Q2 2016

Freehold
ROYALTIES LTD.

SECOND QUARTER REPORT
SIX MONTHS, ENDED JUNE 30, 2016

Results at a Glance

	Three Months Ended June 30			Six Months Ended June 30		
FINANCIAL ($000s, except as noted)	**2016**	2015	Change	**2016**	2015	Change
Gross revenue	**32,219**	38,004	-15%	**57,152**	65,755	-13%
Net income (loss)	**(2,249)**	3,919	-157%	**(10,839)**	25,536	-142%
Per share, basic and diluted ($)	**(0.02)**	0.04	-150%	**(0.11)**	0.31	-135%
Funds from operations	**24,142**	28,730	-16%	**39,642**	50,668	-22%
Per share, basic ($)	**0.23**	0.32	-28%	**0.39**	0.62	-37%
Operating income (1)	**28,011**	32,733	-14%	**48,303**	55,365	-13%
Operating income from royalties (%)	**91**	85	7%	**94**	84	12%
Acquisitions	**162,211**	342,310	-53%	**162,430**	410,680	-60%
Capital expenditures	**753**	2,750	-73%	**2,837**	8,719	-67%
Dividends declared	**13,380**	24,459	-45%	**31,225**	44,788	-30%
Per share ($) (2)	**0.12**	0.27	-56%	**0.30**	0.54	-44%
Net debt obligations (1)	**98,191**	146,992	-33%	**98,191**	146,992	-33%
Shares outstanding, period end (000s)	**117,652**	98,203	20%	**117,652**	98,203	20%
Average shares outstanding (000s) (3)	**106,736**	89,388	19%	**102,914**	82,333	25%
OPERATING						
Average daily production (boe/d) (4)	**12,041**	10,617	13%	**12,006**	10,338	16%
Average price realizations ($/boe) (4)	**28.48**	38.63	-26%	**25.37**	34.36	-26%
Operating netback ($/boe) (1) (4)	**25.57**	33.88	-25%	**22.11**	29.58	-25%

(1) See Non-GAAP Financial Measures.
(2) Based on the number of shares issued and outstanding at each record date.
(3) Weighted average number of shares outstanding during the period, basic.
(4) See Conversion of Natural Gas to Barrels of Oil Equivalent (boe).

Update

Effective with the August dividend Freehold's Board of Directors (the Board) has approved the suspension of Freehold's dividend reinvestment plan (DRIP) pending further notice. As of September 15, 2016, shareholders that were enrolled in the DRIP will receive the regular monthly cash dividend of $0.04 per share. Participants in the DRIP will still receive shares in lieu of the monthly cash dividends to be paid on August 15, 2016 to shareholders of record as at July 31, 2016.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) was prepared as of August 4, 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 six months ended June 30, 2016, and previous periods, and the outlook for Freehold based on information available as of August 4, 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 six months ended June 30, 2016 and June 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.

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 approximtely 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 (91% in Q2-2016) 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

Q2-2016 brought renewed optimism for an improving crude oil price environment as prices rallied off the lows set early in the year driven by what appeared to be improving global oil fundamentals. For the quarter West Texas Intermediate (WTI) prices averaged U.S.$45.59/bbl, up 36% when compared to Q1-2016 but down 21% versus the same period last year. Western Canadian Select (WCS) prices averaged $41.62/bbl, a 58% improvement versus Q1-2016, however down 27% versus Q2-2015.

Key macro drivers of crude oil prices over the quarter included a trending down in U.S. production volumes and a declining rig count. With WTI prices in the U.S.$40.00-$50.00/bbl range incremental growth out of the U.S. is likely to come solely from the Permian Basin which is not likely to offset declines from other plays. Similarly within Canada, the Deep Basin, Viking and southeast Saskatchewan continue to attract capital, however conventional volumes are declining. Outside of North America, the OPEC meeting at the beginning of June provided no resolution on a production ceiling. In the near-term, we expect headwinds to come from the continued ramping up of volumes within Iran, offset by geopolitical concerns in Nigeria and Venezuela.

We continue to maintain a modestly bullish view on prices. While 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 $1.25/mcf in Q2-2016, down 41% from Q1-2016 and a 53% decrease versus the same period in 2015. Similar to the macro environment for oil, natural gas fundamentals continue to be challenged by growing supplies within North America despite prices remaining relatively weak. U.S. natural gas production remains resilient with shale plays such as the Marcellus and Utica displaying material growth despite bottlenecks in infrastructure and material price discounts. However, with the decline in oil focused drilling within the U.S, we have seen a retreat in associated natural gas volumes, providing some momentum for pricing through the back half of 2016. Within Canada pricing is expected to remain challenged in the second half of 2016 and 2017 as volumes become further displaced by growth out of the U.S.

Industry Activity

In April 2016, the Petroleum Services Association of Canada (PSAC) updated its 2016 drilling forecast. The group is currently projecting 3,315 wells drilled through 2016, representing a decrease of 1,835 wells and an approximate 36% decline from PSAC's original 2016 forecast unveiled in November 2015. PSAC based its updated 2016 forecast on average natural gas prices of $1.60/mcf AECO, and WTI crude oil prices of U.S.$35.00/bbl.

ROYALTY INTEREST DRILLING

	Three Months Ended June 30 (1)				Six Months Ended June 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	**11**	**0.3**	68	4.5	**59**	**3.5**	96	5.8
Unitized wells (3)	**12**	**0.1**	41	0.2	**49**	**0.3**	87	0.5
Total	**23**	**0.4**	109	4.7	**108**	**3.8**	183	6.3
Royalty joint venture (4)	-		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, 108 (3.8 equivalent net) wells were drilled on our royalty lands through Q2-2016. This represented a 40% 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 was impacted by the absence of activity within our Dodsland Viking area through the first half of the year. With the recent change of the operator in this area, it is expected activity will ramp-up into year-end.

Outside of the Viking, we had two successful Shaunavon locations drilled over the quarter and to date a further ten locations have been licenced by the same operator. In June, an operator completed a Frobisher location in the Winmore area of Saskatchewan. In the Deep Basin, we have seen activity in the Ansel area with prospects targeting the Wilrich. In Pembina, an operator drilled two Cardium locations over the quarter which should come onstream in Q3-2016. An operator also drilled a deep Devonian location in the Morningside area in Q2-2016.

Guidance Update

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

- We have increased our production guidance from 11,400 boe/d to 11,700 boe/d, reflecting lower than expected decline within our royalty production and positive prior period adjustments. Volumes are expected to be weighted approximately 59% oil and natural gas liquids (NGL's) and 41% natural gas. We continue to maintain our royalty focus with royalty production accounting for 80% of forecasted 2016 production and 93% of operating income.
- We have revised upward our 2016 AECO natural gas price assumption from $1.80/mcf to $2.00/mcf.
- Increased expected royalty production, which has no operating costs, has resulted in a downward revision to our operating costs from $4.00/boe to $3.75/boe.
- Our G&A costs have been reduced from $2.50/boe to $2.40/boe, reflecting the increased production guidance.
- Freehold's Board has approved the suspension of the DRIP pending further notice, resulting in estimates for our dividends paid in shares for the full year decreasing from $8 million to $5 million.
- Our capital spending budget remains at $7 million. A large percentage of our capital expenditure program is non-operated and the activity level is difficult to predict.
- Weighted average shares outstanding have increased from 109 million to 110 million due to the full exercise of the over-allotment option relating to our May 2016 financing.
- Based on the announced DRIP suspension and changes to certain operating assumptions, we forecast our 2016 basic payout ratio to be approximately 74% (previously 82%).
- We forecast year-end net debt to funds from operations of approximately 1.1 times based on our revised key operating assumptions (excluding the proforma effects of acquisitions).

KEY OPERATING ASSUMPTIONS

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

(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).

Results of Operations

2016 Second Quarter Highlights:

- Freehold's production averaged a record 12,041 boe/d, a 13% improvement over Q2-2015 and 1% increase over Q1-2016. Gains in production were largely driven by acquisition activity and another strong quarter from our audit function which was largely responsible for approximately 475 boe/d of prior period adjustments, including compensatory royalties on our mineral title lands.
- Royalty production was up 21% compared to Q2-2015, averaging 9,725 boe/d.
- Funds from operations totaled $24.1 million ($0.23/share) in Q2-2016, up 55% from Q1-2016 driven primarily by upward momentum in oil prices and higher production, but down 16% from the same quarter last year due to reduced commodity prices offset somewhat by higher production.
- Royalties accounted for 91% of operating income and 81% of production, reinforcing our royalty focus.
- On May 25, 2016, Freehold acquired an extensive suite of royalty production and fee lands from certain affiliates of Husky Energy Inc. for $162 million, including adjustments (the Husky Transaction). After closing the Husky Transaction, Freehold's royalty acreage now totals 5.9 million acres (73% increase).
- After a review of our prospect inventory, including the upside from the Husky Transaction, we estimate that we have greater than 10 years of free drilling on our royalty lands.
- The Husky Transaction was funded by a concurrent $190 million public equity financing (after exercise of 15% over-allotment option but before underwriters' fees) and a $20 million concurrent private placement to CN Pension Trust Funds (see Related Party Transactions), both at a share price of $11.55, with remaining funds allocated to debt repayment.
- In Q2-2016, Freehold issued 15 leases, with the majority of the interest focused on Freehold's southeast Saskatchewan royalty lands. Net capital expenditures on our working interest properties totaled $0.8 million over the quarter.
- Dividends declared for Q2-2016 totaled $0.12 per share, down from $0.27 per share one year ago.
- Basic payout ratio (dividends declared/funds from operations) for Q2-2016 totaled 55% while the adjusted payout ratio (cash dividends plus capital expenditures/funds from operations) for the same period was 50%.
- At June 30, 2016, net debt obligations totaled $98.2 million, down $51.0 million from $149.2 million at March 31, 2016. This implies a net debt to 12-month trailing funds from operations ratio of 1.1 times (0.9 times including the proforma effects of acquisitions).

Subsequent Events

Effective with the August dividend, the Board has approved the suspension of the DRIP pending further notice. Given the above changes and revised guidance, Freehold will continue to maintain a conservative balance sheet with a forecasted adjusted payout ratio (cash dividends plus capital expenditures/funds from operations) through 2016 of 78%.

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 half of 2016.
- Fluctuations in foreign exchange rates affected our oil price realizations, resulting in recent 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 half 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.
- Dividends paid in shares through the DRIP are dependent on the participation levels of our shareholders, which is subject to change at their discretion.
- 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 $711 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	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial ($000s, except as noted)								
Revenue, net of royalty expense	**31,903**	24,670	33,728	35,391	37,222	27,026	42,597	50,625
Funds from operations	**24,142**	15,500	25,509	27,643	28,730	21,938	30,774	39,561
Per share, basic ($)	**0.23**	0.16	0.26	0.28	0.32	0.29	0.41	0.54
Net income (loss)	**(2,249)**	(8,590)	(7,423)	(22,193)	3,919	21,617	11,082	17,913
Per share, basic and diluted ($)	**(0.02)**	(0.09)	(0.08)	(0.23)	0.04	0.29	0.15	0.24
Dividends declared	**13,380**	17,845	20,747	24,604	24,459	20,329	31,353	31,148
Per share ($) (1)	**0.12**	0.18	0.21	0.25	0.27	0.27	0.42	0.42
Basic payout ratio (%) (2)	**55**	115	81	89	85	93	102	79
Operating Income (2)	**28,011**	20,292	29,186	30,601	32,733	22,632	37,584	46,012
Operating income from royalties (%)	**91**	97	89	90	85	83	80	78
Dividends paid in shares (DRIP)	**1,443**	2,384	2,758	3,708	2,398	8,361	10,915	6,170
Average DRIP participation rate (%) (3)	**11**	11	13	14	11	35	35	20
Acquisitions	**162,211**	219	(143)	815	342,310	68,370	60,566	76,780
Capital expenditures	**753**	2,084	5,607	7,969	2,750	5,969	13,500	2,811
Net debt obligations (2)	**98,191**	149,197	146,949	148,994	146,992	198,834	135,810	122,091
Shares outstanding								
Weighted average, basic (000s)	**106,736**	99,093	98,731	98,357	89,388	75,199	74,545	73,214
At quarter end (000s)	**117,652**	99,284	98,940	98,599	98,203	75,457	74,919	74,286
Operating ($/boe, except as noted)								
Daily production (boe/d) (4)	**12,041**	11,974	11,815	11,266	10,617	10,058	9,836	9,430
Royalty interest (%)	**81**	79	78	78	76	71	74	75
Average selling price	**28.48**	22.23	30.34	34.11	38.63	29.80	47.46	59.54
Operating netback (2)	**25.57**	18.62	26.85	29.52	33.88	25.01	41.54	53.03
Operating expenses	**3.55**	4.02	4.18	4.62	4.65	4.85	5.54	5.32
Working interest properties	**18.47**	19.41	19.24	20.78	19.14	16.87	21.66	21.05
Net general and administrative expenses (5)	**2.04**	3.05	2.23	2.33	2.34	3.92	2.32	2.16
Benchmark Prices								
WTI crude oil (US$/bbl)	**45.59**	33.45	42.18	46.43	57.94	48.64	73.15	97.15
Exchange rate (US$/Cdn$)	**0.78**	0.73	0.75	0.76	0.81	0.81	0.88	0.92
Edmonton Par crude oil (Cdn$/bbl)	**54.70**	40.84	52.89	56.23	67.75	51.95	75.79	97.10
Western Canadian Select (WCS) (Cdn$/bbl)	**41.62**	26.32	36.86	43.29	56.97	42.14	66.74	83.82
AECO natural gas (Cdn$/Mcf)	**1.25**	2.11	2.65	2.80	2.67	2.95	4.01	4.22
Share Trading Performance								
High ($)	**13.00**	12.05	13.52	16.07	19.04	20.62	23.27	26.92
Low ($)	**9.66**	8.29	9.00	8.73	15.86	16.14	17.02	22.64
Close ($)	**11.91**	10.54	10.86	10.82	16.14	17.94	19.12	23.16
Volume (000s)	**23,559**	19,690	19,312	22,753	18,912	14,297	18,607	10,412

(1) Based on the number of shares issued and outstanding at each record date.
(2) See Non-GAAP Financial Measures
(3) Participation in our DRIP is subject to change monthly at the participants' discretion.
(4) Reported production for a period may include adjustments from previous production periods.
(5) Excludes share based and other compensation.

AVERAGE DAILY PRODUCTION

	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015	Change	**2016**	2015	Change
Royalty interest [(1)]						
Oil (bbls/d)	**5,030**	4,157	21%	**5,123**	3,838	33%
NGL (bbls/d)	**530**	410	29%	**571**	417	37%
Natural gas (Mcf/d)	**24,988**	20,834	20%	**23,498**	20,095	17%
Oil equivalent (boe/d)	**9,725**	8,039	21%	**9,610**	7,604	26%
Working interest [(1)]						
Oil (bbls/d)	**1,366**	1,616	-15%	**1,448**	1,777	-19%
NGL (bbls/d)	**210**	150	40%	**198**	154	29%
Natural gas (Mcf/d)	**4,439**	4,870	-9%	**4,501**	4,820	-7%
Oil equivalent (boe/d)	**2,316**	2,578	-10%	**2,396**	2,734	-12%
Total						
Oil (bbls/d)	**6,396**	5,773	11%	**6,571**	5,615	17%
NGL (bbls/d)	**740**	560	32%	**769**	571	35%
Natural gas (Mcf/d)	**29,427**	25,704	14%	**27,999**	24,915	12%
Oil equivalent (boe/d)	**12,041**	10,617	13%	**12,006**	10,338	16%
Number of days in period (days)	**91**	91	0%	**182**	181	1%
Total volumes during period (Mboe)	**1,096**	966	13%	**2,185**	1,871	17%

(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 six months of 2016 was 39% natural gas, 36% light and medium oil, 19% heavy oil and 6% NGL's. Over the past three years, the composition of our liquids volumes have become lighter in composition, 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 increased 13% in the quarter, while natural gas production rose 14%. Much of these gains in production are attributed to acquisition activity in 2015 and Q2-2016. Over the quarter, there were also positive prior period adjustments of approximately 475 boe/d (approximately 60% oil and NGL), the majority resulting from our strong audit function, including compensatory royalties realized on our mineral title lands. In Q2-2015 prior period adjustments were 100 boe/d (100% natural gas).

Working interest production decreased 10% versus Q2-2015 largely due to decreased spending.

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 efforts we carefully monitor our royalty receivables and may choose to take our royalty in-kind if there are benefits to 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 prices, and the balance is 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 June 30			Six Months Ended June 30		
	2016	2015	Change	**2016**	2015	Change
WTI crude oil (US$/bbl)	**45.59**	57.94	-21%	**39.52**	53.29	-26%
Exchange rate (US$/Cdn$)	**0.78**	0.81	-4%	**0.75**	0.81	-7%
Edmonton Par crude oil (Cdn$/bbl)	**54.70**	67.75	-19%	**47.77**	59.85	-20%
Western Canadian Select (WCS) (Cdn$/bbl)	**41.62**	56.97	-27%	**33.97**	49.55	-31%
WTI/Edmonton Par differential ($/bbl)	**9.11**	9.81	-7%	**8.25**	6.56	26%
Edmonton Par/WCS differential (Cdn$/bbl)	**(13.08)**	(10.78)	21%	**(13.80)**	(10.30)	34%
AECO natural gas (Cdn$/Mcf)	**1.25**	2.67	-53%	**1.68**	2.81	-40%

Commodity prices in Q2-2016 were down significantly year over year due to weakening supply/demand fundamentals, with WTI dropping 21% versus last year. WCS was further negatively impacted by a widening differential to Edmonton Par, as the Edmonton Par/WCS differential increased by 21% from Q2-2015, leaving WCS 27% lower than the same quarter last year. AECO natural gas in Q2-2016 was down 53% 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 4% lower than in Q2-2015 which helped to offset the drop in WTI.

AVERAGE SELLING PRICES

	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015	Change	**2016**	2015	Change
Oil ($/bbl)	**45.56**	58.27	-22%	**37.61**	50.53	-26%
NGL ($/bbl)	**26.49**	31.62	-16%	**26.95**	27.46	-2%
Oil and NGL ($/bbl)	**43.58**	55.91	-22%	**36.49**	48.40	-25%
Natural gas ($/Mcf)	**1.09**	2.18	-50%	**1.31**	2.24	-42%
Oil equivalent ($/boe)	**28.48**	38.63	-26%	**25.37**	34.36	-26%

As the key driver behind a reduction in overall cash flows, liquids pricing in Q2-2016 was down versus the same period last year with our average realized oil and NGL price declining by 22%. Our average selling prices reflect production, quality and transportation differences from benchmark prices. Our realized price improved relative to WCS largely as a result of our 2015 royalty acquisitions which were mostly lighter oil.

Similar to oil, natural gas prices trended down over the quarter, decreasing 50% 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. The discount for the current quarter was lower than typical due to prior period adjustments.

Revenue

Gross revenue decreased 15% in Q2-2016 versus the same period last year due to lower commodity prices, partly offset by an increase in production. During the quarter we received a potash royalty payment of approximately $0.7 million that largely related to prior periods.

GROSS REVENUE BY PRODUCT

	Three Months Ended June 30			Six Months Ended June 30		
($000s)	**2016**	2015	Change	**2016**	2015	Change
Royalty interest revenue						
Oil	**20,842**	21,960	-5%	**35,098**	35,205	0%
NGL	**1,430**	1,321	8%	**3,208**	2,278	41%
Natural gas	**2,424**	4,051	-40%	**5,484**	7,936	-31%
Other [(1)]	**990**	545	82%	**1,551**	1,169	33%
	25,686	27,877	-8%	**45,341**	46,588	-3%
Working interest revenue						
Oil	**5,676**	8,651	-34%	**9,881**	16,150	-39%
NGL	**355**	289	23%	**567**	562	1%
Natural gas	**483**	1,048	-54%	**1,197**	2,164	-45%
Other [(1)]	**19**	139	-86%	**166**	291	-43%
	6,533	10,127	-35%	**11,811**	19,167	-38%
Total gross revenue						
Oil	**26,518**	30,611	-13%	**44,979**	51,355	-12%
NGL	**1,785**	1,610	11%	**3,775**	2,840	33%
Natural gas	**2,907**	5,099	-43%	**6,681**	10,100	-34%
Other [(1)]	**1,009**	684	48%	**1,717**	1,460	18%
	32,219	38,004	-15%	**57,152**	65,755	-13%

(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 Q2-2016 our volumes for both liquids and gas increased but weakness in commodity prices drove underperformance relative to Q2-2015.

GROSS REVENUE VARIANCES

	Three Months Ended June 30		Six Months Ended June 30	
($000s)	**2016 vs. 2015**	2015 vs. 2014	**2016 vs. 2015**	2015 vs. 2014
Oil and NGL				
Production increase	**3,188**	2,295	**7,890**	4,988
Price decrease	**(7,106)**	(17,726)	**(13,331)**	(38,812)
Net decrease	**(3,918)**	(15,431)	**(5,441)**	(33,824)
Natural gas				
Production increase	**368**	1,614	**768**	2,562
Price decrease	**(2,560)**	(2,938)	**(4,187)**	(7,187)
Net decrease	**(2,192)**	(1,324)	**(3,419)**	(4,625)
Other [(1)]	**325**	83	**257**	328
Gross revenue decrease	**(5,785)**	(16,672)	**(8,603)**	(38,121)

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

NET REVENUE

($000s)	Three Months Ended June 30 2016	2015	Change	Six Months Ended June 30 2016	2015	Change
Gross revenue	**32,219**	38,004	-15%	**57,152**	65,755	-13%
Royalty expense [1]	**(316)**	(782)	-60%	**(579)**	(1,507)	-62%
Net revenue	**31,903**	37,222	-14%	**56,573**	64,248	-12%

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

Expenses

ROYALTY EXPENSE [1]

($000s, except as noted)	Three Months Ended June 30 2016	2015	Change	Six Months Ended June 30 2016	2015	Change
Working interest	**235**	602	-61%	**496**	1,325	-63%
Per boe ($)	**1.12**	2.57	-56%	**1.14**	2.68	-57%
Royalty interest [2]	**81**	180	-55%	**83**	182	-54%
Per boe ($)	**0.09**	0.25	-64%	**0.05**	0.13	-62%
Total	**316**	782	-60%	**579**	1,507	-62%
Per boe ($)	**0.29**	0.81	-64%	**0.26**	0.81	-68%

(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 64% on a boe basis in Q2-2016 versus the same period in 2015 due to the retreat in pricing and increased royalty production as a percentage of total production. We do not incur Crown or third party royalty expenses on production from our royalty interest properties other than minor freehold mineral taxes. As the royalty owner, we receive the royalty as income from other companies.

OPERATING EXPENSES

($000s, except as noted)	Three Months Ended June 30 2016	2015	Change	Six Months Ended June 30 2016	2015	Change
Working interest	**3,892**	4,489	-13%	**8,270**	8,883	-7%
Per boe ($)	**18.47**	19.14	-4%	**18.96**	17.94	6%
Royalty interest [1]	**-**	-	-	**-**	-	-
Per boe ($)	**-**	-	-	**-**	-	-
Total operating expenses	**3,892**	4,489	-13%	**8,270**	8,883	-7%
Total ($/boe)	**3.55**	4.65	-24%	**3.78**	4.75	-20%

(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 little control over expenses.

On a total boe basis Q2-2016 operating costs averaged $3.55/boe, a 24% decrease from the same period in 2015, reflecting increased royalty production as a percentage of total production. Operating costs within our working interest properties were also down 13% versus the previous year reflecting lower working interest production and industry cost deflation.

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 in H1-2016 and more importantly contributed 94% of operating income.

OPERATING INCOME (1)

	Six months ended June 30, 2016		
($000s)	Royalty Interest	Working Interest	**Total**
Gross revenue (2)	45,341	11,811	**57,152**
Royalty expense (3)	(83)	(496)	**(579)**
Net revenue	45,258	11,315	**56,573**
Operating expense	-	(8,270)	**(8,270)**
Operating income	45,258	3,045	**48,303**
Percentage by category	94%	6%	**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 June 30			Six Months Ended June 30		
($/boe)	**2016**	2015	Change	**2016**	2015	Change
Gross revenue (1)	**29.41**	39.34	-25%	**26.15**	35.14	-26%
Royalty expense (2)	**(0.29)**	(0.81)	-64%	**(0.26)**	(0.81)	-68%
Operating expenses	**(3.55)**	(4.65)	-24%	**(3.78)**	(4.75)	-20%
Operating netback (3)	**25.57**	33.88	-25%	**22.11**	29.58	-25%

(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 25% versus Q2-2015 mainly as a result of lower commodity prices.

GENERAL AND ADMINISTRATIVE EXPENSES

	Three Months Ended June 30			Six Months Ended June 30		
($000s, except as noted)	2016	2015	Change	2016	2015	Change
Gross general and administrative expenses	2,613	2,636	-1%	6,442	6,721	-4%
Less: capitalized and overhead recoveries	(374)	(380)	-2%	(885)	(916)	-3%
Net general and administrative expenses	2,239	2,256	-1%	5,557	5,805	-4%
Per boe ($)	2.04	2.34	-13%	2.54	3.10	-18%

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 Q2-2016 G&A charges were down 1% versus the same period in 2015. On a boe basis costs were down 13% to $2.04/boe largely a result of the production volumes we added through acquisitions in the second half of 2015 and through 2016. G&A expenses on a year-to-date boe basis are typically highest in the first quarter and decline throughout the remainder of the year as a number of annual expenses occur in the first quarter.

MANAGEMENT FEES (PAID IN SHARES)

	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015	Change	2016	2015	Change
Shares issued for management fees	71,912	71,666	0%	143,824	126,154	14%
Ascribed value ($000s) (1)	856	1,156	-26%	1,614	2,134	-24%
Per boe ($)	0.78	1.20	-35%	0.74	1.14	-35%

(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 and the DRIP, result 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 June 30			Six Months Ended June 30		
($000s, except as noted)	2016	2015	Change	2016	2015	Change
Gross LTIP	340	30	1033%	385	76	407%
Less: capitalized portion	(61)	(5)	1120%	(69)	(13)	431%
Net LTIP	279	25	1016%	316	63	402%
Deferred share unit plan	82	125	-34%	465	622	-25%
Retirement benefit	2	1	100%	5	6	-17%
Share based and other compensation	363	151	140%	786	691	14%
Per boe ($)	0.33	0.16	106%	0.36	0.37	-3%

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 Q2-2016 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. As at June 30, 2016, there were 191,890 DSUs outstanding, and as at August 4, 2016, there were 192,537 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 (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 June 30, 2016, Freehold issued 71,912 shares (2015 – 71,666) as payment of the management fee to the Manager pursuant to the management agreement. For the three months ended June 30, 2016, the ascribed value of $0.9 million (2015 – $1.2 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 six months ended June 30, 2015 was 143,824 (2015 – 126,154) with an ascribed value of $1.6 million (2015 – $2.1 million).

For the three months ended June 30, 2016, the Manager charged $2.1 million in general and administrative costs (2015 – $2.1 million). For the six months ended June 30, 2016, the Manager charged $5.0 million in general and administrative costs (2015 – $5.1 million). At June 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 June 30, 2016, there was $nil (December 31, 2015 - $nil) in accounts receivable and 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 June 30, 2016, Freehold received royalties of approximately $0.2 million (2015 – $0.5 million). For the six months ended June 30, 2016, Freehold received royalties of approximately $0.4 million (2015 – $0.8 million). At June 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. At June 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 equity offering 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.

Concurrent with the closing of the bought deal equity offering 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.

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 June 30			Six Months Ended June 30		
($000s, except as noted)	**2016**	2015	Change	**2016**	2015	Change
Interest and financing expense	**1,552**	1,660	-7%	**2,762**	3,204	-14%
Per boe ($)	**1.42**	1.72	-17%	**1.26**	1.71	-26%

In Q2-2016, 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% (Q2-2015 – 3.0%).

DEPLETION AND DEPRECIATION

	Three Months Ended June 30			Six Months Ended June 30		
($000s, except as noted)	**2016**	2015	Change	**2016**	2015	Change
Depletion and depreciation	**25,940**	23,403	11%	**52,142**	42,952	21%
Per boe ($)	**23.67**	24.22	-2%	**23.86**	22.95	4%

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 six months ended June 30, 2016, there was no current income tax expense (Q2-2015 - $nil). Freehold's tax pools at December 31, 2015 were $966 million, with further tax pools added in 2016 from $165 million of acquisitions and minor capital expenditures.

Liquidity and Capital Resources

Operating Activities

Q2-2016 net loss was $2.2 million (2015 net income of $3.9 million), the difference primarily due to lower revenues and increased depletion and depreciation expense as a result of higher production volumes. For the six months ended June 30, 2016 the net loss was $10.9 million (2015 net income of $39.6 million) with an additional cause of the difference being a one-time $24.3 million gain on corporate acquisition that occurred in Q1-2015.

In 2016 funds from operations was down 16% in the second quarter and down 20% for the six month period (compared to 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 June 30			Six Months Ended June 30		
($000s, except as noted)	**2016**	2015	Change	**2016**	2015	Change
Net income (loss)	**(2,249)**	3,919	-157%	**(10,839)**	25,536	-142%
Per share, basic and diluted ($)	**(0.02)**	0.04	-150%	**(0.11)**	0.31	-135%
Funds from operations [1]	**24,142**	28,730	-16%	**39,642**	50,668	-22%
Per share ($)	**0.23**	0.32	-28%	**0.39**	0.62	-37%

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)	Jun. 30 2016	Mar. 31 2016	Dec. 31 2015	Sep. 30 2015	Jun. 30 2015
Cash	419	329	876	263	848
Accounts receivable	22,723	16,305	21,046	23,795	29,714
Current taxes receivable	73	73	73	700	7,532
Current assets	23,215	16,707	21,995	24,758	38,094
Dividends payable	(4,704)	(3,970)	(6,924)	(6,900)	(8,838)
Accounts payable and accrued liabilities	(8,542)	(8,756)	(9,826)	(11,669)	(12,030)
Current portion of share based and other compensation payable	(160)	(178)	(194)	(183)	(218)
Current liabilities	(13,406)	(12,904)	(16,944)	(18,752)	(21,086)
Working capital	9,809	3,803	5,051	6,006	17,008

Working capital increased by $6.0 million in the second quarter of 2016 compared to the previous quarter. This was driven by a increase in accounts receivable as oil prices were significantly higher at the end of the second quarter versus the end of the first quarter.

DEBT ANALYSIS

($000s)	Jun. 30 2016	Mar. 31 2016	Dec. 31 2015	Sep. 30 2015	Jun. 30 2015
Long-term debt	108,000	153,000	152,000	155,000	164,000
Short-term debt	-	-	-	-	-
Total debt	108,000	153,000	152,000	155,000	164,000
Working capital	(9,809)	(3,803)	(5,051)	(6,006)	(17,008)
Net debt obligations	98,191	149,197	146,949	148,994	146,992

(1) See Non-GAAP Financial Measures.

Net debt obligations decreased $51 million to $98 million from the previous quarter largely due to our equity raise, which was partly used to pay down debt. An increase in our funds from operations also allowed us to pay down some debt which was partially offset by the working capital changes mentioned above.

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 June 30, 2016, we had $152 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 latest review completed in May 2016, 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]

	Jun. 30 2016	Mar. 31 2016	Dec. 31 2015	Sep. 30 2015	Jun. 30 2015
Net debt to funds from operations (times) [2]	1.1	1.5	1.4	1.4	1.2
Net debt to dividends (times)	1.3	1.7	1.6	1.5	1.4
Dividends to interest expense (times)	15	16	16	18	19
Net debt to net debt plus equity (%)	10	17	17	16	15

(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 June 30, 2016, net debt was 1.1 times 12-months trailing funds from operations and net debt obligations were 10% 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 June 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

	June 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	380,862	3,827	1,218,129	17,225
Issued for payment of management fee	143,824	1,614	269,978	3,693
Issued for deferred share unit plan redemption	26,340	471	-	-
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	117,652,078	1,260,316	98,940,152	1,050,494

SHARES OUTSTANDING

	Three Months Ended June 30			Six Months Ended June 30		
	2016	2015	Change	2016	2015	Change
Weighted average						
Basic	106,735,748	89,388,195	19%	102,914,499	82,332,593	25%
Diluted	106,735,748	89,554,197	19%	102,914,499	82,496,335	25%
At period end	117,652,078	98,203,145	20%	117,652,078	98,203,145	20%

As at June 30, 2016, there were 117,652,078 shares outstanding, and as at August 4, 2016, there were 117,705,171 shares outstanding. For the three and six months ended June 30, 2016 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 June 30		Six Months Ended June 30	
($000s)	**2016**	2015	**2016**	2015
Funds from operations	**24,142**	28,730	**39,642**	50,668
Proceeds from the DRIP	**1,443**	2,398	**3,827**	10,759
Issuance of shares, net of issue costs	**201,747**	390,236	**201,747**	390,236
Debt additions	**(45,000)**	(46,000)	**(44,000)**	25,000
Acquisition advance	**-**	-	**-**	949
Acquisitions	**(162,211)**	(342,310)	**(162,430)**	(410,680)
Capital expenditures	**(753)**	(2,750)	**(2,837)**	(8,719)
Working capital change	**(5,988)**	(5,845)	**(4,724)**	(13,425)
Dividends declared	**13,380**	24,459	**31,225**	44,788

ACCUMULATED DIVIDENDS

	Three Months Ended June 30		Six Months Ended June 30	
	2016	2015	**2016**	2015
Dividends declared ($000s)	**13,380**	24,459	**31,225**	44,788
Accumulated, beginning of period	**1,443,816**	1,356,161	**1,425,971**	1,335,832
Accumulated, end of period	**1,457,196**	1,380,620	**1,457,196**	1,380,620
Dividends per share ($) (1)	**0.12**	0.27	**0.30**	0.54
Accumulated, beginning of period	**30.11**	29.20	**29.93**	28.93
Accumulated, end of period	**30.23**	29.47	**30.23**	29.47

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

Dividend Reinvestment Plan (DRIP)

In the second quarter of 2016, average participation in Freehold's DRIP was 11% (Q2-2015 – 11%). We issued 135,679 (Q2-2015 – 141,474) shares related to the DRIP with an ascribed value of $1.4 million (Q2-2015 – $2.4 million). Participation levels can fluctuate greatly on a month to month basis. 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). Subsequent to quarter end the Board has approved the suspension of the DRIP pending further notice, effective with August dividend to be paid on September 15, 2016.

DIVIDEND ANALYSIS

	Three Months Ended June 30		Six Months Ended June 30	
($000s)	**2016**	2015	**2016**	2015
Dividends paid in cash	**11,203**	20,014	**29,618**	35,679
Dividends paid in shares (DRIP)	**1,443**	2,398	**3,827**	10,759
Total dividends paid (1)	**12,646**	22,412	**33,445**	46,438
Dividends declared	**13,380**	24,459	**31,225**	44,788
Funds from operations	**24,142**	28,730	**39,642**	50,668
Capital expenditures	**753**	2,750	**2,837**	8,719
Basic payout ratio (2)	**55%**	85%	**79%**	88%
Adjusted payout ratio (3)	**50%**	79%	**82%**	88%

(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 for the second quarter of 2016 has decreased to 55% as a result of the decrease to our monthly dividend which is now a lower portion of our funds from operations.

Investing Activities

ACQUISITIONS AND CAPITAL EXPENDITURES

	Three Months Ended June 30			Six Months Ended June 30		
($000s)	**2016**	2015	Change	**2016**	2015	Change
Acquisitions	**162,211**	342,310	-53%	**162,430**	410,680	-60%
Capital expenditures	**753**	2,750	-73%	**2,837**	8,719	-67%
	162,964	345,060	-53%	**165,267**	419,399	-61%

Freehold acquired an extensive suite of royalty production and fee lands pursuant to the Husky Transaction for $162 million, including adjustments. The effective date of the Husky Transaction was January 1, 2016 with closing occurring on May 25, 2016.

Contingency

In May 2009, a statement of claim was filed against Freehold for $9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, Freehold has assessed the claim and believes the claim has no merit. The claim’s outcome is not determinable and therefore no liability has been recorded in the financial statements.

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 and six months ended June 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, Industry Activity, Guidance Update, Subsequent Events, and 2016 Second Quarter Highlights 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;
- average production, contribution from royalty lands and weighting of oil, NGL's and natural gas;
- our intent to maintain a conservative balance sheet;

- forecast 2016 basic and adjusted payout ratios;
- forecast year end net debt to funds from operations;
- key operating assumptions including operating costs and general and administrative costs;
- our dividend policy and expectations for future dividends;
- treatment under governmental regulatory regimes and tax laws;
- our assessment of litigation risk; and
- the estimate that we have greater than 10 years of free drilling on our royalty lands.

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;
- 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 section.

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 and adjusted payout ratio 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). In addition, we refer to various per boe figures, such as revenues and costs, also considered non-GAAP measures, 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.

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.

Condensed Consolidated Balance Sheets

($000s) (unaudited)	June 30 2016	December 31 2015
Assets		
Current assets:		
Cash	**$ 419**	$ 876
Accounts receivable	**22,723**	21,046
Current taxes receivable	**73**	73
	23,215	21,995
Exploration and evaluation assets (note 3)	**65,963**	49,479
Petroleum and natural gas interests (note 4)	**945,071**	846,825
Deferred income tax asset	**27,267**	21,095
	$ 1,061,516	$ 939,394
Liabilities and Shareholders' Equity		
Current liabilities:		
Dividends payable	**$ 4,704**	$ 6,924
Accounts payable and accrued liabilities	**8,542**	9,826
Current portion of share based and other compensation payable (note 8)	**160**	194
	13,406	16,944
Decommissioning liability	**29,420**	27,635
Share based and other compensation payable (note 8)	**411**	191
Long-term debt (note 5)	**108,000**	152,000
Shareholders' equity:		
Shareholders' capital (note 6)	**1,260,316**	1,050,494
Contributed surplus	**3,179**	3,282
Deficit	**(353,216)**	(311,152)
	910,279	742,624
	$ 1,061,516	$ 939,394

See accompanying notes to interim condensed consolidated financial statements.

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

(unaudited) ($000s, except per share and weighted average data)	Three Months Ended June 30 **2016**	 2015	Six Months Ended June 30 **2016**	 2015
Revenue:				
Royalty income and working interest sales	**$ 32,219**	$ 38,004	**$ 57,152**	$ 65,755
Royalty expense	**(316)**	(782)	**(579)**	(1,507)
	31,903	37,222	**56,573**	64,248
Gain on corporate acquisition (note 2)	**-**	-	**-**	24,340
Expenses:				
Operating	**3,892**	4,489	**8,270**	8,883
General and administrative	**2,239**	2,256	**5,557**	5,805
Share based and other compensation (note 8)	**363**	151	**786**	691
Interest and financing	**1,552**	1,660	**2,762**	3,204
Depletion and depreciation	**25,940**	23,403	**52,142**	42,952
Accretion of decommissioning liability	**142**	136	**290**	258
Management fee (note 7)	**856**	1,156	**1,614**	2,134
	34,984	33,251	**71,421**	63,927
Income (loss) before taxes	**(3,081)**	3,971	**(14,848)**	24,661
Income taxes:				
Current recovery	**-**	-	**-**	(5,097)
Deferred expense (recovery)	**(832)**	52	**(4,009)**	4,222
	(832)	52	**(4,009)**	(875)
Net income (loss) and comprehensive income (loss)	**$ (2,249)**	$ 3,919	**$ (10,839)**	$ 25,536
Net income (loss) per share, basic and diluted	**$ (0.02)**	$ 0.04	**$ (0.11)**	$ 0.31
Weighted average number of shares:				
Basic	**106,735,748**	89,388,195	**102,914,499**	82,332,593
Diluted (note 6)	**106,735,748**	89,554,197	**102,914,499**	82,496,335

See accompanying notes to interim condensed consolidated financial statements.

Condensed Consolidated Statements of Cash Flows

($000s) (unaudited)	Three Months Ended June 30 2016	Three Months Ended June 30 2015	Six Months Ended June 30 2016	Six Months Ended June 30 2015
Operating:				
Net income (loss)	**$ (2,249)**	$ 3,919	**$ (10,839)**	$ 25,536
Items not involving cash:				
Depletion and depreciation	**25,940**	23,403	**52,142**	42,952
Share based and other compensation	**363**	151	**786**	691
Deferred income tax expense (recovery)	**(832)**	52	**(4,009)**	4,222
Accretion of decommissioning liability	**142**	136	**290**	258
Management fee	**856**	1,156	**1,614**	2,134
Gain on corporate acquisition	**-**	-	**-**	(24,340)
Expenditures on share based and other compensation	**(42)**	(37)	**(301)**	(619)
Decommissioning expenditures	**(36)**	(50)	**(41)**	(166)
Funds from operations	**24,142**	28,730	**39,642**	50,668
Changes in non-cash working capital	**(6,931)**	(7,311)	**(1,970)**	(7,724)
	17,211	21,419	**37,672**	42,944
Financing:				
Issuance of shares, net of issue costs	**201,747**	390,236	**201,747**	390,236
Long-term debt	**(45,000)**	(46,000)	**(44,000)**	25,000
Dividends paid	**(11,203)**	(20,014)	**(29,618)**	(35,679)
	145,544	324,222	**128,129**	379,557
Investing:				
Acquisition advance	**-**	-	**-**	949
Acquisitions	**(162,211)**	(342,310)	**(162,430)**	(410,680)
Capital expenditures	**(753)**	(2,750)	**(2,837)**	(8,719)
Changes in non-cash working capital	**299**	(505)	**(991)**	(4,329)
	(162,665)	(345,565)	**(166,258)**	(422,779)
Increase (decrease) in cash	**90**	76	**(457)**	(278)
Cash, beginning of period	**329**	772	**876**	1,126
Cash, end of period	**$ 419**	$ 848	**$ 419**	$ 848

See accompanying notes to interim condensed consolidated financial statements.

Condensed Consolidated Statements of Changes in Shareholders' Equity

($000s) (unaudited)	Six Months Ended June 30 2016	2015
Shareholders' capital:		
Balance, beginning of period	**$ 1,050,494**	$ 635,223
Shares issued for dividend reinvestment plan	**3,827**	10,759
Shares issued for payment of management fee	**1,614**	2,134
Shares issued for deferred share unit plan redemption	**471**	-
Shares issued for equity offering	**209,759**	405,600
Issue costs, net of tax effect	**(5,849)**	(11,247)
Balance, end of period	**1,260,316**	1,042,469
Contributed surplus:		
Balance, beginning of period	**3,282**	2,577
Share based compensation expense	**570**	622
Deferred share unit plan redemption	**(673)**	-
Balance, end of period	**3,179**	3,199
Deficit:		
Balance, beginning of period	**(311,152)**	(216,933)
Net income (loss) and comprehensive income (loss)	**(10,839)**	25,536
Dividends declared	**(31,225)**	(44,788)
Balance, end of period	**(353,216)**	(236,185)
Total shareholders' equity	**$ 910,279**	$ 809,483

See accompanying notes to interim condensed consolidated financial statements.

Notes to Interim
Condensed Consolidated Financial Statements

For the three and six months ended June 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 August 4, 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)	**June 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)	**(1,496)**	(2,673)
Balance, end of period	**65,963**	49,479

4. Petroleum and Natural Gas Interests

($000s)	**June 30 2016**	December 31 2015
Cost		
Balance, beginning of period	**1,271,382**	874,377
Acquisitions	**144,450**	369,585
Capital expenditures	**2,837**	22,295
Capitalized portion of long term incentive plan	**69**	11
Transfers from exploration and evaluation assets (note 3)	**1,496**	2,673
Decommissioning liability additions and revisions	**1,536**	2,441
Balance, end of period	**1,421,770**	1,271,382
Accumulated depletion and depreciation		
Balance, beginning of period	**(424,557)**	(290,054)
Impairment	**-**	(38,800)
Depletion and depreciation	**(52,142)**	(95,703)
Balance, end of period	**(476,699)**	(424,557)
Net book value, end of period	**945,071**	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 $108 million was drawn at June 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 June 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 six months ended June 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

	June 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	**380,862**	**3,827**	1,218,129	17,225
Issued for payment of management fee (note 7)	**143,824**	**1,614**	269,978	3,693
Issued for deferred share unit plan redemption	**26,340**	**471**	-	-
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	**117,652,078**	**1,260,316**	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 six ended June 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 June 30, 2016, Freehold issued 71,912 shares (2015 – 71,666) as payment of the management fee to the Manager pursuant to the management agreement. For the three months ended June 30, 2016, the ascribed value of $0.9 million (2015 – $1.2 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 six months ended June 30, 2015 was 143,824 (2015 – 126,154) with an ascribed value of $1.6 million (2015 – $2.1 million).

For the three months ended June 30, 2016, the Manager charged $2.1 million in general and administrative costs (2015 – $2.1 million). For the six months ended June 30, 2016, the Manager charged $5.0 million in general and administrative costs (2015 – $5.1 million). At June 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 June 30, 2016, there was $nil (December 31, 2015 - $nil) in accounts receivable and 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 June 30, 2016, Freehold received royalties of approximately $0.2 million (2015 – $0.5 million). For the six months ended June 30, 2016, Freehold received royalties of approximately $0.4 million (2015 – $0.8 million). At June 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. At June 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 equity offering 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.

Concurrent with the closing of the bought deal equity offering 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.

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 June 30, 2016, Freehold expensed $0.3 million (2015 – $25,000) of share based compensation. The total expensed for the six months ended June 30, 2016 was $0.3 million (2015 – $0.1 million) of share based compensation.

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

($000s)	**June 30 2016**	December 31 2015
Balance, beginning of period	**257**	741
Increase in liability	**385**	61
Cash payout	**(120)**	(545)
Balance, end of period	**522**	257
Current portion of liability	**111**	120
Long-term portion of liability	**411**	137

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

PHANTOM COMMON SHARES

	June 30 2016	December 31 2015
Balance, beginning of period	**150,316**	126,073
Issued	**105,735**	57,019
Dividends reinvested	**7,064**	11,294
Cash payout	**(44,150)**	(44,070)
Balance, end of period	**218,965**	150,316

(b) Deferred Share Unit Plan

Fully-vested deferred share units (DSUs) are granted annually to non-management directors. As at June 30, 2016, there were 191,890 DSUs outstanding (2015 – 169,652), which are redeemable for an equal number of shares (less withholding tax if necessary) after the director's retirement. During the six months ended June 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 six months ended June 30, 2016, a retired director redeemed 37,627 DSUs, resulting in the issuance of 26,340 shares from treasury. In payment of withholding tax, 11,287 DSUs were cancelled and the cash value of $0.1 million was remitted to the Canada Revenue Agency.

For the three months ended June 30, 2016, Freehold expensed $0.1 million (2015 – $0.1 million) of share based compensation with a corresponding increase to contributed surplus. The total expensed for the six months ended June 30, 2016 was $0.5 million (2015 – $0.6 million).

DEFERRED SHARE UNITS

	June 30 2016	December 31 2015
Balance, beginning of period	**177,012**	136,455
Annual grants	**46,663**	28,007
Additional resulting from dividends	**5,842**	12,550
Redeemed	**(37,627)**	-
Balance, end of period	**191,890**	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 June 30, 2016, Freehold expensed $2,000 (2015 – $1,000) with a corresponding increase to the obligation. The total expensed for the six months ended June 30, 2016 was $5,000 (2015 – $6,000).

($000s)	June 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 June 30		Six Months ended June 30	
($000s)	**2016**	2015	**2016**	2015
Interest	**1,436**	1,472	**2,633**	3,159
Taxes	**-**	(162)	**-**	(162)

10.Contingency

In May 2009, a statement of claim was filed against Freehold for $9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, Freehold has assessed the claim and believes the claim has no merit. The claim's outcome is not determinable and therefore no liability has been recorded in the financial statements.

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)
President and 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

Freehold Royalties Ltd.
400, 144 – 4 Avenue SW
Calgary, AB T2P 3N4
t. 403.221.0802
f. 403.221.0888
w. freeholdroyalties.com

The Manager

Rife Resources Management Ltd.
t. 403.221.0800
w. rife.com

Investor Relations

Matt J. Donohue
Manager, Investor Relations
t. 403.221.0833
tf. 888.257.1873
e. mdonohue@rife.com

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

Computershare Trust Company of Canada
600, 530 – 8 Avenue SW
Calgary, AB T2P 3S8
t. 514.982.7555
tf. 800.564.6253
f. 888.453.0330
e. service@computershare.com
w. computershare.com