
- In Q3-2016, Freehold issued four leases; 71 leases have been issued in the first three quarters of 2016, 57 relating to the Q2-2016 Husky Transaction.
- Dividends declared for Q3-2016 totaled $0.12 per share, unchanged from the previous quarter and down from $0.25 per share one year ago.
- Basic payout ratio(1) (dividends declared/funds from operations) for Q3-2016 totaled 59% while the adjusted payout ratio(1) (cash dividends plus capital expenditures/funds from operations) for the same period was 55%.

(1) See Non-GAAP Financial Measures.

# Business Overview

Freehold is a dividend-paying corporation incorporated under the laws of the Province of Alberta and trades on the Toronto Stock Exchange under the symbol FRU. Freehold is directly and indirectly involved in the development and production of oil and natural gas, predominantly in western Canada. We receive revenue from oil and natural gas properties as reserves are produced over the economic life of the properties. Our primary focus is acquiring and managing oil and natural gas royalties.

## The Royalty Advantage

We manage one of the largest non-government portfolios of oil and natural gas royalties in Canada. Our total land holdings encompass approximately 6.2 million gross acres, greater than 95% of which are royalties. Of this, our mineral title lands (including royalty assumption lands), which we own in perpetuity, cover approximately 1.0 million acres. In addition, we have gross overriding royalty interests in over 4.9 million acres.

We have interests in more than 42,000 wells (of which over 40,000 are royalty wells including over 20,000 unitized wells). We receive royalty income from over 300 industry operators. Royalty rates vary from less than 1.0% (for some gross overriding royalties) to 22.5% (for some lessor royalties). This diversity lowers our risk, while we benefit from the drilling activity of other operators on our lands.

As a royalty interest owner, we generally do not pay any of the capital costs to drill and equip the wells for production on most of our properties, nor do we incur costs to operate the wells, maintain production, and ultimately restore the land to its original state. Generally all of these costs are paid by others. On the majority of our production, we receive royalty income from gross production revenue (revenue before any royalty expenses and operating costs are deducted). Our high percentage of operating income from royalties (93% in Q3-2016) results in strong netbacks.

When Freehold was formed in 1996, all of our royalty lands were leased to third parties and producing. Over the years, our unleased mineral title acreage has grown – through acquisitions, lease expiries, surrenders, and defaults. We now have approximately 380,000 unleased mineral title acres.

## Our Strategy

We effectively manage and grow our assets to consistently deliver attractive returns to shareholders over the long term. Our vision is to be recognized as a leading royalty focused oil and gas corporation in Canada. We employ the following strategies in order to achieve this goal:

- Acquire appropriate assets with a focus on royalty interests, to provide long-term growth in value. The key criteria are:
  - quality assets;
  - attractive returns;
  - acceptable risk profile; and
  - long economic life.
- Maintain an aggressive audit program.
- Optimize assets and production.
- Manage debt prudently.
- Deliver long-term dividend sustainability.

# Outlook

## Business Environment

After a volatile Q2-2016 where prices were impacted by supply disruptions in Canada (forest fires) and Nigeria (political unrest), Q3-2016 was a relatively uneventful period for prices, with no major supply or demand issues having a material impact on prices in either direction. For the quarter, West Texas Intermediate (WTI) prices averaged U.S.$44.94/bbl, down 3% when compared to the same period last year and down 1% when compared to the previous quarter. Western Canada Select (WCS) prices averaged $41.02/bbl, down 5% versus last year and also down 1% quarter over quarter.

Key macro drivers of crude oil prices over the quarter included resiliency in U.S. production primarily stemming from Permian development. Within Canada, we continue to see producers allocate capital to higher netback plays such as the Montney, Viking and Bakken. However conventional volumes continue to trend down with a price improvement from current levels likely needed to incentivize producers to materially expand their capital spending budgets. Globally, there remains considerable volatility associated with the future direction of OPEC, with the market waiting on a firm output decision when the group meets again at the end of November. We continue to maintain a modestly bullish view on prices, but although the movement in WTI from U.S.$30.00 to $50.00/bbl was relatively swift, a move from U.S.$50.00 to $70.00/bbl is expected to be more prolonged and difficult.

On the natural gas side, AECO prices (30-day firm contract) averaged $2.20/mcf in Q3-2016, down 21% from the same period last year but up 76% when compared to Q2-2016. The rise in natural gas prices can be attributed to record high pipeline exports to Mexico and improving industrial demand coupled with a drop in gas rig counts and associated growth, all of which generated a draw down in inventories. For Western Canadian gas, and AECO in particular, the ramping up of oil sands production and associated gas demand after the wild fires, along with completion of pipeline maintenance, helped improve pricing.

Overall, we see natural gas fundamentals continuing to be challenged by growing supplies within North America despite prices improving quarter over quarter. U.S. natural gas production remains resilient with shale plays such as the Marcellus and Utica displaying material growth.

## Industry Activity

In November 2016, the Petroleum Services Association of Canada (PSAC) updated its 2017 drilling forecast. The group is currently projecting 4,175 wells drilled through 2017, representing an increase of 225 wells and an approximate 6% increase from the latest 2016 forecast. PSAC based its 2017 forecast on average natural gas prices of $2.50/mcf AECO, WTI prices of U.S.$52.00/bbl and $0.76 Canadian/U.S. exchange rate.

**ROYALTY INTEREST DRILLING**

| | Three Months Ended September 30 (1) | | | | Nine Months Ended September 30 (1) | | | |
|---|---|---|---|---|---|---|---|---|
| | **2016** | | 2015 | | **2016** | | 2015 | |
| | | **Equivalent** | | Equivalent | | **Equivalent** | | Equivalent |
| | **Gross** | **Net (2)** | Gross | Net (2) | **Gross** | **Net (2)** | Gross | Net (2) |
| Non-unitized wells | **46** | **2.3** | 98 | 8.9 | **105** | **5.8** | 194 | 14.7 |
| Unitized wells (3) | **2** | **-** | 11 | 0.1 | **51** | **0.3** | 98 | 0.6 |
| Total | **48** | **2.3** | 109 | 9.0 | **156** | **6.1** | 292 | 15.3 |
| Royalty joint venture (4) | **-** | | - | | **-** | | 4 | |

(1) Counts include wells drilled on acquired lands from January 1st (this may differ from the closing date of the acquisitions).
(2) Equivalent net wells are the aggregate of the numbers obtained by multiplying each gross well by our royalty interest percentage.
(3) Unitized wells are in production units wherein we generally have small royalty interests in hundreds of wells.
(4) Wells drilled on various royalty joint venture lands, where equivalent net wells cannot be calculated.

Including drilling associated with acquisitions, 156 (6.1 equivalent net) wells were drilled on our royalty lands through the first three quarters of 2016, which represents a 60% decrease on a net measure versus the same period in 2015. Our royalty lands give us exposure to some of the most economic resource plays currently being pursued in the Western Canadian Sedimentary Basin. Through 2016 drilling totals have been impacted by the absence of activity within our Dodsland Viking area through the first half of the year. With the change of the operator in this area, we have seen activity levels pick up with 11 Viking wells drilled by various operators and a further 50 Viking locations licensed in inventory. In the Williston Basin, 20 locations were drilled by various operators primarily targeting the Mississippian carbonates, and locations were also drilled in the Watrous, Bakken, and Torquay. On the recently acquired acreage from the Husky Transaction, 15 wells were drilled with seven locations targeting the Shaunavon, and a further four heavy oil locations. A further five Shaunavon drilling licenses remain in inventory.

## 2016 Guidance Update

The table below summarizes our key operating assumptions for 2016, updated to reflect actual statistics for the first nine months and our current expectations for the remainder of the year.

- We have increased our production guidance from 11,700 boe/d to 12,000 boe/d, reflecting better than expected production additions on our royalty lands. Volumes are expected to be weighted approximately 58% oil and natural gas liquids (NGL) and 42% natural gas. We continue to maintain our royalty focus with royalty production accounting for 81% of forecasted 2016 production and 94% of operating income.
- We have increased our WTI and WCS price assumptions from $40.00/bbl and $34.00/bbl to $43.00/bbl and $38.00/bbl respectively.
- We have revised upward our 2016 AECO natural gas price assumption from $2.00/mcf to $2.10/mcf.
- We have revised our G&A expense assumption from $2.40/boe to $2.35/boe reflecting the increased production guidance.
- Our capital spending budget has been reduced from $7 million to $6 million. A large percentage of our capital expenditure program is non-operated and the activity level is difficult to predict.
- We expect our 2016 basic payout ratio to be approximately 65% (previously 74%), as a result of the increase in 2016 forecast commodity prices.
- We forecast year-end net debt to funds from operations of approximately 0.8 times based on our revised key operating assumptions (excluding the proforma effects of acquisitions).

### KEY OPERATING ASSUMPTIONS

| 2016 Annual Average | | Nov. 8, 2016 | Aug. 4, 2016 | May 11, 2016 | Mar. 3, 2016 | Nov. 12, 2015 |
|---|---|---|---|---|---|---|
| Daily production | boe/d | 12,000 | 11,700 | 11,400 | 9,800 | 9,800 |
| WTI oil price | US$/bbl | 43.00 | 40.00 | 40.00 | 35.00 | 50.00 |
| Western Canadian Select (WCS) | Cdn$/bbl | 38.00 | 34.00 | 34.00 | 31.00 | 47.00 |
| AECO natural gas price | Cdn$/Mcf | 2.10 | 2.00 | 1.80 | 2.00 | 2.75 |
| Exchange rate | Cdn$/US$ | 0.76 | 0.76 | 0.77 | 0.72 | 0.76 |
| Operating costs | $/boe | 3.75 | 3.75 | 4.00 | 4.75 | 5.00 |
| General and administrative costs (1) | $/boe | 2.35 | 2.40 | 2.50 | 2.65 | 2.85 |
| Capital expenditures | $ millions | 6 | 7 | 7 | 7 | 15 |
| Dividends paid in shares (DRIP) (2) | $ millions | 5 | 5 | 8 | 8 | 13 |
| Weighted average shares outstanding | millions | 110 | 110 | 109 | 100 | 100 |

(1) Excludes share based and other compensation.

(2) Effective with the August 2016 dividend the Board approved the suspension of the DRIP pending further notice.

## 2017 Outlook

We see average production volumes of 11,000 boe/d (assuming no acquisitions), which includes expectations of 100 boe/d of shut-in working interest natural gas, 100 boe/d of shut-in heavy oil production (primarily working interest) and production additions associated with our strong audit function. Estimated volumes are comprised of approximately 56% oil and NGL and 44% natural gas. We continue to maintain our royalty focus with royalty production expected to account for approximately 84% of production and 91% of operating income.

### KEY OPERATING ASSUMPTIONS

| 2017 Annual Average | | Nov. 8, 2016 |
|---|---|---|
| Daily production | boe/d | 11,000 |
| WTI oil price | US$/bbl | 50.00 |
| Western Canadian Select (WCS) | Cdn$/bbl | 46.00 |
| AECO natural gas price | Cdn$/Mcf | 3.00 |
| Exchange rate | Cdn$/US$ | 0.75 |
| Operating costs | $/boe | 3.25 |
| General and administrative costs (1) | $/boe | 2.65 |
| Capital expenditures | $ millions | 6 |
| Weighted average shares outstanding | millions | 118 |

(1) Excludes share based and other compensation.

Recognizing the cyclical nature of the oil and gas industry, we continue to closely monitor commodity prices and industry trends for signs of changing market conditions. We caution that it is inherently difficult to predict activity levels on our royalty lands since we have no operational control. As well, significant changes (positive or negative) in commodity prices (including Canadian oil price differentials), foreign exchange rates, or production rates may result in adjustments to the dividend rate.

Based on our current guidance and commodity price assumptions, and assuming no significant changes in the current business environment, we expect to maintain the monthly dividend rate through the next quarter. We will continue to evaluate the commodity price environment and adjust the dividend levels as necessary (subject to the quarterly review and approval of our Board of Directors - see Dividend Policy).

## Quarterly Performance and Seasonality

Quarterly variances in revenues, net income (loss) and funds from operations are caused mainly by fluctuations in commodity prices and production volumes. Crude oil prices are generally determined by global supply and demand factors, and the variances do not have seasonable predictability. Natural gas is a typically seasonal, weather-dependent fuel; demand is generally higher during the winter (for heating) and summer (for cooling), and lower during the spring and fall. Over most of the past eight quarters, this seasonality has been muted by ample supply. Natural gas prices are affected by weather conditions, industrial demand, and North American natural gas inventories.

Our financial results over the last eight quarters were influenced by the following significant changes:

- The decision by OPEC in late 2014 to keep production at existing levels resulted in a material retreat in worldwide crude oil prices with prices remaining weak through 2015 and the first nine months of 2016.
- Fluctuations in foreign exchange rates affected our oil price realizations, resulting in positive impacts on our Canadian dollar oil revenues relative to the benchmark WTI, which is referenced in U.S. dollars.
- AECO prices continue to be impacted by supply outstripping demand. Strong gains in North American natural gas supply associated with horizontal drilling within shale gas plays has resulted in increased production deliverability.
- The largest effect on our dividends is from funds from operations, which is mainly a function of revenues and cash expenses. The collapse in oil prices in late 2014 continuing through the first nine months of 2016 resulted in changes to our monthly dividend from $0.14 to $0.09 in Q1-2015 from $0.09 to $0.07 in Q3-2015 and from $0.07 to $0.04 in Q1-2016.
- Production has been affected by drilling activity and acquisitions, as well as a number of one-time adjustments. We use government reporting databases and past production receipts to estimate revenue accruals. Due to the large number of wells in which we have royalty interests, the nature of royalty interests, the lag in receiving production receipts from the operators, and our audit program, our reported royalty volumes usually include both positive and negative adjustments related to prior periods.
- Over the past eight quarters, we have acquired approximately $635 million of mainly royalty assets in Alberta and Saskatchewan. This activity affects our revenues, percentage royalty interests, oil/gas production split and debt levels, among others.

The accompanying table illustrates the fluctuations experienced over the past eight quarters and the resulting effect on our financial results. Additional information about our quarterly results is provided in our interim reports, copies of which are available on SEDAR and on our website.

## QUARTERLY REVIEW

| | 2016 | | | 2015 | | | | 2014 |
|---|---|---|---|---|---|---|---|---|
| | **Q3** | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 | Q4 |
| **Financial** ($000s, except as noted) | | | | | | | | |
| Revenue, net of royalty expense | **32,639** | 31,903 | 24,670 | 33,728 | 35,391 | 37,222 | 27,026 | 42,597 |
| Funds from operations (1) | **24,148** | 24,142 | 15,500 | 25,509 | 27,643 | 28,730 | 21,938 | 30,774 |
| Per share, basic ($) | **0.21** | 0.23 | 0.16 | 0.26 | 0.28 | 0.32 | 0.29 | 0.41 |
| Net income (loss) (1) | **(1,962)** | (2,249) | (8,590) | (7,423) | (22,193) | 3,919 | 21,617 | 11,082 |
| Per share, basic and diluted ($) | **(0.02)** | (0.02) | (0.09) | (0.08) | (0.23) | 0.04 | 0.29 | 0.15 |
| Dividends declared | **14,133** | 13,380 | 17,845 | 20,747 | 24,604 | 24,459 | 20,329 | 31,353 |
| Per share ($) (2) | **0.12** | 0.12 | 0.18 | 0.21 | 0.25 | 0.27 | 0.27 | 0.42 |
| Basic payout ratio (%) (3) | **59** | 55 | 115 | 81 | 89 | 85 | 93 | 102 |
| Operating Income (3) | **28,231** | 28,011 | 20,292 | 29,186 | 30,601 | 32,733 | 22,632 | 37,584 |
| Operating income from royalties (%) | **93** | 91 | 97 | 89 | 90 | 85 | 83 | 80 |
| Dividends paid in shares (DRIP) | **1,170** | 1,443 | 2,384 | 2,758 | 3,708 | 2,398 | 8,361 | 10,915 |
| Average DRIP participation rate (%) (4) | **8** | 11 | 11 | 13 | 14 | 11 | 35 | 35 |
| Acquisitions | **68** | 162,211 | 219 | (143) | 815 | 342,310 | 68,370 | 60,566 |
| Capital expenditures | **209** | 753 | 2,084 | 5,607 | 7,969 | 2,750 | 5,969 | 13,500 |
| Net debt obligations (3) | **87,301** | 98,191 | 149,197 | 146,949 | 148,994 | 146,992 | 198,834 | 135,810 |
| **Shares outstanding** | | | | | | | | |
| Weighted average, basic (000s) | **117,726** | 106,736 | 99,093 | 98,731 | 98,357 | 89,388 | 75,199 | 74,545 |
| At quarter end (000s) | **117,850** | 117,652 | 99,284 | 98,940 | 98,599 | 98,203 | 75,457 | 74,919 |
| **Operating** ($/boe, except as noted) | | | | | | | | |
| Daily production (boe/d) (5) | **12,281** | 12,041 | 11,974 | 11,815 | 11,266 | 10,617 | 10,058 | 9,836 |
| Royalty interest (%) | **83** | 81 | 79 | 78 | 78 | 76 | 71 | 74 |
| Average selling price | **28.69** | 28.48 | 22.23 | 30.34 | 34.11 | 38.63 | 29.80 | 47.46 |
| Operating netback (3) | **24.99** | 25.57 | 18.62 | 26.85 | 29.52 | 33.88 | 25.01 | 41.54 |
| Operating expenses | **3.90** | 3.55 | 4.02 | 4.18 | 4.62 | 4.65 | 4.85 | 5.54 |
| Working interest properties | **22.69** | 18.47 | 19.41 | 19.24 | 20.78 | 19.14 | 16.87 | 21.66 |
| General and administrative expenses (6) | **1.71** | 2.04 | 3.05 | 2.23 | 2.33 | 2.34 | 3.92 | 2.32 |
| **Benchmark Prices** | | | | | | | | |
| WTI crude oil (US$/bbl) | **44.94** | 45.59 | 33.45 | 42.18 | 46.43 | 57.94 | 48.64 | 73.15 |
| Exchange rate (US$/Cdn$) | **0.77** | 0.78 | 0.73 | 0.75 | 0.76 | 0.81 | 0.81 | 0.88 |
| Edmonton Par crude oil (Cdn$/bbl) | **54.85** | 54.70 | 40.84 | 52.89 | 56.23 | 67.75 | 51.95 | 75.79 |
| Western Canadian Select (WCS) (Cdn$/bbl) | **41.02** | 41.62 | 26.32 | 36.86 | 43.29 | 56.97 | 42.14 | 66.74 |
| AECO natural gas (Cdn$/Mcf) | **2.20** | 1.25 | 2.11 | 2.65 | 2.80 | 2.67 | 2.95 | 4.01 |
| **Share Trading Performance** | | | | | | | | |
| High ($) | **13.09** | 13.00 | 12.05 | 13.52 | 16.07 | 19.04 | 20.62 | 23.27 |
| Low ($) | **10.61** | 9.66 | 8.29 | 9.00 | 8.73 | 15.86 | 16.14 | 17.02 |
| Close ($) | **12.65** | 11.91 | 10.54 | 10.86 | 10.82 | 16.14 | 17.94 | 19.12 |
| Volume (000s) | **20,873** | 23,559 | 19,690 | 19,312 | 22,753 | 18,912 | 14,297 | 18,607 |

(1) For the three months ended September 30, 2016, net loss and funds from operations include a $1.1 million loss upon settlement of litigation.
(2) Based on the number of shares issued and outstanding at each record date.
(3) See Non-GAAP Financial Measures
(4) The DRIP was suspended effective with the August 2016 dividend, pending further notice.
(5) Reported production for a period may include adjustments from previous production periods.
(6) Excludes share based and other compensation.

**AVERAGE DAILY PRODUCTION**

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2016** | 2015 | Change | **2016** | 2015 | Change |
| **Royalty interest** [1] | | | | | | |
| Oil (bbls/d) | **4,753** | 4,926 | -4% | **4,998** | 4,205 | 19% |
| NGL (bbls/d) | **596** | 356 | 67% | **579** | 396 | 46% |
| Natural gas (Mcf/d) | **28,921** | 20,874 | 39% | **25,319** | 20,357 | 24% |
| Oil equivalent (boe/d) | **10,169** | 8,761 | 16% | **9,797** | 7,994 | 23% |
| **Working interest** [1] | | | | | | |
| Oil (bbls/d) | **1,259** | 1,661 | -24% | **1,385** | 1,738 | -20% |
| NGL (bbls/d) | **187** | 140 | 34% | **195** | 150 | 30% |
| Natural gas (Mcf/d) | **3,993** | 4,226 | -6% | **4,330** | 4,620 | -6% |
| Oil equivalent (boe/d) | **2,112** | 2,505 | -16% | **2,302** | 2,658 | -13% |
| **Total** | | | | | | |
| Oil (bbls/d) | **6,012** | 6,587 | -9% | **6,383** | 5,943 | 7% |
| NGL (bbls/d) | **783** | 496 | 58% | **774** | 546 | 42% |
| Natural gas (Mcf/d) | **32,914** | 25,100 | 31% | **29,649** | 24,977 | 19% |
| Oil equivalent (boe/d) | **12,281** | 11,266 | 9% | **12,099** | 10,652 | 14% |
| Number of days in period (days) | **92** | 92 | 0% | **274** | 273 | 0% |
| Total volumes during period (Mboe) | **1,130** | 1,037 | 9% | **3,315** | 2,908 | 14% |

(1) On certain properties where we have both a royalty interest and a working interest, production is allocated based on the applicable royalty and working interest percentages.

Our production mix through the first nine months of 2016 was 41% natural gas, 35% light and medium oil, 18% heavy oil and 6% NGL. In 2016 the natural gas component has become slightly higher with the Q2-2016 Husky Transaction. Over the past three years, the composition of our liquids volumes have become lighter, driven by acquisitions which added royalty assets in southeast Saskatchewan and the Dodsland area of southwest Saskatchewan.

Compared to the same period in 2015, oil and NGL production decreased 4% in the third quarter, while natural gas production rose 31%. The overall gain in production is largely attributed to the Q2-2016 Husky Transaction. Over the quarter, there were also positive prior period adjustments of approximately 60 boe/d, the majority resulting from our strong audit function, including compensatory royalties realized on our mineral title lands (Q3-2015 prior period positive adjustments were 350 boe/d).

Working interest production decreased 16% versus Q3-2015 as we continue to deemphasize development within this weaker price environment as our royalty portfolio generates superior netbacks.

## Marketing and Hedging

Our royalty lands consist of a large number of properties with generally small volumes per property. Many of our agreements allow us to take our production in-kind. As part of our risk mitigation program we carefully monitor our royalty receivables and may choose to take our royalty in-kind if there are benefits in doing so. Currently we take in-kind and market approximately 20% of our total royalty production using 30-day contracts.

We market most of our working interest oil production using 30-day contracts to ensure competitive pricing. Currently approximately 60% of our working interest natural gas production is being sold under marketing arrangements tied to the Alberta monthly or daily spot price (AECO) or other indexed reference price, the balance being marketed with the operators' production.

To date we have not hedged any of our production. Hedging is monitored on an ongoing basis and is reviewed quarterly with the Board.

### AVERAGE BENCHMARK PRICES

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2016** | 2015 | Change | **2016** | 2015 | Change |
| WTI crude oil (US$/bbl) | **44.94** | 46.43 | -3% | **41.33** | 51.00 | -19% |
| Exchange rate (US$/Cdn$) | **0.77** | 0.76 | 1% | **0.76** | 0.79 | -4% |
| Edmonton Par crude oil (Cdn$/bbl) | **54.85** | 56.23 | -2% | **50.13** | 58.64 | -15% |
| Western Canadian Select (WCS) (Cdn$/bbl) | **41.02** | 43.29 | -5% | **36.32** | 47.46 | -23% |
| WTI/Edmonton Par differential ($/bbl) | **9.91** | 9.80 | 1% | **8.80** | 7.64 | 15% |
| Edmonton Par/WCS differential (Cdn$/bbl) | **(13.83)** | (12.94) | 7% | **(13.81)** | (11.18) | 24% |
| AECO natural gas (Cdn$/Mcf) | **2.20** | 2.80 | -21% | **1.85** | 2.80 | -34% |

Crude oil prices in Q3-2016 were down slightly year over year with continuing weak supply/demand fundamentals. WTI was down 3% versus last year and WCS down 5%. AECO natural gas in Q3-2016 was down 21% versus the same period last year as natural gas fundamentals continue to be challenged by growing supplies within North America.

The price we receive for our production is primarily driven by the U.S. dollar price of WTI, adjusted to western Canada. Therefore, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenue received. The Canadian currency was 1% higher than in Q3-2015 which further mitigated our revenues coupled with the drop in WTI.

### AVERAGE SELLING PRICES

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2016** | 2015 | Change | **2016** | 2015 | Change |
| Oil ($/bbl) | **44.57** | 46.52 | -4% | **39.81** | 49.03 | -19% |
| NGL ($/bbl) | **24.95** | 29.73 | -16% | **26.27** | 28.15 | -7% |
| Oil and NGL ($/bbl) | **42.31** | 45.35 | -7% | **38.35** | 47.28 | -19% |
| Natural gas ($/Mcf) | **1.97** | 2.51 | -22% | **1.56** | 2.33 | -33% |
| Oil equivalent ($/boe) | **28.69** | 34.11 | -16% | **26.50** | 34.27 | -23% |

As the key driver behind a reduction in overall cash flows, liquids pricing in Q3-2016 was down versus the same period last year with our average realized oil and NGL price declining by 7%. Our average selling prices reflect production, quality and transportation differences from benchmark prices. Our oil and NGL price currently is at an approximate $2.00 premium to WCS, however the current quarter is lower due to prior period adjustments.

Similar to oil, natural gas prices trended down over the quarter, decreasing 22% from the same period last year. Our natural gas price realizations are discounted compared to AECO pricing as they include transportation and processing fees netted from some natural gas royalty payments.

# Revenue

Gross revenue decreased 9% in Q3-2016 versus the same period last year due to lower commodity prices, partly offset by an increase in production.

### GROSS REVENUE BY PRODUCT

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| ($000s) | **2016** | 2015 | Change | **2016** | 2015 | Change |
| **Royalty interest revenue** | | | | | | |
| Oil | **19,241** | 21,039 | -9% | **54,339** | 56,244 | -3% |
| NGL | **1,455** | 1,153 | 26% | **4,663** | 3,431 | 36% |
| Natural gas | **5,135** | 4,715 | 9% | **10,619** | 12,651 | -16% |
| Other [(1)] | **354** | 554 | -36% | **1,905** | 1,723 | 11% |
| | **26,185** | 27,461 | -5% | **71,526** | 74,049 | -3% |
| **Working interest revenue** | | | | | | |
| Oil | **5,408** | 7,156 | -24% | **15,289** | 23,306 | -34% |
| NGL | **343** | 205 | 67% | **910** | 767 | 19% |
| Natural gas | **829** | 1,088 | -24% | **2,026** | 3,252 | -38% |
| Other [(1)] | **158** | 166 | -5% | **324** | 457 | -29% |
| | **6,738** | 8,615 | -22% | **18,549** | 27,782 | -33% |
| **Total gross revenue** | | | | | | |
| Oil | **24,649** | 28,195 | -13% | **69,628** | 79,550 | -12% |
| NGL | **1,798** | 1,358 | 32% | **5,573** | 4,198 | 33% |
| Natural gas | **5,964** | 5,803 | 3% | **12,645** | 15,903 | -20% |
| Other [(1)] | **512** | 720 | -29% | **2,229** | 2,180 | 2% |
| | **32,923** | 36,076 | -9% | **90,075** | 101,831 | -12% |

(1) Other includes potash, sulphur, lease rentals, and other revenue for royalty interest, and processing fees, interest and other revenue for working interest.

The following table demonstrates the effect of price and volume variances on gross revenues. In Q3-2016 our volumes for gas increased but lower oil and NGL volumes and weakness in commodity prices drove underperformance relative to Q3-2015.

### GROSS REVENUE VARIANCES

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| ($000s) | **2016 vs. 2015** | 2015 vs. 2014 | **2016 vs. 2015** | 2015 vs. 2014 |
| **Oil and NGL** | | | | |
| Production increase (decrease) | **(1,123)** | 5,080 | **7,274** | 10,168 |
| Price decrease | **(1,983)** | (19,830) | **(15,821)** | (58,742) |
| Net decrease | **(3,106)** | (14,750) | **(8,547)** | (48,574) |
| **Natural gas** | | | | |
| Production increase | **1,415** | 858 | **2,036** | 3,462 |
| Price decrease | **(1,254)** | (2,407) | **(5,294)** | (9,636) |
| Net increase (decrease) | **161** | (1,549) | **(3,258)** | (6,174) |
| **Other [(1)]** | **(208)** | 32 | **49** | 360 |
| Gross revenue decrease | **(3,153)** | (16,267) | **(11,756)** | (54,388) |

(1) Other revenue includes potash, sulphur, lease rentals, processing fees, interest and other.

### NET REVENUE

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| ($000s) | **2016** | 2015 | Change | **2016** | 2015 | Change |
| Gross revenue | **32,923** | 36,076 | -9% | **90,075** | 101,831 | -12% |
| Royalty expense (1) | **(284)** | (685) | -59% | **(863)** | (2,192) | -61% |
| Net revenue | **32,639** | 35,391 | -8% | **89,212** | 99,639 | -10% |

(1) Royalty expense includes both Crown charges and royalty payments to third parties.

# Expenses

### ROYALTY EXPENSE (1)

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| ($000s, except as noted) | **2016** | 2015 | Change | **2016** | 2015 | Change |
| Working interest | **278** | 680 | -59% | **774** | 2,005 | -61% |
| Per boe ($) | **1.43** | 2.95 | -52% | **1.23** | 2.76 | -55% |
| Royalty interest (2) | **6** | 5 | 20% | **89** | 187 | -52% |
| Per boe ($) | **0.01** | 0.01 | 0% | **0.03** | 0.09 | -67% |
| Total | **284** | 685 | -59% | **863** | 2,192 | -61% |
| Per boe ($) | **0.25** | 0.66 | -62% | **0.26** | 0.75 | -65% |

(1) Royalty expense includes both Crown charges and royalty payments to third parties.
(2) Comprised of freehold mineral tax.

Oil and gas producers pay royalties to the owners of mineral rights from whom they have acquired leases. These are paid to the Crown (provincial and federal governments) and freehold mineral title owners. Crown royalty rates are tied to commodity prices and the level of oil and gas sales.

At a corporate level, royalty charges were down 62% on a boe basis in Q3-2016 versus the same period in 2015 due to the retreat in pricing and lower working interest production. We do not incur Crown or third party royalty expenses on production from our royalty interest properties (currently 83% of total production) other than minor freehold mineral taxes. As the royalty owner, we receive the royalty as income from other companies.

### OPERATING EXPENSES

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| ($000s, except as noted) | **2016** | 2015 | Change | **2016** | 2015 | Change |
| Working interest | **4,408** | 4,790 | -8% | **12,678** | 13,673 | -7% |
| Per boe ($) | **22.69** | 20.78 | 9% | **20.11** | 18.84 | 7% |
| Royalty interest (1) | **-** | - | - | **-** | - | - |
| Per boe ($) | **-** | - | - | **-** | - | - |
| Total operating expenses | **4,408** | 4,790 | -8% | **12,678** | 13,673 | -7% |
| Total ($/boe) | **3.90** | 4.62 | -16% | **3.82** | 4.70 | -19% |

(1) We do not incur operating expenses on production from our royalty lands.

On certain properties where we have both a royalty interest and a working interest, production is allocated based on the royalty/working interest percentages. However, all of the operating costs relating to that production have been allocated to the working interest properties. Freehold does not operate the majority of its working interest properties and as a result has limited control over expenses.

On a total boe basis Q3-2016 operating costs averaged $3.90/boe, a 16% decrease from the same period in 2015, reflecting increased royalty production as a percentage of total production. The operating costs within our working interest properties were up 9% per boe versus the previous year reflecting prior period charges that flowed through on some non-operated properties.

## Netback Analysis

As a royalty owner, we share in production revenue without incurring the operational costs, risks, and responsibilities typically associated with oil and natural gas operations. The table below demonstrates the advantage of our royalty lands, which have no operating or royalty expenses (other than minor freehold mineral taxes). Royalty interests accounted for 79% of gross revenue through the first nine months and more importantly contributed 93% of operating income.

### OPERATING INCOME (1)

| | Nine months ended September 30, 2016 | | |
|---|---|---|---|
| ($000s) | Royalty Interest | Working Interest | **Total** |
| Gross revenue (2) | 71,526 | 18,549 | **90,075** |
| Royalty expense (3) | (89) | (774) | **(863)** |
| Net revenue | 71,437 | 17,775 | **89,212** |
| Operating expense | - | (12,678) | **(12,678)** |
| Operating income | 71,437 | 5,097 | **76,534** |
| Percentage by category | 93% | 7% | **100%** |

(1) See Non-GAAP Financial Measures.
(2) Gross revenue includes potash, sulphur, lease rentals, processing fees, interest and other.
(3) Royalty expense includes both Crown charges and royalty payments to third parties.

### OPERATING NETBACK

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| ($/boe) | **2016** | 2015 | Change | **2016** | 2015 | Change |
| Gross revenue (1) | **29.14** | 34.80 | -16% | **27.17** | 35.02 | -22% |
| Royalty expense (2) | **(0.25)** | (0.66) | -62% | **(0.26)** | (0.75) | -65% |
| Operating expenses | **(3.90)** | (4.62) | -16% | **(3.82)** | (4.70) | -19% |
| Operating netback (3) | **24.99** | 29.52 | -15% | **23.09** | 29.57 | -22% |

(1) Gross revenue includes potash, sulphur, lease rentals, processing fees, interest and other.
(2) Royalty expense includes both Crown charges and royalty payments to third parties.
(3) Operating netback is calculated by subtracting royalty and operating expenses from gross revenue. See Non-GAAP Financial Measures.

Freehold’s operating netback decreased 15% versus Q3-2015 mainly as a result of lower commodity prices. Also contributing to the decrease is our higher percentage of gas volumes due to the Q2-2016 Husky Transaction, with gas currently receiving lower pricing on a boe basis. Offsetting the decrease, Freehold is benefitting from lower costs, as our increasing royalty production as a percentage of total production is reducing royalty expense and operating expense on a boe basis.

## GENERAL AND ADMINISTRATIVE EXPENSES

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| ($000s, except as noted) | 2016 | 2015 | Change | 2016 | 2015 | Change |
| General and administrative expenses, before capitalized and overhead recoveries | 2,225 | 2,793 | -20% | 8,667 | 9,514 | -9% |
| Less: capitalized and overhead recoveries | (298) | (375) | -21% | (1,183) | (1,291) | -8% |
| General and administrative expenses | 1,927 | 2,418 | -20% | 7,484 | 8,223 | -9% |
| Per boe ($) | 1.71 | 2.33 | -27% | 2.26 | 2.83 | -20% |

We have significant land administration, accounting and auditing requirements to administer our royalty lands and collect royalty payments, including integrating acquisitions. General and administrative (G&A) expenses include direct costs and reimbursement of G&A expenses incurred by Rife Resources Management Ltd. (Manager) on behalf of Freehold (see Related Party Transactions). In Q3-2016 G&A charges were down 20% versus the same period in 2015. On a boe basis costs were down 27% to $1.71/boe largely a result of the production volumes we added through the Q2-2016 Husky Transaction and cost reduction initiatives. G&A expenses on a year-to-date boe basis are typically higher in the first quarter and decline through the remainder of the year as a number of annual expenses occur in the first quarter.

## MANAGEMENT FEES (PAID IN SHARES)

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | Change | 2016 | 2015 | Change |
| Shares issued for management fees | 71,912 | 71,912 | 0% | 215,736 | 198,066 | 9% |
| Ascribed value ($000s) (1) | 910 | 778 | 17% | 2,524 | 2,912 | -13% |
| Per boe ($) | 0.81 | 0.75 | 8% | 0.76 | 1.00 | -24% |

(1) The ascribed value of the management fees is based on the closing share price at the end of each quarter.

The Manager (see Related Party Transactions) receives a management fee in shares. In accordance with the previous amended and restated management agreement, the issue of shares from treasury related to equity offerings, resulted in pro-rata increases in the number of shares issued as the management fee (see Shareholders' Capital). The agreement was amended in November 2015 and as a result the management fee has been capped at 71,912 shares per quarter for 2016 and will be reduced to a level of 5,500 shares per quarter over the next seven years.

## SHARE BASED AND OTHER COMPENSATION

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| ($000s, except as noted) | 2016 | 2015 | Change | 2016 | 2015 | Change |
| Gross LTIP | 227 | (52) | -537% | 612 | 24 | 2450% |
| Less: capitalized portion | (42) | 8 | -625% | (111) | (5) | 2120% |
| Net LTIP | 185 | (44) | -520% | 501 | 19 | 2537% |
| Deferred share unit plan | (11) | 46 | -124% | 454 | 668 | -32% |
| Retirement benefit | - | 3 | -100% | 5 | 9 | -44% |
| Share based and other compensation | 174 | 5 | 3380% | 960 | 696 | 38% |
| Per boe ($) | 0.15 | - | - | 0.29 | 0.24 | 21% |

We are responsible for funding a portion of the long-term incentive compensation plan (the LTIP) for employees of the Manager. The 2013 LTIP grants valued at $0.1 million were paid out in 2016. The increase in LTIP expense in Q3-2016 is largely a result of the increase in share price quarter over quarter with share price having the largest effect on the valuation.

Pursuant to our deferred share unit plan, fully-vested deferred share units (DSUs) are granted annually in the first quarter to non-management directors and are redeemable for an equal number of shares (less tax withholdings if necessary) after the director's retirement. In 2016 the Board granted 41,437 DSUs to eligible directors in the first quarter and 5,226 DSUs in the second quarter (none in the third quarter). As at September 30, 2016, there were 167,097 DSUs outstanding, and as at November 8, 2016, there were 167,606 DSUs outstanding (including notional DSUs granted as a result of dividends paid on our common shares).

## Related Party Transactions

Freehold does not have any employees. Rife Resources Management Ltd. (the Manager) is the manager of Freehold. The Manager is a wholly-owned subsidiary of Rife Resources Ltd. (Rife), and two of Rife's directors are also directors of Freehold. Rife is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of the Canadian National Railway Company), which in turn is a shareholder of Freehold. The Manager recovers its general and administrative costs and a portion of its long-term incentive plan costs and retirement benefit costs, and receives a quarterly management fee paid in shares. Canpar Holdings Ltd. (Canpar) is also managed by Rife and owned 100% by the CN Pension Trust Funds, and two of Canpar's directors are also directors of Freehold.

**(a) Rife Resources Management Ltd.**

The Manager provides certain services for a fee based on a specified number of shares per quarter, pursuant to the amended and restated management agreement. The amended and restated management agreement caps the management fee at 71,912 shares per quarter for 2016 and the number of shares to be issued per quarter as payment of the management fee decreases to a level of 5,500 shares per quarter by 2023. For the three months ended September 30, 2016, Freehold issued 71,912 shares (2015 – 71,912) as payment of the management fee to the Manager pursuant to the management agreement. For the three months ended September 30, 2016, the ascribed value of $0.9 million (2015 – $0.8 million) was based on the closing price of the shares on the last trading day of each quarter. The total number of shares issued for the nine months ended September 30, 2016 was 215,736 (2015 – 198,066) with an ascribed value of $2.5 million (2015 – $2.9 million).

For the three months ended September 30, 2016, the Manager charged $1.8 million in general and administrative costs (2015 – $1.9 million). For the nine months ended September 30, 2016, the Manager charged $6.8 million in general and administrative costs (2015 – $7.0 million). At September 30, 2016, there was $0.6 million (December 31, 2015 – $0.7 million) in accounts payable and accrued liabilities relating to these costs.

**(b) Rife Resources Ltd.**

Freehold maintains ownership interests in certain oil and gas properties operated by Rife. A portion of net operating revenues and capital expenditures represent joint operations amounts from Rife. At September 30, 2016, there was $0.1 million (December 31, 2015 - $nil) in accounts receivable relating to these transactions. At September 30, 2016, there was $nil (December 31, 2015 - $nil) in accounts payable and accrued liabilities relating to these transactions.

In addition, Freehold receives royalties from Rife pursuant to various royalty agreements. For the three months ended September 30, 2016, Freehold received royalties of approximately $0.2 million (2015 – $0.4 million). For the nine months ended September 30, 2016, Freehold received royalties of approximately $0.6 million (2015 – $1.2 million). At September 30, 2016, there was $0.1 million (December 31, 2015 - $0.1 million) in accounts receivable relating to these transactions.

(c) Canpar Holdings Ltd.

Freehold and Canpar share mineral title ownership rights in a substantial land base in western Canada. Generally, Canpar owns mineral rights that were below the deepest producing formation at the time that Freehold was created, and Freehold holds the balance of the mineral rights. Given the nature of the mineral rights, which are dependent upon hydrocarbon pool formation classification as well as third party drilling data which is subject to change and revision, significant uncertainty can exist with respect to the royalty ownership of wells drilled and completed on lands where both Freehold and Canpar hold the mineral rights.

During and prior to 2015, Freehold and Canpar evaluated certain of these royalty interests where, among other factors, the identification of the reservoir formation was not straight forward and therefore ultimate ownership of the royalty interest wells was uncertain between Freehold and Canpar. The project relating to these interests was completed in 2015 with a settlement $0.8 million recognized in other income.

At September 30, 2016, there was $nil (December 31, 2015 – $nil) in accounts receivable and accounts payable and accrued liabilities relating to transactions with Canpar.

(d) CN Pension Trust Funds

Concurrent with the closing of the bought deal public equity offering completed by Freehold on May 25, 2016, CN Pension Trust Funds invested approximately $20 million through the purchase of 1,732,000 common shares on a non-brokered private placement basis. The price paid per common share by CN Pension Trust Funds pursuant to the private placement was the same price paid per common share by purchasers pursuant to the bought deal pubic equity offering.

Concurrent with the closing of the bought deal public equity offering completed by Freehold on May 6, 2015, CN Pension Trust Funds invested approximately $33 million in Freehold through the purchase of 1,833,334 common shares on a non-brokered private placement basis. The price paid per common share by CN Pension Trust Funds pursuant to the private placement was the same price paid per common share by purchasers pursuant to the bought deal pubic equity offering.

All amounts owing to/from the Manager, Rife, and Canpar are unsecured, non-interesting bearing and due on demand. All transactions were in the normal course of operations and were measured at the amount of consideration established and agreed to by both parties.

## INTEREST AND FINANCING

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| ($000s, except as noted) | **2016** | 2015 | Change | **2016** | 2015 | Change |
| Interest and financing expense | **935** | 1,271 | -26% | **3,697** | 4,475 | -17% |
| Per boe ($) | **0.83** | 1.23 | -33% | **1.12** | 1.54 | -27% |

In Q3-2016, interest and financing expense decreased due to lower average debt levels. The average effective interest rate on advances under our credit facilities was 2.9% (Q3-2015 – 3.0%).

#### DEPLETION AND DEPRECIATION

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| ($000s, except as noted) | **2016** | 2015 | Change | **2016** | 2015 | Change |
| Depletion and depreciation | **25,777** | 26,354 | -2% | **77,919** | 69,306 | 12% |
| Per boe ($) | **22.82** | 25.42 | -10% | **23.50** | 23.83 | -1% |

Oil and gas properties and royalty interests, including the cost of production equipment, future capital costs associated with proved plus probable reserves, and the capitalized portion of the decommissioning liability, are depleted on the unit-of-production method based on estimated proved plus probable oil and gas reserves. The increase in depletion is a result of increased production volumes.

## Income Tax

As a corporation, taxable income is based on revenues (which will vary depending on commodity prices and production volumes) less allowable expenses including claims for both accumulated tax pools and tax pools associated with current year expenditures. For the three and nine months ended September 30, 2016, there was no current income tax expense (Q3-2015 - $nil). Freehold's tax pools at December 31, 2015 were $966 million, with further tax pools added in 2016 from $166 million of acquisitions and minor capital expenditures.

# Liquidity and Capital Resources

## Operating Activities

In Q3-2016 there was a net loss of $2.0 million (2015 net loss of $22.2 million). The 2015 net loss was the result of a $30.8 million impairment charge, with the difference in 2016 otherwise associated with lower revenues and the legal settlement in 2016 and a deferred tax recovery in 2015 resulting from the impairment charge. For the nine months ended September 30, 2016 the net loss was $12.8 million (2015 net income of $3.3 million) with the primary difference being the above mentioned items, in addition to a $24.3 million gain on a corporate acquisition that occurred in Q1-2015.

In 2016 funds from operations was down 13% in the third quarter and down 19% for the nine month period (compared to the same periods in 2015), owing to continued weakness in oil and natural gas prices. We consider funds from operations to be a key measure of operating performance as it demonstrates Freehold's ability to generate the necessary funds to fund capital expenditures, sustain dividends, and repay debt. We believe that such a measure provides a useful assessment of Freehold's operations on a continuing basis by eliminating certain non-cash charges. It is also used by research analysts to value and compare oil and gas companies, and it is frequently included in their published research when providing investment recommendations. Funds from operations per share is calculated based on the weighted average number of shares outstanding consistent with the calculation of net income per share.

#### NET INCOME AND FUNDS FROM OPERATIONS

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| ($000s, except as noted) | **2016** | 2015 | Change | **2016** | 2015 | Change |
| Net income (loss) (1) | **(1,962)** | (22,193) | -91% | **(12,801)** | 3,343 | -483% |
| Per share, basic and diluted ($) | **(0.02)** | (0.23) | -91% | **(0.12)** | 0.04 | -400% |
| Funds from operations (1) | **24,148** | 27,643 | -13% | **63,790** | 78,311 | -19% |
| Per share ($) | **0.21** | 0.28 | -25% | **0.59** | 0.89 | -34% |

(1) For the three and nine months ended September 30, 2016, net loss and funds from operations include a $1.1 million loss upon settlement of litigation.

## Financing Activities

We retain working capital primarily to fund capital expenditures or acquisitions and reduce bank indebtedness. In the oil and gas industry, accounts receivable from industry partners are typically settled in the following month. However, due to administrative complexity, payments to royalty owners are often delayed longer. Also, working capital at each period end can vary due to volume and price changes at each period end and unpaid capital expenditures.

### COMPONENTS OF WORKING CAPITAL

| ($000s) | Sep. 30 2016 | Jun. 30 2016 | Mar. 31 2016 | Dec. 31 2015 | Sep. 30 2015 |
|---|---|---|---|---|---|
| Cash | 860 | 419 | 329 | 876 | 263 |
| Accounts receivable | 22,543 | 22,723 | 16,305 | 21,046 | 23,795 |
| Current taxes receivable | - | 73 | 73 | 73 | 700 |
| Current assets | 23,403 | 23,215 | 16,707 | 21,995 | 24,758 |
| Dividends payable | (4,713) | (4,704) | (3,970) | (6,924) | (6,900) |
| Accounts payable and accrued liabilities | (5,813) | (8,542) | (8,756) | (9,826) | (11,669) |
| Current portion of share based and other compensation payable | (178) | (160) | (178) | (194) | (183) |
| Current liabilities | (10,704) | (13,406) | (12,904) | (16,944) | (18,752) |
| Working capital | 12,699 | 9,809 | 3,803 | 5,051 | 6,006 |

Working capital increased by $2.7 million in the third quarter of 2016 compared to the previous quarter. This was driven by a decrease in accounts payable and accrued liabilities, as there was very little capital expenditure activity occurring at the end of the third quarter 2016.

### DEBT ANALYSIS

| ($000s) | Sep. 30 2016 | Jun. 30 2016 | Mar. 31 2016 | Dec. 31 2015 | Sep. 30 2015 |
|---|---|---|---|---|---|
| Long-term debt | 100,000 | 108,000 | 153,000 | 152,000 | 155,000 |
| Short-term debt | - | - | - | - | - |
| Total debt | 100,000 | 108,000 | 153,000 | 152,000 | 155,000 |
| Working capital | (12,699) | (9,809) | (3,803) | (5,051) | (6,006) |
| Net debt obligations [1] | 87,301 | 98,191 | 149,197 | 146,949 | 148,994 |

(1) See Non-GAAP Financial Measures.

Net debt obligations decreased $10.9 million to $87.3 million from the previous quarter largely due to our free cash flow, which was used to pay down debt.

We have a $245 million extendible revolving term credit facility with a syndicate of four Canadian chartered banks and a $15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees. The facilities are secured with $400 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. At September 30, 2016, we had $160 million of available capacity under our credit and operating facilities.

Our borrowing base is dependent on our lenders review and interpretation of our reserves and future commodity prices. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice, of an amount that the indebtedness is in excess of the redetermined borrowing base. The facilities are extendible annually with the latest review completed in May 2016, extending the revolving period to May 2017, with no change to our borrowing base. In the event that the lenders do not consent to an extension, the revolving credit facility would revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period.

### FINANCIAL LEVERAGE AND COVERAGE RATIOS (1)

| | **Sep. 30 2016** | Jun. 30 2016 | Mar. 31 2016 | Dec. 31 2015 | Sep. 30 2015 |
|---|---|---|---|---|---|
| Net debt to funds from operations (times) (2) | **1.0** | 1.1 | 1.5 | 1.4 | 1.4 |
| Net debt to dividends (times) | **1.3** | 1.3 | 1.7 | 1.6 | 1.5 |
| Dividends to interest expense (times) | **13** | 15 | 16 | 16 | 18 |
| Net debt to net debt plus equity (%) | **9** | 10 | 17 | 17 | 16 |

(1) Funds from operations, dividends, and interest expense are 12-months trailing and do not include the proforma effects of our acquisitions.

(2) See Non-GAAP Financial Measures.

At September 30, 2016, net debt was 1.0 times 12-months trailing funds from operations and net debt obligations were 9% of total capitalization.

Under our credit facilities, we are restricted from declaring dividends if we are or would be in default under the facilities or if our borrowings thereunder exceed our borrowing base. As at September 30, 2016, we were in compliance with all such covenants. We are also restricted from declaring dividends if we do not satisfy the liquidity and solvency tests under the *Business Corporations Act* (Alberta).

**SHAREHOLDERS' CAPITAL**

| | September 30, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | Shares | Amount ($000s) | Shares | Amount ($000s) |
| Balance, beginning of period | 98,940,152 | 1,050,494 | 74,918,711 | 635,223 |
| Issued for dividend reinvestment plan | 488,060 | 4,997 | 1,218,129 | 17,225 |
| Issued for payment of management fee | 215,736 | 2,524 | 269,978 | 3,693 |
| Issued for deferred share unit plan redemption | 45,098 | 796 | - | - |
| Issued for equity offering | 18,160,900 | 209,759 | 22,533,334 | 405,600 |
| Issue cost, net of tax effect | - | (5,849) | - | (11,247) |
| Balance, end of period | 117,849,946 | 1,262,721 | 98,940,152 | 1,050,494 |

**SHARES OUTSTANDING**

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | Change | 2016 | 2015 | Change |
| Weighted average | | | | | | |
| Basic | 117,725,922 | 98,356,956 | 20% | 107,887,678 | 87,732,745 | 23% |
| Diluted | 117,725,922 | 98,356,956 | 20% | 107,887,678 | 87,899,108 | 23% |
| At period end | 117,849,946 | 98,599,212 | 20% | 117,849,946 | 98,599,212 | 20% |

As at September 30, 2016 and November 8, 2016 there were 117,849,969 shares outstanding. For the three and nine months ended September 30, 2016 and the three months ended September 30, 2015 DSUs were excluded from the calculation of diluted net loss per share as their effect was anti-dilutive.

## Dividend Policy

The Board reviews and determines the monthly dividend rate on a quarterly basis after considering expected commodity prices, foreign exchange rates, economic conditions, production volumes, DRIP participation levels, tax payable, and our capacity to finance operating and investing obligations. The dividend rate is established with the intent of absorbing short-term market volatility over several months. It also recognizes our intention to fund capital expenditures primarily through funds from operations and to maintain a strong balance sheet to take advantage of acquisition opportunities and withstand potential commodity price declines.

Freehold's dividends are designated as eligible dividends for Canadian income tax purposes.

**RECONCILIATION OF DIVIDENDS DECLARED**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| ($000s) | 2016 | 2015 | 2016 | 2015 |
| Funds from operations | 24,148 | 27,643 | 63,790 | 78,311 |
| Proceeds from the DRIP | 1,170 | 3,708 | 4,997 | 14,467 |
| Issuance of shares, net of issue costs | - | - | 201,747 | 390,236 |
| Debt additions | (8,000) | (9,000) | (52,000) | 16,000 |
| Acquisition advance | - | - | - | 949 |
| Acquisitions | (68) | (815) | (162,498) | (411,495) |
| Capital expenditures | (209) | (7,969) | (3,046) | (16,688) |
| Working capital change | (2,908) | 11,037 | (7,632) | (2,388) |
| Dividends declared | 14,133 | 24,604 | 45,358 | 69,392 |

**ACCUMULATED DIVIDENDS (1)**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| **Dividends declared** ($000s) | 14,133 | 24,604 | 45,358 | 69,392 |
| Accumulated, beginning of period | 1,457,196 | 1,380,620 | 1,425,971 | 1,335,832 |
| Accumulated, end of period | 1,471,329 | 1,405,224 | 1,471,329 | 1,405,224 |
| | | | | |
| **Dividends per share** ($) (2) | 0.12 | 0.25 | 0.42 | 0.79 |
| Accumulated, beginning of period | 30.23 | 29.47 | 29.93 | 28.93 |
| Accumulated, end of period | 30.35 | 29.72 | 30.35 | 29.72 |

(1) Accumulated dividends reflect distributions paid on trust units of Freeehold Royalty Trust (the predecessor of Freehold) from 1996 through 2010 and dividends paid on common shares of Freehold from 2011 to the present.

(2) Based on the number of shares issued and outstanding at each record date.

## Dividend Reinvestment Plan (DRIP)

In the third quarter of 2016, average participation in Freehold's DRIP was 8% (Q3-2015 – 14%). We issued 107,198 (Q3-2015 – 324,155) shares related to the DRIP with an ascribed value of $1.2 million (Q3-2015 – $3.7 million). The ascribed value was based on the weighted average closing price for the 10-trading days preceding each payment date.

The DRIP allowed for the issuance of shares from treasury at a 5% discount to market (i.e. 95% of the weighted average closing price for the 10 trading days preceding each payment date). During Q3-2016 the Board approved the suspension of the DRIP pending further notice, effective with the August dividend paid on September 15, 2016.

### DIVIDEND ANALYSIS

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| ($000s) | 2016 | 2015 | 2016 | 2015 |
| Dividends paid in cash | 12,954 | 22,834 | 42,572 | 58,513 |
| Dividends paid in shares (DRIP) | 1,170 | 3,708 | 4,997 | 14,467 |
| Total dividends paid (1) | 14,124 | 26,542 | 47,569 | 72,980 |
| Dividends declared | 14,133 | 24,604 | 45,358 | 69,392 |
| Funds from operations | 24,148 | 27,643 | 63,790 | 78,311 |
| Capital expenditures | 209 | 7,969 | 3,046 | 16,688 |
| Basic payout ratio (2) | 59% | 89% | 71% | 89% |
| Adjusted payout ratio (3) | 55% | 111% | 72% | 96% |

(1) Based on the dividend payment date which is generally on the 15th day of the month following the month it was declared.

(2) Dividends declared as a percentage of funds from operations (see Non-GAAP Financial Measures).

(3) Dividends paid in cash plus capital expenditures as a percentage of funds from operations (see Non-GAAP Financial Measures).

Our basic payout ratio was 59% for the third quarter of 2016 and 71% for the first nine months of 2016, with our monthly dividend being a lower portion of our funds from operations compared to the same periods last year.

## Investing Activities

### ACQUISITIONS AND CAPITAL EXPENDITURES

| | Three Months Ended September 30 | | | Nine Months Ended September 30 | | |
|---|---|---|---|---|---|---|
| ($000s) | 2016 | 2015 | Change | 2016 | 2015 | Change |
| Acquisitions | 68 | 815 | -92% | 162,498 | 411,495 | -61% |
| Capital expenditures | 209 | 7,969 | -97% | 3,046 | 16,688 | -82% |
| | 277 | 8,784 | -97% | 165,544 | 428,183 | -61% |

Freehold spent $0.2 million on capital expenditures associated with its working interest development in Q3-2016 and $3.0 million over the nine months ended September 30, 2016, as there were reduced capital commitments on our largely non-operated properties. Acquisition expenditures were minor in the current quarter but the nine months ended September 30, 2016 included $162 million for an extensive suite of royalty production and fee lands purchased from Husky Energy Inc. The effective date of the Husky Transaction was January 1, 2016 with the closing occurring on May 25, 2016.

## Loss On Settlement

In May 2009, a statement of claim was filed against Freehold for $9 million. The claim involved disputed land interests and royalty obligations. During the third quarter of 2016 Freehold settled the claim with a $0.9 million payment and removed $0.2 million of associated accounts receivable, recognizing a total  loss of $1.1 million.

# Additional Information

Additional information about Freehold, including our annual information form (AIF), is available on SEDAR at www.sedar.com and on our website at www.freeholdroyalties.com.

## Internal Controls

Freehold is required to comply with National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*. The certification of interim filings requires us to disclose in the MD&A any changes in our internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect our internal control over financial reporting. We confirm that no such changes were made to the internal controls over financial reporting during the three months ended September 30, 2016. The Chief Executive Officer and Chief Financial Officer have signed form 52-109F2, *Certification of Interim Filings*, which can be found on SEDAR at www.sedar.com.

## Forward-looking Statements

Certain statements contained in this MD&A constitute forward-looking statements. These statements relate to future events or our expectations of future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "forecast", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions (including the negatives thereof). These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and, as such, forward-looking statements included in this MD&A should not be unduly relied upon. These forward-looking statements are provided to allow readers to better understand our business and prospects.

In particular, this MD&A contains forward-looking statements under Business Environment, 2016 Guidance Update and 2017 Outlook pertaining to the following:

- our outlook for commodity prices including supply and demand factors relating to crude oil, heavy oil, and natural gas;
- light/heavy oil price differentials;
- changing economic conditions;
- our strategies and the expectation that those strategies will sustain production and reserves life and deliver attractive returns to shareholders over the long term;
- our acquisition criteria and the intent that such criteria will result in acquisitions being accretive to shareholders;
- foreign exchange rates;
- industry drilling, development activity on our royalty lands, and expected drilling in certain areas where we have interests;
- development of working interest properties;
- estimated capital budget and expenditures and the timing thereof;
- Freehold's decommissioning liability and timing of payment thereof;
- forecast 2016 and 2017 production, including product mix and percentage from royalties;
- forecast 2016 and 2017 percentage of operating income from royalties;

- forecast 2016 basic payout ratio;
- forecast 2016 year end net debt to funds from operations;
- estimates of natural production declines;
- key operating assumptions for 2016 and 2017, including operating costs and general and administrative costs;
- expectations for shut-in production;
- expected production additions from our strong audit function;
- our dividend policy and expectations for future dividends;
- treatment under governmental regulatory regimes and tax laws; and
- our assessment of litigation risk.

Our actual results could differ materially from those anticipated in these forward-looking statements because of many factors, the most significant of which are as follows:

- volatility in market prices for crude oil and natural gas;
- lack of pipeline capacity;
- currency fluctuations;
- changes in income tax laws or changes in tax laws, regulations, royalties, or incentive programs relating to the oil and gas industry;
- reliance on royalty payors to drill and produce on our lands and their ability to pay their obligations;
- uncertainties or imprecision associated with estimating oil and gas reserves;
- stock market volatility and our ability to access sufficient capital from internal and external sources;
- a significant or prolonged downturn in general economic conditions or industry activity;
- incorrect assessments of the value of acquisitions;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- geological, technical, drilling, and processing problems;
- environmental risks and liabilities inherent in oil and gas operations; and
- other factors discussed in Freehold's annual MD&A and audited financial statements for the year ended December 31, 2015, and in our AIF.

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things, the following:

- future crude oil and natural gas prices;
- future capital expenditure levels;
- future production levels;
- future exchange rates;
- future tax rates;
- future legislation,
- the cost of developing and expanding our assets;
- our ability and the ability of our industry partners and royalty payors to obtain equipment in a timely manner to carry out development activities;
- our ability to market our product successfully to current and new customers;
- our expectation for the consumption of crude oil and natural gas;

- our expectation for industry drilling levels;
- our expectations of shut-in production;
- our expections of production additions from our strong audit function;
- the impact of increasing competition;
- our ability to obtain financing on acceptable terms; and
- our ability to add production and reserves through our development and acquisition activities.

Key operating assumptions with respect to the forward-looking statements contained in this MD&A are provided in the Guidance Update and 2017 Outlook sections.

To the extent any guidance or forward-looking statements herein constitutes a financial outlook, they are included herein to provide readers with an understanding of management's plans and assumptions for budgeting purposes and readers are cautioned that the information may not be appropriate for other purposes. You are further cautioned that the preparation of financial statements in accordance with IFRS requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. These estimates may change, having either a positive or negative effect on net income (loss), as further information becomes available and as the economic environment changes.

The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement and speak only as of the date of this MD&A. Our policy for updating forward-looking statements is to update our key operating assumptions quarterly and, except as required by law, we do not undertake to update any other forward-looking statements.

## Conversion of Natural Gas to Barrels of Oil Equivalent (BOE)

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (boe). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 barrel). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio, based on the current price of crude oil to natural gas, is significantly different from the 6:1 energy equivalency ratio, using a 6:1 conversion ratio may be misleading as an indication of value.

## Non-GAAP Financial Measures

Within this MD&A, references are made to terms commonly used as key performance indicators in the oil and gas industry. We believe that operating income, operating netback, net debt obligations, net debt to funds from operations, basic payout ratio, adjusted payout ratio, free cash flow and cash costs are useful supplemental measures for management and investors to analyze operating performance, financial leverage, and liquidity, and we use these terms to facilitate the understanding and comparability of our results of operations and financial position. However, these terms do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

Operating income, which is calculated as gross revenue less royalties and operating expenses, represents the cash margin for product sold. Operating netback, which is calculated as average unit sales price less royalties and operating expenses, represents the cash margin for product sold, calculated on a per boe basis (see Netback Analysis).

Net debt obligations is long-term debt less working capital (current assets less current liabilities). Net debt to funds from operations is calculated as net debt obligations as a proportion of funds from operations for the previous twelve months (see Financing Activities).

Payout ratios are often used for dividend paying companies in the oil and gas industry to identify its dividend levels in relation to the funds it receives and uses in its capital and operational activities. Basic payout ratio is calculated as dividends declared as a percentage of funds from operations. Adjusted payout ratio is calculated as dividends paid in cash plus capital expenditures as a percentage of funds from operations.

Free cash flow is calculated by subtracting capital expenditures from funds from operations. Free cash flow is a measure often used by dividend paying companies to determine cash available for payment of dividends, paying down debt or investment.

Cash costs is a total of all recurring costs in the statement of income (loss) and deducted in determining funds from operations. For Freehold cash costs are identified as royalty expense, operating expense, general and administrative expense, interest expense and share based and other compensation expense (if paid out in the relevant period). It is a key input to funds from operations and an important measure reinforcing the high operating netback of our royalty properties.

We refer to various per boe figures which provide meaningful information on our operational performance. We derive per boe figures by dividing the relevant revenue or cost figure by the total volume of oil, NGL and natural gas production during the period, with natural gas converted to equivalent barrels of oil as described above.

# Condensed Consolidated Balance Sheets

| ($000s) (unaudited) | **September 30 2016** | December 31 2015 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash | **$ 860** | $ 876 |
| Accounts receivable | **22,543** | 21,046 |
| Current taxes receivable | **-** | 73 |
| | **23,403** | 21,995 |
| Exploration and evaluation assets (note 3) | **64,991** | 49,479 |
| Petroleum and natural gas interests (note 4) | **920,875** | 846,825 |
| Deferred income tax asset | **27,993** | 21,095 |
| | **$ 1,037,262** | $ 939,394 |
| **Liabilities and Shareholders' Equity** | | |
| Current liabilities: | | |
| Dividends payable | **$ 4,713** | $ 6,924 |
| Accounts payable and accrued liabilities | **5,813** | 9,826 |
| Current portion of share based and other compensation payable (note 8) | **178** | 194 |
| | **10,704** | 16,944 |
| Decommissioning liability | **29,790** | 27,635 |
| Share based and other compensation payable (note 8) | **620** | 191 |
| Long-term debt (note 5) | **100,000** | 152,000 |
| Shareholders' equity: | | |
| Shareholders' capital (note 6) | **1,262,721** | 1,050,494 |
| Contributed surplus | **2,738** | 3,282 |
| Deficit | **(369,311)** | (311,152) |
| | **896,148** | 742,624 |
| | **$ 1,037,262** | $ 939,394 |

See accompanying notes to interim condensed consolidated financial statements.

# Condensed Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

| (unaudited) ($000s, except per share and weighted average data) | Three Months Ended September 30 2016 | Three Months Ended September 30 2015 | Nine Months Ended September 30 2016 | Nine Months Ended September 30 2015 |
|---|---|---|---|---|
| Revenue: | | | | |
| Royalty income and working interest sales | **$ 32,923** | $ 36,076 | **$ 90,075** | $ 101,831 |
| Royalty expense | **(284)** | (685) | **(863)** | (2,192) |
| | **32,639** | 35,391 | **89,212** | 99,639 |
| Gain on corporate acquisition (note 2) | **-** | - | **-** | 24,340 |
| Other income (loss) (note 7, 10) | **(1,066)** | 756 | **(1,066)** | 756 |
| Expenses: | | | | |
| Operating | **4,408** | 4,790 | **12,678** | 13,673 |
| General and administrative | **1,927** | 2,418 | **7,484** | 8,223 |
| Share based and other compensation (note 8) | **174** | 5 | **960** | 696 |
| Interest and financing | **935** | 1,271 | **3,697** | 4,475 |
| Depletion and depreciation | **25,777** | 26,354 | **77,919** | 69,306 |
| Impairment | **-** | 30,800 | **-** | 30,800 |
| Accretion of decommissioning liability | **130** | 156 | **420** | 414 |
| Management fee (note 7) | **910** | 778 | **2,524** | 2,912 |
| | **34,261** | 66,572 | **105,682** | 130,499 |
| Loss before taxes | **(2,688)** | (30,425) | **(17,536)** | (5,764) |
| Income taxes: | | | | |
| Current recovery | **-** | - | **-** | (5,097) |
| Deferred recovery | **(726)** | (8,232) | **(4,735)** | (4,010) |
| | **(726)** | (8,232) | **(4,735)** | (9,107) |
| Net income (loss) and comprehensive income (loss) | **$ (1,962)** | $ (22,193) | **$ (12,801)** | $ 3,343 |
| Net income (loss) per share, basic and diluted | **$ (0.02)** | $ (0.23) | **$ (0.12)** | $ 0.04 |
| Weighted average number of shares: | | | | |
| Basic | **117,725,922** | 98,356,956 | **107,887,678** | 87,732,745 |
| Diluted (note 6) | **117,725,922** | 98,356,956 | **107,887,678** | 87,899,108 |

See accompanying notes to interim condensed consolidated financial statements.

# Condensed Consolidated Statements of Cash Flows

| ($000s) (unaudited) | Three Months Ended September 30 **2016** | Three Months Ended September 30 2015 | Nine Months Ended September 30 **2016** | Nine Months Ended September 30 2015 |
|---|---|---|---|---|
| Operating: | | | | |
| Net income (loss) | **$ (1,962)** | $ (22,193) | **$ (12,801)** | $ 3,343 |
| Items not involving cash: | | | | |
| Depletion and depreciation | **25,777** | 26,354 | **77,919** | 69,306 |
| Impairment | **-** | 30,800 | **-** | 30,800 |
| Share based and other compensation | **174** | 5 | **960** | 696 |
| Deferred income tax recovery | **(726)** | (8,232) | **(4,735)** | (4,010) |
| Accretion of decommissioning liability | **130** | 156 | **420** | 414 |
| Management fee | **910** | 778 | **2,524** | 2,912 |
| Gain on corporate acquisition | **-** | - | **-** | (24,340) |
| Expenditures on share based and other compensation | **(105)** | - | **(406)** | (619) |
| Decommissioning expenditures | **(50)** | (25) | **(91)** | (191) |
| Funds from operations | **24,148** | 27,643 | **63,790** | 78,311 |
| Changes in non-cash working capital | **(198)** | 12,354 | **(2,168)** | 4,630 |
| | **23,950** | 39,997 | **61,622** | 82,941 |
| Financing: | | | | |
| Issuance of shares, net of issue costs | **-** | - | **201,747** | 390,236 |
| Long-term debt | **(8,000)** | (9,000) | **(52,000)** | 16,000 |
| Dividends paid | **(12,954)** | (22,834) | **(42,572)** | (58,513) |
| | **(20,954)** | (31,834) | **107,175** | 347,723 |
| Investing: | | | | |
| Acquisition advance | **-** | - | **-** | 949 |
| Acquisitions | **(68)** | (815) | **(162,498)** | (411,495) |
| Capital expenditures | **(209)** | (7,969) | **(3,046)** | (16,688) |
| Changes in non-cash working capital | **(2,278)** | 36 | **(3,269)** | (4,293) |
| | **(2,555)** | (8,748) | **(168,813)** | (431,527) |
| Increase (decrease) in cash | **441** | (585) | **(16)** | (863) |
| Cash, beginning of period | **419** | 848 | **876** | 1,126 |
| Cash, end of period | **$ 860** | $ 263 | **$ 860** | $ 263 |

See accompanying notes to interim condensed consolidated financial statements.

# Condensed Consolidated Statements of Changes in Shareholders' Equity

| ($000s) (unaudited) | Nine Months Ended September 30 **2016** | 2015 |
|---|---|---|
| Shareholders' capital: | | |
| Balance, beginning of period | **$ 1,050,494** | $ 635,223 |
| Shares issued for dividend reinvestment plan | **4,997** | 14,467 |
| Shares issued for payment of management fee | **2,524** | 2,912 |
| Shares issued for deferred share unit plan redemption | **796** | - |
| Shares issued for equity offering | **209,759** | 405,600 |
| Issue costs, net of tax effect | **(5,849)** | (11,247) |
| Balance, end of period | **1,262,721** | 1,046,955 |
| Contributed surplus: | | |
| Balance, beginning of period | **3,282** | 2,577 |
| Share based compensation expense | **593** | 668 |
| Deferred share unit plan redemption | **(1,137)** | - |
| Balance, end of period | **2,738** | 3,245 |
| Deficit: | | |
| Balance, beginning of period | **(311,152)** | (216,933) |
| Net income (loss) and comprehensive income (loss) | **(12,801)** | 3,343 |
| Dividends declared | **(45,358)** | (69,392) |
| Balance, end of period | **(369,311)** | (282,982) |
| Total shareholders' equity | **$ 896,148** | $ 767,218 |

See accompanying notes to interim condensed consolidated financial statements.

# Notes to Interim
# Condensed Consolidated Financial Statements

For the three and nine months ended September 30, 2016 and 2015 (unaudited).

## 1. Basis of Presentation

Freehold Royalties Ltd. (Freehold) is a dividend-paying corporation incorporated under the laws of the Province of Alberta. Freehold's primary focus is acquiring and managing oil and gas royalties and developing and producing its working interest oil and gas assets.

Freehold's principal place of business is located at 400, 144 – 4 Avenue SW, Calgary, Alberta, Canada, T2P 3N4.

### a) Statement of Compliance

These interim condensed consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS) and International Accounting Standard (IAS) 34 *Interim Financial Reporting*. These interim condensed consolidated financial statements do not include all of the disclosures normally provided in annual financial statements. These interim condensed consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements and notes for the year ended December 31, 2015 and should be read in conjunction with the audited consolidated financial statements and notes for the year ended December 31, 2015.

These interim condensed consolidated financial statements were approved by the Board of Directors on November 8, 2016.

### b) Basis of Measurement and Principles of Consolidation

These interim condensed consolidated financial statements have been prepared on a historical cost basis, with the exception of certain share based compensation payable, and include the accounts of Freehold and its wholly-owned subsidiaries: 1872348 Alberta Ltd., Freehold Holdings Trust and Freehold Royalties Partnership. All inter-entity transactions have been eliminated.

### c) Recent Pronouncements

In May 2014, the IASB issued IFRS 15 *Revenue from Contracts with Customers*, which replaces IAS 11 *Construction Contracts*, IAS 18 *Revenue*, and other revenue related interpretations. The standard establishes a single revenue recognition framework that applies to contracts with customers. The effective date for adopting IFRS 15 in its entirety is January 1, 2018. The impact on Freehold's consolidated financial statements is yet to be determined.

In July 2014, the IASB completed a three-phase project to replace IAS 39 *Financial Instruments: Recognition and Measurement* with IFRS 9 *Financial Instruments*. The first two completed phases replaced the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The third phase describes a new hedge accounting model. The effective date for adopting IFRS 9 in its entirety is January 1, 2018. The impact on Freehold's consolidated financial statements is yet to be determined.

In January, 2016, the IASB issued IFRS 16 *Leases*, which replaces IAS 17 *Leases*. The standard establishes a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. Other areas of the lease accounting model have been impacted, including the definition of a lease. Transitional provisions have been provided. The effective date for adopting IFRS 16 in its entirety is January 1, 2019. The impact on Freehold's consolidated financial statements is yet to be determined.

## 2. Corporate Acquisition

On January 23, 2015 Freehold acquired all of the outstanding shares of Anderson Energy Ltd. ("Anderson") pursuant to a plan of arrangement under the *Business Corporations Act* (Alberta) for total consideration of $35 million with Freehold funding the deal through its existing credit facilities. This transaction added approximately $220 million to existing tax pools. The fair value of the petroleum and natural gas interests and decommissioning liabilities acquired was determined using internal estimates. A gain on corporate acquisition of $24.3 million was recognized as the estimated value of income tax pools less the fair value of assets and liabilities exceeded the consideration paid.

## 3. Exploration and Evaluation Assets

| ($000s) | **September 30 2016** | December 31 2015 |
|---|---|---|
| Balance, beginning of period | **49,479** | 37,852 |
| Acquisitions (note 4) | **17,980** | 14,300 |
| Transfers to petroleum and natural gas interests (note 4) | **(2,468)** | (2,673) |
| Balance, end of period | **64,991** | 49,479 |

## 4. Petroleum and Natural Gas Interests

| ($000s) | **September 30 2016** | December 31 2015 |
|---|---|---|
| **Cost** | | |
| Balance, beginning of period | **1,271,382** | 874,377 |
| Acquisitions | **144,518** | 369,585 |
| Capital expenditures | **3,046** | 22,295 |
| Capitalized portion of long term incentive plan | **111** | 11 |
| Transfers from exploration and evaluation assets (note 3) | **2,468** | 2,673 |
| Decommissioning liability additions and revisions | **1,826** | 2,441 |
| Balance, end of period | **1,423,351** | 1,271,382 |
| | | |
| **Accumulated depletion and depreciation** | | |
| Balance, beginning of period | **(424,557)** | (290,054) |
| Impairment | **-** | (38,800) |
| Depletion and depreciation | **(77,919)** | (95,703) |
| Balance, end of period | **(502,476)** | (424,557) |
| | | |
| **Net book value, end of period** | **920,875** | 846,825 |

On May 25, 2016, Freehold acquired an extensive suite of royalty production and lands for $161.8 million, including adjustments, which included $17.9 million of undeveloped land classified as an exploration and evaluation asset.

## 5. Long-term Debt

Freehold has a $245 million extendible revolving term credit facility with a syndicate of four Canadian chartered banks, on which $100 million was drawn at September 30, 2016. In addition, Freehold has available a $15 million extendible revolving operating facility.

The facilities are secured with $400 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice, of an amount that the indebtedness is in excess of the redetermined borrowing base. Freehold's borrowing base is dependent on the lenders review and interpretation of Freehold's reserves and future commodity prices with the next renewal to occur by May 2017. In the event that the lenders do not consent to an extension, the revolving credit facility would revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period.

Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees. At September 30, 2016 and December 31, 2015 the fair values of the long-term debt approximated its carrying value, as the long-term debt carries interest at prevailing market rates. For the nine months ended September 30, 2016, the average effective interest rate on advances under Freehold's credit facilities was 2.9% (2015 - 3.0%).

## 6. Shareholders' Capital

### SHARES ISSUED AND OUTSTANDING

| | **September 30, 2016** | | December 31, 2015 | |
|---|---|---|---|---|
| | **Shares** | **Amount ($000s)** | Shares | Amount ($000s) |
| Balance, beginning of period | **98,940,152** | **1,050,494** | 74,918,711 | 635,223 |
| Issued for dividend reinvestment plan | **488,060** | **4,997** | 1,218,129 | 17,225 |
| Issued for payment of management fee (note 7) | **215,736** | **2,524** | 269,978 | 3,693 |
| Issued for deferred share unit plan redemption | **45,098** | **796** | - | - |
| Issued for equity offering | **18,160,900** | **209,759** | 22,533,334 | 405,600 |
| Issue cost, net of tax effect | **-** | **(5,849)** | - | (11,247) |
| Balance, end of period | **117,849,946** | **1,262,721** | 98,940,152 | 1,050,494 |

On May 25, 2016, Freehold closed a bought deal equity offering, issuing 16,428,900 common shares and a private equity offering with CN Pension Trust Funds (see note 7) issuing 1,732,000 common shares, both at a price of $11.55 per share for gross proceeds of $209.8 million.

On May 6, 2015, Freehold closed a bought deal equity offering, issuing 20,700,000 common shares and a private equity offering with CN Pension Trust Funds issuing 1,833,334 common shares, both at a price of $18.00 per share for gross proceeds of $405.6 million.

For the three months and nine months ended September 30, 2016, Deferred Share Units were excluded from the calculation of diluted net loss per share as their effect was anti-dilutive.

## 7. Related Party Transactions

Freehold does not have any employees. Rife Resources Management Ltd. (the Manager) is the manager of Freehold. The Manager is a wholly-owned subsidiary of Rife Resources Ltd. (Rife), and two of Rife's directors are also directors of

Freehold. Rife is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of the Canadian National Railway Company), which in turn is a shareholder of Freehold. The Manager recovers its general and administrative costs and a portion of its long-term incentive plan costs and retirement benefit costs, and receives a quarterly management fee paid in shares. Canpar Holdings Ltd. (Canpar) is also managed by Rife and owned 100% by the CN Pension Trust Funds, and two of Canpar's directors are also directors of Freehold.

(a) Rife Resources Management Ltd.

The Manager provides certain services for a fee based on a specified number of shares per quarter, pursuant to the amended and restated management agreement. The amended and restated management agreement caps the management fee at 71,912 shares per quarter for 2016 and the number of shares to be issued per quarter as payment of the management fee decreases to a level of 5,500 shares per quarter by 2023. For the three months ended September 30, 2016, Freehold issued 71,912 shares (2015 – 71,912) as payment of the management fee to the Manager pursuant to the management agreement. For the three months ended September 30, 2016, the ascribed value of $0.9 million (2015 – $0.8 million) was based on the closing price of the shares on the last trading day of each quarter. The total number of shares issued for the nine months ended September 30, 2016 was 215,736 (2015 – 198,066) with an ascribed value of $2.5 million (2015 – $2.9 million).

For the three months ended September 30, 2016, the Manager charged $1.8 million in general and administrative costs (2015 – $1.9 million). For the nine months ended September 30, 2016, the Manager charged $6.8 million in general and administrative costs (2015 – $7.0 million). At September 30, 2016, there was $0.6 million (December 31, 2015 – $0.7 million) in accounts payable and accrued liabilities relating to these costs.

(b) Rife Resources Ltd.

Freehold maintains ownership interests in certain oil and gas properties operated by Rife. A portion of net operating revenues and capital expenditures represent joint operations amounts from Rife. At September 30, 2016, there was $0.1 million (December 31, 2015 - $nil) in accounts receivable related to these transactions. At September 30, 2016, there was $nil (December 31, 2015 - $nil) in accounts payable and accrued liabilities relating to these transactions.

In addition, Freehold receives royalties from Rife pursuant to various royalty agreements. For the three months ended September 30, 2016, Freehold received royalties of approximately $0.2 million (2015 – $0.4 million). For the nine months ended September 30, 2016, Freehold received royalties of approximately $0.6 million (2015 – $1.2 million). At September 30, 2016, there was $0.1 million (December 31, 2015 - $0.1 million) in accounts receivable relating to these transactions.

(c) Canpar Holdings Ltd.

Freehold and Canpar share mineral title ownership rights in a substantial land base in western Canada. Generally, Canpar owns mineral rights that were below the deepest producing formation at the time that Freehold was created, and Freehold holds the balance of the mineral rights. Given the nature of the mineral rights, which are dependent upon hydrocarbon pool formation classification as well as third party drilling data which is subject to change and revision, significant uncertainty can exist with respect to the royalty ownership of wells drilled and completed on lands where both Freehold and Canpar hold the mineral rights.

During 2015, Freehold and Canpar evaluated certain of these royalty interests where, among other factors, the identification of the reservoir formation was not straight forward and therefore ultimate ownership of the royalty interest wells was uncertain between Freehold and Canpar. The project relating to these interests was completed in 2015 with a settlement $0.8 million recognized in other income.

At September 30, 2016, there was $nil (December 31, 2015 – $nil) in accounts receivable and accounts payable and accrued liabilities relating to transactions with Canpar.

### (d) CN Pension Trust Funds

Concurrent with the closing of the bought deal public equity offering completed by Freehold on May 25, 2016, CN Pension Trust Funds invested approximately $20 million through the purchase of 1,732,000 common shares on a non-brokered private placement basis. The price paid per common share by CN Pension Trust Funds pursuant to the private placement was the same price paid per common share by purchasers pursuant to the bought deal pubic equity offering.

Concurrent with the closing of the bought deal public equity offering completed by Freehold on May 6, 2015, CN Pension Trust Funds invested approximately $33 million in Freehold through the purchase of 1,833,334 common shares on a non-brokered private placement basis. The price paid per common share by CN Pension Trust Funds pursuant to the private placement was the same price paid per common share by purchasers pursuant to the bought deal pubic equity offering.

All amounts owing to/from the Manager, Rife, and Canpar are unsecured, non-interesting bearing and due on demand. All transactions were in the normal course of operations and were measured at the amount of consideration established and agreed to by both parties.

## 8. Share Based and Other Compensation

### (a) Long-term Incentive Plan

Freehold participates in its proportionate share of a long-term incentive plan (LTIP) for all employees of Rife through the Manager. The 2013 LTIP grants valued at $0.1 million were paid out in 2016. For the three months ended September 30, 2016, Freehold expensed $0.2 million (2015 – $45,000 recovery) of share based compensation. The total expensed for the nine months ended September 30, 2016 was $0.5 million (2015 – $18,000) of share based compensation.

The following table reconciles the change in total accrued share-based incentive compensation:

| ($000s) | **September 30 2016** | December 31 2015 |
|---|---|---|
| Balance, beginning of period | **257** | 741 |
| Increase in liability | **612** | 61 |
| Cash payout | **(120)** | (545) |
| Balance, end of period | **749** | 257 |
| Current portion of liability | **129** | 120 |
| Long-term portion of liability | **620** | 137 |

The following table reconciles the incentive plan activity for the period:

### PHANTOM COMMON SHARES

| | **September 30 2016** | December 31 2015 |
|---|---|---|
| Balance, beginning of period | **150,316** | 126,073 |
| Issued | **105,735** | 57,019 |
| Dividends reinvested | **9,485** | 11,294 |
| Cash payout | **(44,150)** | (44,070) |
| Balance, end of period | **221,386** | 150,316 |

### (b) Deferred Share Unit Plan

Fully-vested deferred share units (DSUs) are granted annually to non-management directors. As at September 30, 2016, there were 167,097 DSUs outstanding (2015 – 173,626), which are redeemable for an equal number of shares (less withholding tax if necessary) after the director's retirement. During the nine months ended September 30, 2016, the Board granted a total of 46,663 DSUs to eligible directors as part of their annual compensation. Each eligible director received 5,525 DSUs and the Chair of the Board received 8,287 DSUs (for new directors a prorated amount). In addition, during the nine months ended September 30, 2016, two retired directors redeemed 64,424 DSUs, resulting in the issuance of 45,098 shares from treasury. In payment of withholding tax, 19,326 DSUs were cancelled and the cash value of $0.2 million was remitted to the Canada Revenue Agency.

For the three months ended September 30, 2016, Freehold recovered $11,000 (2015 – $47,000 expensed) of share based compensation with a corresponding offset to contributed surplus. The total expensed for the nine months ended September 30, 2016 was $0.5 million (2015 – $0.7 million).

### DEFERRED SHARE UNITS

| | **September 30 2016** | December 31 2015 |
|---|---|---|
| Balance, beginning of period | **177,012** | 136,455 |
| Annual grants | **46,663** | 28,007 |
| Additional resulting from dividends | **7,846** | 12,550 |
| Redeemed | **(64,424)** | - |
| Balance, end of period | **167,097** | 177,012 |

### (c) Retirement Benefit

Freehold participates in its proportionate share of a retirement benefit for certain former employees of Rife through the Manager. For the three months ended September 30, 2016, Freehold expensed $nil (2015 – $3,000) with a corresponding increase to the obligation. The total expensed for the nine months ended September 30, 2016 was $5,000 (2015 – $9,000).

| ($000s) | **September 30 2016** | December 31 2015 |
|---|---|---|
| Accrued benefit obligation, beginning of period | **128** | 191 |
| Current service cost | **5** | 11 |
| Payments | **(84)** | (74) |
| Accrued benefit obligation, end of period | **49** | 128 |
| Current portion of liability | **49** | 74 |
| Long-term portion of liability | **-** | 54 |

## 9. Supplemental Cash Flow Disclosure

### CASH EXPENSES PAID

| | Three Months ended September 30 | | Nine Months ended September 30 | |
|---|---|---|---|---|
| ($000s) | **2016** | 2015 | **2016** | 2015 |
| Interest | **865** | 1,212 | **3,498** | 4,371 |
| Taxes | **(73)** | (6,831) | **(73)** | (6,993) |

## 10.Loss On Settlement

In May 2009, a statement of claim was filed against Freehold for $9 million. The claim involved disputed land interests and royalty obligations. During the third quarter of 2016 Freehold settled the claim with a $0.9 million payment and removed $0.2 million of associated accounts receivable, recognizing a total loss of $1.1 million.

# CORPORATE INFORMATION

## Board of Directors

**Marvin F. Romanow**
Chair of the Board

**Gary R. Bugeaud** (1) (2)
Corporate Director

**Peter T. Harrison**
Manager, Oil and Gas Investments
CN Investment Division

**Douglas J. Kay** (3)
Corporate Director

**Arthur N. Korpach** (1)(2)
Corporate Director

**Susan M. MacKenzie** (2)(3)
Corporate Director

**Thomas J. Mullane**
President and Chief Executive Officer
Rife Resources Ltd.

**Aidan M. Walsh** (1)(3)
Chief Executive Officer
Baccalieu Energy Inc.

(1) Audit Committee
(2) Governance, Nominating and Compensation Committee
(3) Reserves Committee

## Officers

**Marvin F. Romanow**
Chair of the Board

**Thomas J. Mullane**
President and Chief Executive Officer

**Darren G. Gunderson**
Vice-President, Finance and Chief Financial Officer

**Michael J. Stone**
Vice-President, Land

**Michael J. Mogan**
Controller

**Karen C. Taylor**
Corporate Secretary

## Head Office

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## The Manager

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Manager, Investor Relations
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## Auditors

**KPMG LLP**

## Bankers

**Canadian Imperial Bank of Commerce**
**Bank of Montreal**
**Royal Bank of Canada**
**The Toronto-Dominion Bank**

## Legal Counsel

**Burnet, Duckworth & Palmer LLP**

## Reserve Evaluators

**Trimble Engineering Associates Ltd.**

## Stock Exchange and Trading Symbol

**Toronto Stock Exchange (TSX)**
**Common Shares: FRU**

## Transfer Agent and Registrar

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