OPPORTUNITY KNOCKS

Freehold
ROYALTIES LTD.

2015 ANNUAL REPORT

MESSAGE TO SHAREHOLDERS

Freehold had another successful year reaching an all-time high for production, reflecting the execution of our counter cyclical acquisition strategy. Offsetting this, sustained weakness in crude oil prices reduced Freehold's cash flows significantly.

Sustainability of the underlying business remains our key objective

With crude oil prices at 10-year lows, Freehold's strategy has shifted from one that has historically focused on yielding a blend of income and growth to one focused primarily on preservation of our balance sheet and ensuring sustainability. Through the year, we reduced our monthly dividend twice in order to fulfill this mandate and with a year-end trailing debt to funds from operations at 1.4 times, we feel we have positioned ourselves as a sustainable income option for our shareholders.

Counter cyclical acquirer

Freehold executed its busiest year of acquisitions in its history, completing greater than $400 million in transactions. Highlights included a corporate acquisition that significantly reduced Freehold's future tax expense and two royalty deals that mitigated Freehold's production decline and provided visibility on royalty barrels for the next seven years. Freehold also completed our second largest deal to date, a $318 million royalty transaction, providing a new core area (Viking Dodsland) and multi-years of future royalty drilling. Through these transactions we have exercised considerable flexibility while remaining opportunistic.

EFFECTIVELY MANAGE &
GROW ASSETS
TO DELIVER
LONG-TERM RETURNS

POSITIONED AS A
SUSTAINABLE
INCOME OPTION
FOR SHAREHOLDERS

GREATER THAN
$400 MILLION
IN TRANSACTIONS

"Throughout commodity price cycles, our strategy remains consistent"

RECORD PRODUCTION
AVERAGING
10,945 BOE/D

19% GROWTH
IN PRODUCTION

MAINTAINING A
CONSERVATIVE
DEBT STRATEGY

Continued gains in operations

Freehold achieved record production through 2015 with volumes averaging 10,945 boe per day, 19% growth versus 2014. Both production and drilling within core areas of our portfolio have remained resilient, reflecting the quality of our underlying asset base.

Maintaining financial flexibility

With continued uncertainty in the commodity price environment, maintaining a conservative debt strategy remains a key objective for Freehold. We exited 2015 with year-end net debt of $147 million, implying 1.4 debt to trailing funds from operations. With over $100 million in available capital through our existing bank line, we feel we are advantageously positioned for sustained weakness in oil prices.

Outlook

Throughout commodity price cycles, our strategy remains consistent. Freehold strives to provide shareholders with a low risk, income vehicle with long term upside to commodity prices. With modest capital requirements and high margin royalty barrels, we provide investors with a sustainable yield investment. Our underlying strategy remains fiscally conservative. On March 3, 2016 we reduced our monthly dividend from $0.07 to $0.04 per share, reflecting the current weakness in crude oil prices. We will continue to monitor our revenues and will adjust our dividend to match free cash flows while maintaining a conservative balance sheet.

Thomas J. Mullane
President & Chief Executive Officer

2015 PERFORMANCE **HIGHLIGHTS**

In 2015, Freehold was able to achieve strong growth in its royalty portfolio, reflecting the quality of our underlying asset base and execution of our acquisition strategy. However, sustained weakness in commodity prices significantly reduced our funds from operations and the level of dividends we have historically been able to provide our shareholders.

	Year ended December 31		
($000s except as noted)	2015	2014	change
Financial Highlights			
Gross revenue	135,664	199,850	-32%
Net income (loss)	(4,080)	66,447	-106%
Per share, basic and diluted ($)	(0.05)	0.94	-105%
Funds from operations	103,820	138,447	-25%
Per share ($)	1.15	1.95	-41%
Capital expenditures	22,295	33,701	-34%
Acquisitions	411,352	248,274	66%
Net debt obligations	146,949	135,810	8%
Dividends declared	90,139	119,788	-25%
Per share ($)	1.00	1.68	-40%
Average shares outstanding (000s)	90,505	71,029	27%
Shares outstanding at year-end (000s)	98,940	74,919	32%
Operational Highlights			
Average daily production (boe/d)	10,945	9,180	19%
Average realized price ($/boe)	33.20	58.91	-44%
Operating netback ($/boe)	28.83	52.30	-45%

THE ROYALTY **ADVANTAGE**

We are Different than Your Typical E&P

What differentiates Freehold from other E&P producers is that the majority of our cash flows are derived from royalty assets. With modest capital requirements and high netbacks, the royalty model offers a low risk way to realize upside in commodity prices. At Freehold, our strategy remains centred on growing our cash flows and delivering this to our shareholders.

A Defensive Alternative in Uncertain Times

Because Freehold generates strong margins we provide a defensive alternative, particularly during periods of weakness within the commodity price environment. Our capital program continues to represent a modest percentage of our cash flows with long-term sustainability a key mandate behind our business model.

Mineral Title is Forever

Freehold maintains one of the largest inventories of mineral title acreage outside of the Crown within Canada. A key advantage of owning mineral title is that Freehold owns the acreage in perpetuity, offering an unrivalled time horizon for return on investment.

Diversity, Long Term Option Value within the Portfolio

Assets spanning five provinces and production from over 36,000 well bores allows Freehold income diversity. We receive royalties from over 200 industry operators and our top 10 payors represent 50% of total royalty revenue further mitigating counter-party risk. We estimate we have over eight years of free drilling on our lands under historical drilling trends, offering long term option value for our shareholders.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) was prepared as of March 3, 2016, and is management's opinion about the consolidated operating and financial results of Freehold Royalties Ltd. and its wholly-owned subsidiaries (Freehold or the Company) for the year ended December 31, 2015 and previous periods, and the outlook for Freehold based on information available as of the date hereof.

The financial information contained herein was based on information in the consolidated financial statements, which have been 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 years ended December 31, 2015 and 2014, and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This MD&A should be read in conjunction with the audited financial statements and notes.

This MD&A contains additional GAAP measures, non-GAAP 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 Additional GAAP Measures, Non-GAAP Financial Measures and Forward-Looking Statements included at the end of this MD&A.

MD&A CONTENTS

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. The Company resulted from the reorganization of Freehold Royalty Trust effective December 31, 2010. 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 3.7 million gross acres, greater than 90% of which are royalties. Of this, our mineral title lands (including royalty assumption lands), which we own in perpetuity, cover more than 750,000 acres. In addition, we have gross overriding royalty interests in over 2.5 million acres.

We have interests in more than 36,000 wells (of which over 34,000 are royalty wells including over 18,000 unitized wells). We receive royalty income from over 200 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 (87% in 2015) 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 300,000 gross undeveloped acres.

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.

2015 Highlights

Continued weakness in commodity prices affected Freehold through 2015. Overall, the company saw a significant reduction in revenues, funds from operations and dividends as a result of weak oil prices. Despite commodity pressures, Freehold was able to achieve growth in production within its royalty portfolio, a testament to the quality of our asset base and the success of our acquisition program. Moving forward, we expect our core strategy to remain consistent. We remain advantageously positioned to weather continued weakness in oil prices.

Annual Highlights

($000s, except as noted)	2015	2014	2013
Gross revenue	135,664	199,850	181,578
Revenue, net of royalty expense	133,367	194,184	175,200
Net income (loss)	(4,080)	66,447	57,852
Per share, basic and diluted ($)	(0.05)	0.94	0.86
Funds from operations [(1)]	103,820	138,447	119,431
Per share ($) [(1)]	1.15	1.95	1.79
Total assets	939,394	653,277	427,865
Long-term debt	152,000	139,000	49,000
Total long-term liabilities	179,826	205,447	111,663
Dividends declared	90,139	119,788	112,495
Per share ($) [(2)]	1.00	1.68	1.68
Weighted average shares outstanding, basic (000s)	90,505	71,029	66,900
Shares outstanding at year-end (000s)	98,940	74,919	67,746

(1) See Additional GAAP Measures.

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

Outlook

Business Environment

2015 was a challenging year for E&P producers within Canada, primarily stemming from sustained lower for longer weakness in commodity prices. On the oil side, OPEC's announcement in late 2014 that they would not cut production in the face of weaker supply/demand fundamentals continued to negatively impact prices through the year. However, 2015 highlighted further headwinds relating to drivers such as an oversupplied North American market, demand concerns globally - particularly within historical growth engines China and India - along with a lack of a clear strategy within OPEC. Natural gas prices continued to be negatively impacted by prevailing oversupply issues. Despite sustained weakness in pricing, the North American natural gas market has seen the emergence of plays such as the Utica, Marcellus and Montney adding an oversupply of inventories which has kept prices depressed.

Through 2015 the benchmark WTI crude oil price averaged US$48.80/bbl, down 48% when compared to 2014. Within Canada, oil and gas producers have been protected somewhat from depressed prices by prevailing weakness in the Canadian dollar with the US$/Cdn$ exchange rate averaging $0.78 for 2015, a 14% decrease versus 2014. Through 2015, the price of Edmonton Par averaged $57.20/bbl, a 40% decline over 2014. Heavy oil prices and producers were some of the most negatively impacted through 2015 with Western Canadian Select (WCS) prices averaging $44.81/bbl, down 45% when compared to 2014. AECO prices followed the path set by crude oil averaging $2.77/mcf in 2015, a 37% reduction when compared to last year.

Looking forward, the first half of 2016 is expected to generate little in the way of catalysts for upward momentum in oil prices. This is driven by a combination of an oversupplied market within North America, continued concerns around global demand and sustained relative strength in the U.S. dollar. Recently, increased speculation around proposed production quotas between members of OPEC have increased volatility surrounding prices. We expect the market to remain susceptible to large price swings until there is further visibility on what OPEC's strategy will be moving forward. Moving into the back half of the year, a potential recovery in prices will be driven by a supply-led push with U.S. production being the key driver behind any rebalancing. On the natural gas side, we expect prices, particularly AECO, to remain challenged during 2016. Growth within U.S. shale plays (Marcellus, Utica) continues to displace Canadian volumes. Until there is a viable solution to exporting production off North America, it is expected prices will remain depressed.

Drilling Activity

In 2015, a total of 5,292 wells were drilled and completed within the Western Canadian Sedimentary Basin, down materially from 11,534 in 2014. In November, the Canadian Association of Oilwell Drilling Contractors (CAODC) released its 2016 drilling forecast. The group is currently projecting 4,728 wells drilled through 2016, representing a 59% and 11% decline versus 2014 and 2015 respectively.

Including drilling activity associated with acquisitions, activity levels on Freehold's royalty lands through 2015 increased 25% on a net basis versus last year. Given the diversity of our asset base, drilling activity on our lands typically mirrors activity within Western Canada, however we have seen continued strength in activity in southeast Saskatchewan and the Viking Dodsland.

2016 Guidance Update

The table below summarizes our key operating assumptions for 2016.

- Despite lower spending on our working interest and royalty lands, we have not revised our 2016 production forecast (9,800 boe/d). Volumes are expected to be weighted approximately 62% oil and natural gas liquids (NGLs) and 38% natural gas. We continue to maintain our royalty focus with royalty production accounting for 78% of forecasted 2016 production and 94% of operating income.
- Continuing negative momentum in the commodity environment has resulted in a downward revision to our price assumptions. Through 2016, we are now forecasting WTI and WCS prices to average US$35.00/bbl and $31.00/bbl, respectively (previously US$50.00/bbl and $47.00/bbl). Our AECO natural gas price assumption has also been revised downwards to $2.00/mcf (previously $2.75/mcf).
- The Canadian/U.S. exchange rate has been adjusted downwards to $0.72 (previously $0.76), reflecting the recent declining valuation of the Canadian dollar relative to the United States dollar.
- Operating costs have been reduced to $4.75/boe from $5.00/boe representing an increasing portion of our production coming from royalties, which have no operating costs.
- We have revised our general and administration expense to $2.65/boe from $2.85/boe, as a result of cost reduction initiatives.
- Our capital spending budget has been reduced from $15 million to $7 million reflecting the weaker commodity outlook. A large percentage of our capital expenditures program is non-operated and the exact capital is difficult to predict. We expect to have additional information on the spending of our partners as we move through the year.

2016 Key Operating Assumptions

		Guidance Dated	
2016 Annual Average		Mar. 3, 2016	Nov. 12, 2015
Daily production	boe/d	9,800	9,800
WTI oil price	US$/bbl	35.00	50.00
Western Canadian Select (WCS)	Cdn$/bbl	31.00	47.00
AECO natural gas price	Cdn$/Mcf	2.00	2.75
Exchange rate	Cdn$/US$	0.72	0.76
Operating costs	$/boe	4.75	5.00
General and administrative costs (1)	$/boe	2.65	2.85
Capital expenditures	$ millions	7	15
Dividends paid in shares (DRIP) (2)	$ millions	8	13
Weighted average shares outstanding	millions	100	100

(1) Excludes share based and other compensation.
(2) Assumes an average 15% participation rate in Freehold's dividend reinvestment plan, which is subject to change at the participants' discretion.

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.

A sensitivity analysis of the potential impact of key variables on funds from operations per share is provided below. For the purposes of the sensitivity analysis, the effect of a change in a particular variable is calculated independently of any change in another variable. In reality, changes in one factor will contribute to changes in another, which can magnify or counteract the sensitivities. For instance, trends have shown a correlation between the movement in the foreign exchange rate of the Canadian dollar relative to the U.S. dollar and the benchmark WTI crude oil price.

2016 Sensitivity Analysis

Variable [1]	Change (+/-)	Estimated Change in Funds from Operations ($/share) [2]
WTI oil price	US$1.00/bbl	0.03
Canadian/U.S. dollar exchange rate	US$0.01	0.01
Edmonton Par/WCS differential	Cdn$1.00/bbl	0.01
AECO natural gas price	Cdn$0.25/Mcf	0.02
Interest rate	1%	0.02
Oil and NGL production	100 bbls/d	0.01
Natural gas production	1,000 Mcf/d	0.01

(1) Calculations are performed independently and may not be indicative of actual results that would occur when multiple variables change at the same time.
(2) See Additional GAAP Measures.

Change to Dividend

We have revised our monthly dividend from $0.07 to $0.04/share to be paid on April 15, 2016 to shareholders of record on March 31, 2016. The dividend reduction aligns with a lower for longer commodity outlook. Freehold's goal is not to pay dividends with debt, thus maintaining strength within our balance sheet and ensuring the long term success of our business model. Freehold will continue to evaluate dividend levels on a quarterly basis, with the expectation to increase dividend levels as funds from operations improve.

Based on our current guidance and commodity price assumptions, and assuming no significant changes in the current business environment, we expect to maintain the current monthly dividend rate of $0.04/share through 2016, subject to the Board's quarterly review and approval (see Dividend Policy).

Quarterly Performance

Fourth Quarter Highlights

Freehold delivered strong operational results in the fourth quarter of 2015. Some of the highlights included:

- Production for Q4-2015 averaged 11,815 boe/d, a 20% increase over Q4-2014 and a 5% increase over Q3-2015.
- Royalties accounted for 89% of operating income and 78% of production, reinforcing our royalty focus.
- Royalty production was up 26% compared to Q4-2014 averaging 9,249 boe/d. Growth in volumes was associated with a combination of production acquired through the year, new production from drilling on our royalty lands and a strong quarter from our audit function, including compensatory royalties on our mineral title lands, largely responsible for approximately 500 boe/d of prior period adjustments.
- Working interest production averaged 2,566 boe/d for the quarter, up 2% when compared to the same period last year.
- Funds from operations totalled $25.5 million ($0.26/share) in Q4-2015, down 17% from the same period last year owing to continued weakness in oil and natural gas prices.

- Though average commodity price realizations decreased 36% reduced revenues were partly offset by the increase in production volumes, resulting in a 22% decrease in gross revenue compared to Q4-2014.
- Q4-2015 net loss was $7.4 million (Q4-2014 net income $11.1 million) primarily due to a non-cash impairment charge of $8.0 million in our southeast Saskatchewan working interest area, as a result of the continued drop in expected future commodity prices. Lower revenues and higher depletion and depreciation also contributed to the difference.
- Dividends declared for Q4-2015 totalled $0.21 per share, down from $0.42 per share one year ago due to the reduction in funds from operations resulting from lower commodity prices.
- Average participation in our dividend reinvestment plan (DRIP) was 13% (Q4-2014 – 35%). DRIP proceeds for 2015 totalled $17.2 million.
- Net capital expenditures on our working interest properties totalled $5.6 million over the quarter.
- Basic payout ratio (dividends declared/funds from operations) for 2015 totalled 87% while the adjusted payout ratio (cash dividends plus capital expenditures/funds from operations) for the same period was 95%.
- At December 31, 2015, net debt totalled $146.9 million, down $2.1 million from $149.0 million at September 30, 2015. This implies a net debt to 12-month trailing funds from operations ratio of 1.4 times (excluding the proforma effects of acquisitions).

2015 Performance Compared to Guidance

Compared to our November guidance:

- Average production for the year was 345 boe/d higher, driven by growth in our royalty portfolio and increased prior period adjustments during Q4-2015. Compared to our May 14th guidance, production was 145 boe/d higher than forecast.
- Average oil prices, both for WTI and WCS were slightly below our forecasts as prices retreated through the fourth quarter. This was offset somewhat by a weaker Cdn$/US$ exchange rate.
- Operating costs were slightly better than forecast as royalty barrels as a percentage of total production were higher than forecasted (have no operating costs).
- Capital expenditures totaled $22 million versus guidance of $25 million reflecting slower industry activity (majority of our working interest program is non-operated).

2015 Key Operating Assumptions

		2015 Actual	Previous Guidance				
2015 Annual Average		**Results**	Nov. 12, 2015	Aug. 6, 2015	May 14, 2015	Mar. 5, 2015	Jan. 14, 2015
Daily production	boe/d	**10,945**	10,600	10,400	10,800	9,800	9,800
WTI oil price	US$/bbl	**48.80**	50.00	51.00	60.00	60.00	60.00
Western Canadian Select (WCS)	Cdn$/bbl	**44.81**	46.00	48.00	56.00	56.00	54.00
AECO natural gas price	Cdn$/Mcf	**2.77**	2.75	2.85	2.75	3.00	3.00
Exchange rate	Cdn$/US$	**0.78**	0.79	0.79	0.82	0.80	0.84
Operating costs	$/boe	**4.56**	4.75	5.00	5.25	6.60	6.60
General and administrative costs (1)	$/boe	**2.66**	2.60	2.50	2.60	2.60	2.60
Capital expenditures	$ millions	**22**	25	20	25	25	25
Dividends paid in shares (DRIP)	$ millions	**17**	17	16	27	26	26
Weighted average shares outstanding	millions	**91**	91	91	91	76	76

(1) Excludes share based and other compensation.

Quarterly Trends

Quarterly variances in revenues, net income 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 seasonal 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 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:

- OPEC decided in late 2014 to maintain production despite signs of increasing supply. The decision to keep production at existing levels resulted in a material retreat in worldwide crude oil prices with prices remaining weak through 2015.
- 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 are still affected 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 and through 2015 resulted in a change to our monthly dividend from $0.14 to $0.09 in Q1-2015 and from $0.09 to $0.07 in Q3-2015.
- 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 $660 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

	2015				2014			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial ($000s, except as noted)								
Revenue, net of royalty expense	33,728	35,391	37,222	27,026	42,597	50,625	52,793	48,169
Dividends declared	20,747	24,604	24,459	20,329	31,353	31,148	28,711	28,576
Per share ($) (1)	0.21	0.25	0.27	0.27	0.42	0.42	0.42	0.42
Net income (loss)	(7,423)	(22,193)	3,919	21,617	11,082	17,913	19,598	17,854
Per share, basic and diluted ($)	(0.08)	(0.23)	0.04	0.29	0.15	0.24	0.29	0.26
Funds from operations (2)	25,509	27,643	28,730	21,938	30,774	39,561	37,319	30,793
Per share, basic ($) (2)	0.26	0.28	0.32	0.29	0.41	0.54	0.55	0.45
Operating Income (2)	29,186	30,601	32,733	22,632	37,584	46,012	47,801	43,795
Operating income from royalties (%)	89	90	85	83	80	78	77	77
Dividends paid in shares (DRIP)	2,758	3,708	2,398	8,361	10,915	6,170	7,588	7,591
Average DRIP participation rate (%) (3)	13	14	11	35	35	20	26	27
Acquisitions	(143)	815	342,310	68,370	60,566	76,780	109,044	1,884
Capital expenditures	5,607	7,969	2,750	5,969	13,500	2,811	6,284	11,106
Net debt obligations (2)	146,949	148,994	146,992	198,834	135,810	122,091	160,061	48,600
Shares outstanding								
Weighted average, basic (000s)	98,731	98,357	89,388	75,199	74,545	73,214	68,296	67,965
At quarter end (000s)	98,940	98,599	98,203	75,457	74,919	74,286	68,520	68,157
Operating ($/boe, except as noted)								
Daily production (boe/d) (4)	11,815	11,266	10,617	10,058	9,836	9,430	8,810	8,623
Royalty interest (%)	78	78	76	71	74	75	74	74
Average selling price	30.34	34.11	38.63	29.80	47.46	59.54	67.45	62.72
Operating netback (2)	26.85	29.52	33.88	25.01	41.54	53.03	59.62	56.43
Operating expenses	4.18	4.62	4.65	4.85	5.54	5.32	6.23	5.64
Working interest properties	19.24	20.78	19.14	16.87	21.66	21.05	23.61	21.40
Net general and administrative expenses (5)	2.23	2.33	2.34	3.92	2.32	2.16	2.36	3.62
Benchmark Prices								
WTI crude oil (US$/bbl)	42.18	46.43	57.94	48.64	73.15	97.15	102.99	98.68
Exchange rate (US$/Cdn$)	0.75	0.76	0.81	0.81	0.88	0.92	0.92	0.91
Edmonton Par crude oil (Cdn$/bbl)	52.89	56.23	67.75	51.95	75.79	97.10	105.70	99.73
Western Canadian Select (WCS) (Cdn$/bbl)	36.86	43.29	56.97	42.14	66.74	83.82	90.44	83.40
AECO natural gas (Cdn$/Mcf)	2.65	2.80	2.67	2.95	4.01	4.22	4.68	4.75
Share Trading Performance								
High ($)	13.52	16.07	19.04	20.62	23.27	26.92	28.15	23.47
Low ($)	9.00	8.73	15.86	16.14	17.02	22.64	23.01	21.41
Close ($)	10.86	10.82	16.14	17.94	19.12	23.16	26.78	23.28
Volume (000s)	19,312	22,753	18,912	14,297	18,607	10,412	7,232	7,322

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

Revenues

Production

As we hold primarily small royalty interests in over 34,000 wells, obtaining timely production data is extremely difficult. Thus, 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, and our audit program, our reported royalty volumes usually include adjustments for prior periods.

Our production was up significantly in 2015 (19%) due primarily to volumes added through acquisitions and the strength of our audit function. Royalty interests comprised 76% of total production in 2015, up from 74% in 2014, as we have added more royalty volumes through acquisitions. Our production mix for 2015 was 38% natural gas, 20% heavy oil, 37% light and medium oil, and 5% NGLs. Our oil production has become lighter in 2015 as a result of our recent acquisitions, which have generally been of a lighter quality crude oil.

In total, working interest production averaged 11% higher than 2014. Increased volumes were as a result of our corporate acquisition of Anderson Energy early in the year, which added approximately 320 boe/d of working interest volumes.

Production Summary (1)

(boe/d)	2015	2014	Change
Royalty interest	8,310	6,805	22%
Working interest	2,635	2,375	11%
Total	10,945	9,180	19%

(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.

Average Daily Production by Product Type

	2015	2014	Change
Light and medium oil (bbls/d)	3,956	2,986	32%
Heavy oil (bbls/d)	2,220	2,249	-1%
NGL (bbls/d)	581	537	8%
Total oil and NGL (bbls/d)	6,757	5,772	17%
Natural gas (Mcf/d)	25,123	20,446	23%
Oil equivalent (boe/d)	10,945	9,180	19%
Total annual production (Mboe)	3,995	3,350	19%
Potash (tonnes/d)	8	7	14%

Product Prices

The following table is a summary of average benchmark prices.

Average Benchmark Prices

	2015	2014	Change
WTI crude oil (US$/bbl)	**48.80**	92.99	-48%
Exchange rate (US$/Cdn$)	**0.78**	0.91	-14%
Edmonton Par crude oil (Cdn$/bbl)	**57.20**	94.58	-40%
Western Canadian Select (Cdn$/bbl)	**44.81**	81.10	-45%
WTI/Edmonton Par differential ($/bbl)	**8.40**	1.59	428%
Edmonton Par/WCS differential (Cdn$/bbl)	**(12.39)**	(13.48)	-8%
AECO natural gas (Cdn$/Mcf)	**2.77**	4.41	-37%

The price we receive for our oil production is primarily driven by the U.S. dollar price of West Texas Intermediate (WTI). Therefore, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenue received. Approximately 20% of our total production is heavy crude, which trades at a discount to light crude. As a result of recent acquisitions of lighter quality crude oil, our oil production is now receiving, on average, a slight premium to the benchmark Western Canadian Select (WCS) heavy oil stream, which has an average API gravity of 20.5 degrees.

Our average selling prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average selling price was 44% lower in 2015 reflecting weakness across crude oil (WTI/Edmonton Par/WCS) and AECO natural gas, offset slightly by weakness in the US$/Cdn$ exchange rate.

Average Selling Prices

	2015	2014	Change
Oil ($/bbl)	**47.00**	81.93	-43%
NGL ($/bbl)	**27.14**	58.34	-53%
Oil and NGL ($/bbl)	**45.29**	79.74	-43%
Natural gas ($/Mcf)	**2.28**	3.94	-42%
Oil equivalent ($/boe)	**33.20**	58.91	-44%
Potash ($/tonne)	**416.86**	341.02	22%

Marketing and Hedging

Our production remained unhedged in 2015. Hedging is monitored and considered on an ongoing basis and is reviewed quarterly by the Board.

Royalty Interests

Our royalty lands consist of a large number of properties with generally small volumes per property. A provision of most leases calls for our natural gas to be marketed with the lessees' production. Some of our leases allow us to take our oil production in-kind. In 2015 we marketed approximately 10% of our royalty oil production using 30-day contracts.

Working Interests

We market most of our working interest oil production using 30-day contracts to ensure competitive pricing. In 2015 approximately 50% of our working interest natural gas production was sold under marketing arrangements tied to the Alberta monthly or daily spot price (AECO) or other indexed referenced prices, and the balance was marketed with the operators' production.

Gross Revenue

Gross revenue in 2015 was 32% lower than in 2014 largely due to lower realized pricing. On the royalty side, revenues decreased by a lesser amount (27%) as decreases in pricing was offset by increased production volumes.

($000s)	2015	2014	Change
Royalty interest revenue			
Oil	76,135	100,835	-24%
NGL	4,671	9,342	-50%
Natural gas	16,735	25,237	-34%
Other (1)	2,394	1,835	30%
	99,935	137,249	-27%
Working interest revenue			
Oil	29,828	55,698	-46%
NGL	1,079	2,075	-48%
Natural gas	4,182	4,159	1%
Other (1)	640	669	-4%
	35,729	62,601	-43%
Total gross revenue			
Oil	105,963	156,533	-32%
NGL	5,750	11,417	-50%
Natural gas	20,917	29,396	-29%
Other (1)	3,034	2,504	21%
	135,664	199,850	-32%

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

The accompanying table demonstrates the net effect of price and volume variances on gross revenue. Weakness in both oil and natural gas prices accounted for the bulk of the negative variance in 2015, but this was offset partially by our increased production.

Gross Revenue Variances

($000s)	2015 vs. 2014	2014 vs. 2013
Oil and NGL		
Production increase	16,316	1,442
Price increase (decrease)	(72,553)	5,185
Net increase (decrease)	(56,237)	6,627
Natural gas		
Production increase	3,892	1,869
Price increase (decrease)	(12,371)	9,730
Net increase (decrease)	(8,479)	11,599
Other (1)	530	46
Gross revenue increase (decrease)	(64,186)	18,272

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

Other Income

During 2015 Freehold recognized $0.8 million of other income as a result of a settlement with Canpar Holdings Ltd. on certain lands where both companies have a mineral title interest (see Related Party Transactions).

Expenses

Royalty Expense and Mineral Taxes

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.

We do not incur royalty expense on production from our royalty interest lands, other than minor freehold mineral taxes. As the royalty owner, we receive the royalty as income from other companies. Royalty expense on working interest properties dropped by 59% largely due to the decrease in commodity prices. Mineral tax, payable on some of our royalty interests, decreased by 61%, as 2014 had approximately $0.3 million for a one-time adjustment for prior periods.

Royalty Expense (1)

($000s, except as noted)	2015	2014	Change
Working interest	2,109	5,184	-59%
Per boe ($)	2.19	5.98	-63%
Royalty interest	188	482	-61%
Per boe ($)	0.06	0.19	-68%
Total	2,297	5,666	-59%
Per boe ($)	0.57	1.69	-66%

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

Operating Expenses

Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas, and NGL production. Overhead recoveries associated with operated properties are included in operating expenses and accounted for as a reduction to general and administrative (G&A) expenses. A percentage of operating expense is fixed and, as such, per boe operating expenses are highly variable to production volumes.

On a total production per boe basis, operating expense decreased 20% in 2015, largely due an increase in our percentage of production from royalties, which have no operating expense. Decreases of 14% on a working interest per boe basis were largely a result of a strong trending down in industry costs.

Operating Expenses

($000s, except as noted)	2015	2014	Change
Working interest	**18,215**	18,992	-4%
Per boe ($)	**18.94**	21.92	-14%
Royalty interest (1)	-	-	-
Per boe ($)	-	-	-
Total operating expenses	**18,215**	18,992	-4%
Per boe ($)	**4.56**	5.67	-20%

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

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 following tables demonstrate the advantage of our royalty lands, which have no operating or royalty expenses other than minor freehold mineral taxes. Royalty interests accounted for 74% of gross revenue in 2015, but contributed 87% of operating income.

2015 Operating Income

($000s)	Royalty Interest	Working Interest	Total
Gross revenue (1)	99,935	35,729	**135,664**
Royalty expense (2)	(188)	(2,109)	**(2,297)**
Net revenue	99,747	33,620	**133,367**
Operating expense	-	(18,215)	**(18,215)**
Operating income	99,747	15,405	**115,152**
Percentage by category	87%	13%	**100%**

(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.

2015 Operating Netback

($ per boe)	Royalty Interest	Working Interest	Total
Gross revenue (1)	32.95	37.15	**33.96**
Royalty expense (2)	(0.06)	(2.19)	**(0.57)**
Net revenue	32.89	34.96	**33.39**
Operating expense	-	(18.94)	**(4.56)**
Operating netback (3)	32.89	16.02	**28.83**

(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.

2015 vs. 2014 Operating Netback

($ per boe)	2015	2014	Change
Royalty interest	32.89	55.07	-40%
Working interest	16.02	44.35	-64%
Total	28.83	52.30	-45%

General and Administrative Expenses

We have significant land administration, accounting and auditing requirements to administer and collect royalty payments, including systems to track development activity on the royalty lands. General and administrative (G&A) expenses include direct costs and reimbursement of G&A expenses incurred by Rife Resources Management Ltd. (the Manager) on behalf of Freehold (see Related Party Transactions).

In 2015, on a total dollar basis, G&A expenses were up 22% primarily the result of acquisitions. However, on a per boe basis costs were consistent with last year due to the extra production volumes we added through the acquisitions.

General and Administrative Expenses

($000s, except as noted)	2015	2014	Change
Gross general and administrative expenses	12,299	10,055	22%
Less: capitalized and overhead recoveries	(1,656)	(1,376)	20%
Net general and administrative expenses	10,643	8,679	23%
Per boe ($)	2.66	2.59	3%

Management Fees

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 the DRIP and equity offerings resulted in pro-rata increases in the number of shares issued as the management fee (see Shareholders' Capital). This agreement was recently amended on November 9, 2015 (filed on SEDAR). The new amended and restated management agreement caps the management fee at 71,912 shares per quarter for 2016 and requires a reduction of shares in future years. The equity offering in May 2015 done in conjunction with our major royalty acquisition was largely the cause of the 31% increase in shares issued as part of the management fee. However, as a result of a reduced share price, the ascribed value associated with the management fee was down 22% compared to 2014.

Management Fees (paid in shares)

	2015	2014	Change
Shares issued in payment of management fees	269,978	206,280	31%
Ascribed value ($000s) [1]	3,693	4,743	-22%
Per boe ($)	0.92	1.42	-35%

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

Share Based and Other Compensation

Long-Term Incentive Plan

We are responsible for funding a portion of the long-term incentive compensation plan (the LTIP) for employees of the Manager. The 2012 LTIP grants vested in the first quarter of 2015 and $0.5 million of share based compensation was paid out. The 2011 LTIP grants vested in the first quarter of 2014 and $1.0 million was paid out. In 2015 there was only $0.1 million of net LTIP expense largely because of a decrease in Freehold's share price.

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. Dividends declared prior to redemption are assumed to be reinvested in notional share units on the dividend payment date.

For the year-end December 31, 2015, no DSUs were redeemed. For the year-end December 31, 2014, 14,414 DSUs were redeemed, resulting in the issuance of 10,090 shares from treasury. In payment of withholding tax, 4,324 were cancelled and the cash value of $0.1 million was remitted to Canada Revenue Agency. In January 2016 a retired director redeemed 37,628 DSUs, resulting in the issuance of 26,340 shares from treasury. In payment of withholding tax, 11,288 DSUs were cancelled and the cash value of $0.1 million was remitted to Canada Revenue Agency. As at December 31, 2015, there were 177,012 deferred share units outstanding, and as at March 3, 2016, there were 183,451 deferred share units outstanding.

Retirement Benefit Plan

Freehold pays its proportionate share of a retirement benefit for certain former employees of the Manager. The retirement benefit is payable in four equal instalments upon retirement. Service costs are amortized on a straight-line basis over the expected average remaining service lifetime.

Share Based and Other Compensation

($000s, except as noted)	**2015**	2014	Change
Gross LTIP	**61**	(354)	-117%
Less: capitalized portion	**(11)**	63	-117%
Net LTIP	**50**	(291)	-117%
Deferred share unit plan	**705**	680	4%
Retirement benefit	**11**	49	-78%
Share based and other compensation	**766**	438	75%
Per boe ($)	**0.19**	0.13	46%

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.

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. This agreement was recently amended on November 9, 2015. The new amended and restated management agreement caps the management fee at 71,912 shares per quarter for 2016 and requires a reduction of shares in future years. For the year ended December 31, 2015, Freehold issued 269,978 shares (2014 – 206,280) as a management fee to the Manager pursuant to the management agreement. The ascribed value of $3.7 million (2014 – $4.7 million) was based on the closing price of the shares on the last trading day of each quarter.

For the year ended December 31, 2015, the Manager charged $9.0 million in general and administrative costs (2014 – $7.5 million). At December 31, 2014, there was $0.7 million (2014 – $0.5 million) in accounts payable and accrued liabilities relating to these costs.

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 December 31, 2015, there was $nil (2014 - $0.3 million) in accounts payable and accrued liabilities relating to these transactions. In addition, Freehold receives royalties from Rife pursuant to various royalty agreements. For the year ended December 31, 2015, Freehold received royalties of approximately $1.5 million (2014 – $2.2 million). At December 31, 2015, there was $0.1 million (2014 - $0.2 million) in accounts receivable relating to these transactions. On November 27, 2014, Freehold acquired royalty interests in Soda Lake Saskatchewan and Lindbergh Alberta for $10.1 million from Rife, including adjustments.

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. 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.

Freehold and Canpar have evaluated certain of these royalty interests where, among other factors, the identification of the reservoir formation was not straight forward and therefore ultimate ownership of the royalty interest wells was uncertain between Freehold and Canpar. An ongoing project relating to these interests was completed during the year whereby a one-time settlement was reached and Freehold recognized $0.8 million of other income.

At December 31, 2015, there was $nil (2014 – $nil) in accounts receivable and accounts payable and accrued liabilities relating to transactions with Canpar.

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. In addition, concurrent with the closing of the bought deal equity offering on July 16, 2014, CN Pension Trust Funds invested approximately $15 million in Freehold through the purchase of 557,621 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.

Expenses relating to compensation for key management personnel, considered to be Freehold's Board of Directors and Senior Management, are as follows:

Key Management Personnel Compensation

($000s)	December 31 2015	December 31 2014
Short-term benefits (including employee wages and directors fees)	1,346	1,208
Share based compensation	723	580
Total	2,069	1,788

Interest and Financing

In 2015, interest and financing expense increased due to higher debt levels. The average effective interest rate on advances under our credit facilities during 2015 was 2.9% (2014 – 3.3%).

Interest and Financing

($000s, except as noted)	2015	2014	Change
Interest on operating line or other	-	3	-100%
Interest on long-term debt	5,696	4,402	29%
Interest and financing expense	5,696	4,405	29%
Per boe ($)	1.43	1.31	9%

Depletion and Depreciation

Petroleum and natural gas interests, including the costs of production equipment, future capital costs, estimated decommissioning costs, and directly attributable general and administrative costs, are depleted on the unit-of-production method based on estimated proved plus probable oil and gas reserves (see Critical Accounting Estimates). Reserves are independently evaluated at year-end. For the first three quarters of 2015, the estimate of proved plus probable reserves was based on the independent evaluation dated December 31, 2014, adjusted for acquisitions, development, and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as of December 31, 2015. The increase in depletion from 2014 to 2015 is a result of increased production volumes and ongoing acquisition and capital expenditures.

Depletion and Depreciation

($000s, except as noted)	2015	2014	Change
Depletion and depreciation	95,703	67,145	43%
Per boe ($)	23.96	20.04	20%

Impairment

At December 31, 2015 Freehold tested its two working interest cash generating units (CGUs) for impairment due to the continued drop in expected future commodity prices as recognized by industry reserve evaluators. Freehold estimated the recoverable amount as the value in use based on discounted future net cash flows of proved and probable reserves using forecast prices and costs, discounted at 10% (pre-tax). In determining the discount rate, Freehold considered an estimated industry weighted cost of capital and the resource composition of the assets. The estimate was based on Freehold's December 31, 2015 reserve report. Management recognizes that all assumptions and estimates affecting the value are subject to a high degree of uncertainty.

Freehold recognized a non-cash impairment charge on its Southeast Saskatchewan Working Interest CGU of $8.0 million as the carrying value exceeded the estimated value in use. The Southeast Saskatchewan Working Interest CGU contains all of Freehold's working interest properties in southeast Saskatchewan. The estimated recoverable amount of the Southeast Saskatchewan CGU at December 31, 2015 is $29.1 million. In addition, Freehold recognized a non-cash impairment charge on its Other Working Interest CGU of $30.8 million as the carrying value exceeded the estimated value in use. The Other Working Interest CGU contains Freehold's diverse group of working interest properties outside of the Southeast Saskatchewan Working Interest CGU. The estimated recoverable amount of the Other Working Interest CGU at December 31, 2015 is $54.7 million.

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. In 2015 and 2014 corporate federal and provincial income tax rates for Freehold averaged approximately 26% and 25% respectively.

Freehold's 2015 tax was affected by the corporate acquisition that occurred in the first quarter (see Investing Activities). The transaction created a $55.4 million deferred income tax asset based on approximately $220 million of tax pools and a statutory rate of approximately 25%. The difference between the consideration paid and the net assets acquired resulted in a non-cash accounting gain of $24.3 million.

The deferred tax asset resulting from the corporate acquisition was further adjusted upwards by the change in Alberta's corporate tax rate for future periods to 27% and the tax effect of the impairment charge at 27%. As a result of the above mentioned events, Freehold has a deferred income tax asset of $21.1 million at December 31, 2015 versus a $44.8 million liability at December 31, 2014. The deferred tax recovery in 2015 was $6.4 million (2014 - $0.7 million expense).

As a result of the corporate acquisition Freehold had no current taxes in 2015. The current income tax recovery of $5.1 million was the result of additional deductions for prior tax years made upon actual filing of our tax returns.

Tax Pools

We are entitled to claim certain tax deductions available to all owners of oil and gas properties. Freehold's tax pools grew materially in 2015 primarily associated with acquisition activity. The tax pools below are deductible at various rates.

Tax Pools (1)

($000s)	2015	2014	Change
Canadian oil and gas property expense (10% declining balance)	**668,256**	347,110	93%
Canadian development expense (30% declining balance)	**85,406**	86,215	-1%
Capital cost allowance (generally 25%)	**30,738**	33,659	-9%
Share issue costs	**16,351**	5,830	180%
Non-capital losses	**165,356**	-	-
Total	**966,107**	472,814	104%

(1) These amounts, subject to review by Canada Revenue Agency, represent Freehold's direct tax pools as well as the tax pools of its subsidiaries.

Liquidity and Capital Resources

We define capital as long-term debt, shareholders' equity, and working capital. We manage our capital structure taking into account operating activities, debt levels, debt covenants, capital expenditures, DRIP participation, dividend levels, and taxes, among others. We also consider changes in economic conditions and commodity prices as well as the risk characteristics of our assets. We have a depleting asset base, and ongoing development activities and acquisitions are necessary to replace production and extend reserve life. From time to time, we may issue shares or adjust capital spending to manage current and projected debt levels.

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 issues, payments to royalty owners are often delayed longer. Also, working capital can fluctuate significantly due to volume and price changes at each period end and unpaid capital expenditures. Working capital at December 31, 2015 was up $1.9 million from year-end 2014 as the effects of lower dividends payable and accounts payable and accrued liabilities more than offset the decrease in accounts receivable and current taxes receivable.

Components of Working Capital

	As at December 31		
($000s)	**2015**	2014	Change
Cash	**876**	1,126	-22%
Accounts receivable	**21,046**	26,430	-20%
Current taxes receivable	**73**	2,597	-97%
Current assets	**21,995**	30,153	-27%
Dividends payable	**(6,924)**	(10,488)	-34%
Accounts payable and accrued liabilities	**(9,826)**	(15,864)	-38%
Current portion of share based and other compensation	**(194)**	(611)	-68%
Current liabilities	**(16,944)**	(26,963)	-37%
Working capital	**5,051**	3,190	58%

At December 31, 2015, Freehold has a $245 million extendible revolving term credit facility with a syndicate of four Canadian chartered banks, on which $152 million was drawn. In addition, Freehold has available a $15 million extendible revolving operating facility.

At December 31, 2015 the facilities are secured with $400 million demand 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. The facilities are extendible annually with the latest review completed in May 2015. Freehold's borrowing base is dependent on the lenders annual review and interpretation of Freehold's reserves and future commodity prices, with the next renewal to occur by May 2016. 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.

In 2015, we drew on our credit facilities to partially fund $411 million of acquisitions. Other effects on our net debt obligations included working capital, funds from operations and dividend levels.

Debt Analysis

($000s)	2015	2014	Change
Long-term debt	152,000	139,000	9%
Short-term debt (operating line)	-	-	-
Total debt	152,000	139,000	9%
Working capital	(5,051)	(3,190)	58%
Net debt obligations	146,949	135,810	8%

We are bound by non-financial covenants on our credit facilities and we monitor these monthly to ensure compliance. Under our credit facility, we are restricted from declaring dividends if we are or would be in default under the credit facility or if our borrowings thereunder exceed our borrowing base, which was $260 million at December 31, 2015. As at December 31, 2015, we were in compliance with all such covenants.

Net debt to annual funds from operations was 1.4 times and net debt was 17% of total capitalization at the end of 2015.

Financial Leverage and Coverage Ratios

	2015	2014	Change
Net debt to trailing funds from operations (times)	1.4	1.0	40%
Net debt to dividends (times)	1.6	1.1	45%
Dividends to interest expense (times)	16	27	-41%
Net debt to net debt plus equity (%)	17	24	-29%

Contractual Obligations and Commitments

Our borrowing base is dependent on our lenders' annual 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. If our lenders decide not to extend our credit facilities, we have a contractual obligation to make principal repayments on our long-term debt. Equal quarterly payments would be required in 2017 and 2018 based on the principal outstanding at the time the current agreement expires, which is May 2016. As per the terms of the agreement, the first quarterly payment would commence on January 1, 2017.

Freehold's non-derivative financial liabilities include its dividends payable, accounts payable and accrued liabilities, current taxes payable, share based and other compensation payable and long-term debt. Freehold has no derivative financial liabilities. The following table outlines cash flows associated with contractual maturities of Freehold's non-derivative financial liabilities as at December 31, 2015.

Non-Derivative Financial Liabilities

($000s)	Less than 1 Year	2-3 Years	Total
Dividends payable	6,924	-	6,924
Accounts payable and accrued liabilities	9,826	-	9,826
Share based and other compensation payable	194	191	385
Long-term debt	-	152,000	152,000
Total	16,944	152,191	169,135

Shareholders' Capital

As at December 31, 2015, there were 98,940,152 shares outstanding and as at March 3, 2016, there were 99,141,900 shares outstanding.

On May 6, 2015, Freehold closed a bought deal equity offering, issuing 20,700,000 common shares and a private equity offering to CN Pension Trust Funds (see Related Party Transactions) issuing 1,833,334 common shares, both at a price of $18.00 per share for gross proceeds of $405.6 million. The issue costs including the underwriter fees were $15.4 million ($11.2 million net of a tax effect). The funds were used for the royalty acquisition which closed on the same date and to repay a portion of bank indebtedness.

On July 16, 2014, Freehold closed a bought deal equity offering, issuing 4,900,000 common shares and a private equity offering to CN Pension Trust Funds issuing 557,621 common shares, both at a price of $26.90 per share for gross proceeds of $146.8 million. The issue costs including the underwriter fees were $5.7 million ($4.3 million net of a tax effect).

During 2015, Freehold issued 269,978 shares (2014 – 206,280 shares) for payment of the management fee (see Related Party Transactions).

In 2015, participation in Freehold's DRIP was 18% (2014 – 27%). We issued 1.2 million (2014 – 1.5 million) shares related to the DRIP. The ascribed value of $17.2 million (2014 – $32.3 million) was based on the weighted average closing price for the 10- trading days preceding each payment date.

As at December 31, 2015, there were 177,012 deferred share units (DSUs) outstanding (2014 – 136,455). During 2015 there were no shares issued for redemption of DSUs (2014 – 14,414 redeemed and 10,090 shares issued). On January 1, 2016, the Board granted a total of 41,437 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. In January 2016 a retired director redeemed 37,628 DSUs, resulting in the issuance of 26,340 shares from treasury. As at March 3, 2016, there were 183,451 DSUs outstanding. (See Share Based and Other Compensation)

For the year ended December 31, 2015, Deferred Share Units were excluded from the calculation of diluted net loss per share as their effect was anti-dilutive.

Shares Outstanding

	2015	2014	Change
Weighted average			
Basic	**90,504,786**	71,029,156	27%
Diluted	**90,504,786**	71,170,896	27%
At December 31	**98,940,152**	74,918,711	32%

Dividend Policy

The Board reviews and determines the dividend rate quarterly, or as conditions necessitate, 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.

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the *Business Corporations Act* (Alberta) (ABCA). Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at December 31, 2015, our legal stated capital was $1,032 million (2014– $606 million).

2015 Dividends Declared

Record Date	Payment Date	Dividend Amount ($ per share)
January 31, 2015	February 17, 2015	0.09
February 28, 2015	March 16, 2015	0.09
March 31, 2015	April 15, 2015	0.09
April 30, 2015	May 15, 2015	0.09
May 31, 2015	June 15, 2015	0.09
June 30, 2015	July 15, 2015	0.09
July 31, 2015	August 17, 2014	0.09
August 31, 2015	September 15, 2015	0.09
September 30, 2015	October 15, 2015	0.07
October 31, 2015	November 16, 2015	0.07
November 30, 2015	December 15, 2015	0.07
December 31, 2015	January 15, 2016	0.07
Total		**1.00**

Dividends declared in 2015 totalled $90.1 million ($1.00 per share). From inception of Freehold Royalty Trust in 1996 to December 31, 2015, Freehold distributed $1.4 billion ($29.93 per share) to our shareholders.

Accumulated Dividends

	2015	2014	Change
Dividends declared ($000s)	90,139	119,788	-25%
Accumulated, beginning of year	1,335,832	1,216,044	10%
Accumulated, end of year	1,425,971	1,335,832	7%
Dividends per share ($) (1)	1.00	1.68	-40%
Accumulated, beginning of year	28.93	27.25	6%
Accumulated, end of year	29.93	28.93	3%

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

The amended and restated DRIP allows 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). Registered shareholders who wish to enroll in the DRIP may do so by contacting Computershare Trust Company of Canada, the Plan Agent. Beneficial shareholders who wish to participate in the DRIP should contact the broker or other nominee through which their shares are held to obtain appropriate enrollment instructions, ensuring any deadlines or other requirements that such broker or nominee may impose or be subject to are met. U.S. residents may not participate in the DRIP.

The tables below show reconciliations of funds from operations and dividends. In 2015 Freehold's basic payout ratio was 87% and its adjusted payout ratio was 95%, exhibiting that dividend payments are being made within our means (see Non-GAAP Measures and Additional GAAP Measures).

Dividends Analysis

($000s)	2015	2014	Change
Dividends paid in cash	76,478	86,521	-12%
Dividends paid in shares (DRIP)	17,225	32,264	-47%
Total dividends paid (1)	93,703	118,785	-21%
Dividends declared	90,139	119,788	-25%
Funds from operations	103,820	138,447	-25%
Capital expenditures	22,295	33,701	-34%
Basic payout ratio (2)	87%	87%	0%
Adjusted payout ratio (3)	95%	87%	9%

(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).

Reconciliation of Dividends Declared

($000s)	2015	2014	Change
Funds from operations [1]	103,820	138,447	-25%
Proceeds from the DRIP	17,225	32,264	-47%
Issuance of shares, net of issue costs	390,236	141,085	177%
Debt additions	13,000	90,000	-86%
Acquisition advance	949	(949)	-200%
Acquisitions	(411,352)	(248,274)	66%
Capital expenditures	(22,295)	(33,701)	-34%
Working capital change	(1,444)	916	-258%
Dividends declared	90,139	119,788	-25%

(1) See Additional GAAP Measures.

Investing Activities

Acquisitions

We pursue opportunities to augment our production and reserves, primarily targeting royalty interests. Freehold's acquisition strategy targets individual properties or groups of properties with a focus on royalty interests. The key criteria are:

- quality assets;
- attractive returns;
- acceptable risk profile; and
- long economic life.

In 2015, we completed $411 million (2014 - $248 million) in acquisitions which were funded through an equity issuance and our credit facilities. Highlights through the year included:

- On January 23, 2015 Freehold acquired all of the outstanding shares of Anderson Energy Ltd. (Anderson) pursuant to a plan of arrangement under the ABCA for total consideration of $35 million (subject to certain post-closing adjustments). Pursuant to the plan of arrangement, Anderson shareholders exchanged their shares for shares of a newly formed publicly listed company, Anderson Energy Inc. (New Anderson). In addition, prior to Freehold acquiring the outstanding shares, Anderson transferred certain assets and liabilities to New Anderson. The liabilities transferred to New Anderson included Anderson's liabilities and obligations for its convertible debentures.
- On January 23, 2015 Freehold closed an agreement purchasing producing and non-producing royalty and mineral title assets in Alberta, British Columbia and Saskatchewan for $12.3 million, including adjustments.
- On March 24, 2015 Freehold closed a new royalty acquisition in the Lloydminster area of Alberta for $20.0 million, including adjustments.
- On May 6, 2015, Freehold acquired two royalty packages for $317.5 million, including adjustments. The first royalty package is an 8.5% gross overriding royalty covering certain lands in the Dodsland area of Saskatchewan prospective for the Viking formation. The second package is existing royalties and mineral title lands (including undeveloped land valued at $11.1 million) across a variety of plays within the Western Canadian Sedimentary Basin.
- On June 12, 2015 Freehold closed a new royalty acquisition in the Stolberg, Carsland and Wayne areas of Alberta for $25.0 million, including adjustments.

Capital Expenditures

In 2015, development expenditures of $22.3 million amounted to 21% of funds from operations a 34% reduction from levels spent in 2014. We funded capital expenditures largely from funds from operations.

In the upstream oil and gas sector, because of the nature of reserve reporting, natural reservoir depletion, and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Therefore, maintenance capital is not disclosed separately from development capital spending.

($000s, except as noted)	2015	2014	Change
Development drilling and other	14,121	23,585	-40%
Plant and facilities	8,174	10,116	-19%
Total capital expenditures	22,295	33,701	-34%

Decommissioning Liability

We have no decommissioning liability on our royalty interest properties. Our decommissioning liability results from our responsibility to abandon and reclaim our net share of all working interest properties. The undiscounted value of our total decommissioning liability is estimated to be $40.3 million (2014 – $33.4 million). Payments to settle the obligations are expected to occur continuously over the next 55 years, with the majority being settled within 10 to 20 years. At December 31, 2015, a risk-free rate of 2.2% (2014– 2.3%) and an inflation rate of 1.5% (2014 – 1.5%) were used to calculate the fair value. The value of the decommissioning liability at December 31, 2015 was $27.6 million (2014 – $21.3 million).

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, we have assessed the claim, believe it has no merit, and intend to aggressively defend against the claim. The claim's outcome is not determinable and therefore, no liability has been recorded in the financial statements.

Business Risks and Mitigating Strategies

Our operations are subject to the same industry risks and conditions faced by all oil and gas companies. The most significant of these include the following:

- fluctuations in commodity prices and quality differentials as a result of weather patterns, world and North American market forces or shifts in the balance between supply and demand for crude oil and gas;
- access to pipelines or other transportation methods for bringing oil and natural gas to market;
- variations in currency exchange rates;
- imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves. Our reserves will deplete over time through continued production and we and our industry partners and royalty payors may not be able to replace these reserves on an economic basis;
- reliance on royalty payors to drill and produce on our lands and their ability to pay their obligations;
- industry activity levels and intense competition for land, goods and services, and qualified personnel;
- stock market volatility and the ability to access sufficient capital from internal and external sources;
- risk associated with volatility in global financial markets;
- risk associated with the renegotiation of our credit facility;
- operational or marketing risks resulting in delivery interruptions, delays or unanticipated production declines;
- changes in government regulations, taxation, and royalties; and
- safety and environmental risks.

For a more detailed description of risk factors, please see our Annual Information Form.

We employ the following strategies to mitigate these risks:

- Our diversified revenue stream limits the size of any one property with respect to our total assets.
- We are not liable for abandonment and reclamation costs on our royalty lands.
- Due to our high percentage of royalty lands, we have one of the lowest all-in cost structures of our peer group. In addition, we maintain a focus on controlling direct costs to maximize profitability.
- We negotiate agreements that provide mechanisms to ensure that our interests are protected.
- Systems and processes are in place to identify any unpaid or incorrect revenues.
- We maintain a dedicated compliance function, with an aggressive auditing program, to ensure that the terms of the various agreements are followed. During 2015, our audit staff issued audit exception queries amounting to $3.8 million, bringing the total amount of audit exception queries since 1997 to $70.3 million, of which we have successfully recovered $55.9 million.
- We adhere to strict investment criteria for acquisitions, seeking quality royalty and working interest properties that have attractive returns, acceptable risk profiles and long economic lives.
- We market our products to a diverse range of buyers or with our diverse range of royalty payors. Currently, we do not have any commodity price, exchange rate, or interest rate hedging programs in place.
- We employ a qualified Manager that has many years of experience and knowledge in managing our assets.
- We maintain levels of liability insurance that meet or exceed industry standards.
- We employ a conservative approach to debt management. As circumstances warrant, we allocate a portion of funds from operations to debt repayment.

Environmental Regulation and Risk

The oil and gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on our operations and financial condition. For information about climate change and other environmental regulations, see “Industry Conditions” in our Annual Information Form.

Controls and Accounting Matters

In compliance with National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings* (NI 52-109), Freehold has filed certificates signed by our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) that, among other things, deal with the matter of disclosure controls and procedures and internal control over financial reporting. While we believe that our disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance, we do not expect that the controls will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

Disclosure Controls

As of December 31, 2015, an internal evaluation was carried out of the effectiveness of Freehold's disclosure controls and procedures. This evaluation was performed under the supervision of, and with the participation of the CEO and the CFO. It took into consideration Freehold's Disclosure, Insider Trading, Code of Business Conduct and Conflict of Interest, and Whistleblower policies, as well as the functioning of the Manager, the officers, the Board and Board Committees. In addition, the evaluation covered the processes, systems and capabilities relating to regulatory filings, public disclosures, and the identification and communication of material information. Based on this evaluation, management has concluded that Freehold's disclosure controls and procedures were effective as at December 31, 2015, in ensuring that material information is made known to management in a timely manner, particularly during the period in which the annual filings were being prepared, and information required to be disclosed by Freehold in its annual filings, interim filings or other reports filed or submitted by Freehold under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

Internal Control Over Financial Reporting

Our CEO and CFO are responsible for establishing and maintaining internal control over financial reporting (ICFR). They have caused ICFR to be designed under their supervision to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with Canadian GAAP. The control framework used to design ICFR is the Internal Control – Integrated Framework (2013 COSO Framework) published by The Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Under the supervision of the CEO and CFO, Freehold conducted an evaluation of the effectiveness of its ICFR as at December 31, 2015, as structured within the COSO Framework. Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2015, our ICFR provides reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. There were no changes in our ICFR during 2015 that materially affected Freehold's ICFR.

New Accounting Standards

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.

Critical Accounting Estimates

Our financial statements are prepared within a framework of Canadian GAAP (being IFRS) selected by management and approved by our Board. The assets, liabilities, revenues, and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and gas reserve estimation, depletion, impairment of assets, oil and gas revenue accruals, oil and gas royalty interests, decommissioning obligations, income taxes, and share based and other compensation. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

An estimate is considered a critical accounting estimate if it requires management to make assumptions about matters that are highly uncertain, and if different estimates that could have been used would have a material impact. We continually evaluate the estimates and assumptions. In the normal course, changes are made to assumptions underlying all critical accounting estimates to reflect current economic conditions, and updating of historical information is used to develop the assumptions. Except as discussed in this MD&A, we are not aware of trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

Reserve Estimates, Depletion and Impairment Testing

The current estimates of oil and gas reserves and our future capital expenditures are based on an independent evaluation conducted as of December 31, 2015. Reserve estimates are updated once a year (as at December 31) and when a significant acquisition or development is completed. At each interim reporting date, reserves are also adjusted for production. The reserve and recovery information provided are only estimates. The actual production and ultimate reserves may be greater than or less than the estimates and the differences may be material.

Petroleum and natural gas interests, including the cost of production equipment, future capital costs, estimated decommissioning costs and directly attributable general and administrative costs are depleted on the unit-of-production method based on estimated proved plus probable oil and gas reserves. Reserves are converted to equivalent units on the basis of relative energy content. An increase in estimated proved plus probable oil and gas reserves would result in a corresponding reduction in the depletion rate.

At each reporting date, Freehold assesses groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If any such indication of impairment exists, Freehold makes an estimate of its recoverable amount. Where the carrying amount of a group of assets exceeds its recoverable amount, the assets are considered impaired and written down. Impairments can be reversed if the impairment indicators have been reversed. Indicators and recoverable amounts are primarily estimates from independent sources. The determination of CGUs is subject to management judgment.

Oil and Gas Revenue Accruals and Royalty Interests

Freehold follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of revenues, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. We expect that these accrual estimates will be revised, upwards or downwards, based on the receipt of actual results. We have no operational control over our royalty lands, and we primarily hold small interests in several thousand wells. Thus, obtaining timely production data from the well operators is extremely difficult. As a result, we use government reporting databases and past production receipts to estimate revenue accruals.

Significant judgment is required to determine the interests of royalty properties in areas where mineral rights are shared with Canpar (see Related Party Transactions). We use publicly available information on geological formations to apportion revenues between the entities in accordance with the respective party's interests. As new geological information becomes available and as part of our ongoing internal audit activities, we periodically revise these allocations and consideration is transferred to reflect the changes

Decommissioning Liability

Freehold measures decommissioning liability as the present value of management's best estimate of the expenditure required to settle the obligation at the reporting date using a risk-free discount rate. This estimate is recognized when a legal or constructive obligation arises and is recorded as a long-term liability, with a corresponding increase in the carrying value of the petroleum and natural gas working interest asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. At each reporting date, the passage of time and changes to estimates results in liability changes and the amount of accretion is charged against current period income.

In determining our decommissioning liability, we are required to make a significant number of estimates with respect to activities that will occur in many years to come. In arriving at the recorded amount of the decommissioning liability, numerous assumptions are made with respect to ultimate settlement amounts, inflation factors, risk-free discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The decommissioning liability also results in an increase to the carrying cost of capital assets. The obligation accretes to a higher amount with the passage of time as it is determined using discounted present values. A change in any one of the assumptions could affect the estimated future obligation and in return, net income. It is difficult to determine the impact of a change in any one of our assumptions. As a result, a reasonable sensitivity analysis cannot be performed.

Income Taxes

We follow the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on deferred income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of income tax may be greater than or less than the estimates and the differences may be material.

Share Based and Other Compensation

Freehold funds its proportionate share of the costs associated with a long-term incentive compensation plan (LTIP) for employees of Rife Resources Ltd. (Rife) through the Manager of Freehold, Rife Resources Management Ltd. The LTIP uses a combination of the value of phantom Rife shares and Freehold shares as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Dividends to shareholders paid by Freehold during the vesting period are assumed to be reinvested in notional rights on the dividend payment date. Since participants in the LTIP receive a cash payment on a fixed vesting date, a liability is determined and recognized as services are rendered based on the fair value of the rights at each period end. The valuation incorporates the consideration of share price, the number of rights outstanding at each period end, an estimated performance multiplier, and an estimated forfeiture rate. Compensation expense is recognized over the vesting period. If factors change actual payments resulting from the LTIP can vary significantly from amounts expensed in prior periods.

Freehold funds its proportionate share of a retirement benefit for certain former employees of the Manager. Freehold accrues its share of the post retirement costs over the service life of the employees. Period expenses are estimates and actual amounts paid can vary.

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 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;
- 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, our exposure in emerging resource plays, and the potential impact of horizontal drilling on production and reserves;
- development of working interest properties;
- participation in the DRIP and our use of cash preserved through the DRIP;
- estimated capital budget and expenditures and the timing thereof;
- Freehold's decommissioning liability and timing of payment thereof;
- average production and contribution from royalty lands;
- key operating assumptions;
- amounts and rates of income taxes and timing of payment thereof;
- our tax pools and the expected tax horizon;
- our dividend policy;
- treatment under governmental regulatory regimes and tax laws; and
- our assessment of litigation risk.

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

- volatility in market prices for crude oil and natural gas;
- lack of pipeline capacity;
- currency fluctuations;
- changes in income tax laws or changes in tax laws, regulations, royalties, or incentive programs relating to the oil and gas industry;
- reliance on royalty payors to drill and produce on our lands and their ability to pay their obligations;
- uncertainties or imprecision associated with estimating oil and gas reserves;
- stock market volatility and our ability to access sufficient capital from internal and external sources;
- a significant or prolonged downturn in general economic conditions or industry activity;
- incorrect assessments of the value of acquisitions;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- geological, technical, drilling, and processing problems;
- environmental risks and liabilities inherent in oil and gas operations; and
- other factors discussed under Business Risks and Mitigating Strategies in this MD&A, and under Risk Factors and elsewhere in our Annual Information Form.

Readers are cautioned that the foregoing list of factors is not exhaustive.

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 participation rates in the DRIP and use of cash preserved through the DRIP;
- 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 Outlook section.

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, 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.

Additional GAAP Measures

This MD&A contains the term “funds from operations”, which does not have a standardized meaning prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities. Funds from operations, as presented, is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to net income or other measures of financial performance calculated in accordance with GAAP. 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.

Non-GAAP Financial Measures

Within this MD&A, references are made to terms commonly used as key performance indicators in the oil and natural 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 and natural gas production during the period, with natural gas converted to equivalent barrels of oil as described below.

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.

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.

CONSOLIDATED FINANCIAL STATEMENTS

Management's Report

The accompanying consolidated financial statements and other financial information in this Financial Report have been prepared by management, who is responsible for their integrity, consistency, objectivity and reliability. To fulfill this responsibility, Freehold maintains policies, procedures and systems of internal control to ensure that reporting practices and accounting and administrative procedures are appropriate to provide reasonable assurance that the assets are safeguarded, transactions are properly authorized and relevant and reliable financial information is produced.

These consolidated financial statements have been prepared in conformity with International Financial Reporting Standards and, where appropriate, reflect estimates based on management's judgment. The financial information presented throughout this Financial Report is generally consistent with the information contained in the accompanying consolidated financial statements.

Independent auditors, KPMG LLP, were appointed by the shareholders to perform an examination of the corporate and accounting records so as to express an opinion on the consolidated financial statements. Their examination included tests and procedures considered necessary to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with International Financial Reporting Standards.

The consolidated financial statements have been further reviewed and approved by the Board of Directors acting through its Audit Committee, which is comprised of independent directors. The Audit Committee, which meets with the auditors and management to review the activities of each and reports to the Board of Directors, oversees management's responsibilities for the financial reporting and internal control systems. The auditors have full and direct access to the Audit Committee and meet periodically with the committee both with and without management present to discuss their audit and related findings.

Thomas J. Mullane	Darren G. Gunderson
President and Chief Executive Officer	Vice-President, Finance and Chief Financial Officer

March 3, 2016

Independent Auditors' Report

To the Shareholders of Freehold Royalties Ltd.

We have audited the accompanying consolidated financial statements of Freehold Royalties Ltd., which comprise the consolidated balance sheets as at December 31, 2015 and 2014, the consolidated statements of income (loss) and comprehensive income (loss), cash flows and changes in shareholders' equity for the years ended December 31, 2015 and 2014, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Freehold Royalties Ltd. as at December 31, 2015 and 2014, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants

March 3, 2016
Calgary, Canada

Consolidated Balance Sheets

($000s)	December 31, 2015	December 31, 2014
Assets		
Current assets:		
Cash	$ 876	$ 1,126
Accounts receivable	21,046	26,430
Current taxes receivable	73	2,597
	21,995	30,153
Acquisition advance	-	949
Exploration and evaluation assets (note 4)	49,479	37,852
Petroleum and natural gas interests (note 5)	846,825	584,323
Deferred income tax asset (note 3, 11)	21,095	-
	$ 939,394	$ 653,277
Liabilities and Shareholders' Equity		
Current liabilities:		
Dividends payable	$ 6,924	$ 10,488
Accounts payable and accrued liabilities	9,826	15,864
Current portion of share based and other compensation payable (note 10)	194	611
	16,944	26,963
Decommissioning liability (note 7)	27,635	21,279
Share based and other compensation payable (note 10)	191	321
Long-term debt (note 6)	152,000	139,000
Deferred income tax liability (note 3, 11)	-	44,847
Shareholders' equity:		
Shareholders' capital (note 8)	1,050,494	635,223
Contributed surplus	3,282	2,577
Deficit	(311,152)	(216,933)
	742,624	420,867
	$ 939,394	$ 653,277

See accompanying notes to consolidated financial statements.

On behalf of the Board of Directors of Freehold Royalties Ltd.:

D. Nolan Blades
Director

Arthur N. Korpach
Director

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

($000s, except per share and weighted average data)	Year Ended December 31 2015	2014
Revenue:		
Royalty income and working interest sales	$ 135,664	$ 199,850
Royalty expense	(2,297)	(5,666)
	133,367	194,184
Gain on corporate acquisition (note 3)	24,340	-
Other income (note 9)	756	-
Expenses:		
Operating	18,215	18,992
General and administrative	10,643	8,679
Share based and other compensation (note 10)	766	438
Interest and financing	5,696	4,405
Depletion and depreciation (note 5)	95,703	67,145
Impairment (note 5)	38,800	-
Accretion of decommissioning liability (note 7)	566	498
Management fee (note 9)	3,693	4,743
	174,082	104,900
Income (loss) before taxes	(15,619)	89,284
Income taxes (note 11):		
Current expense (recovery)	(5,097)	22,178
Deferred expense (recovery)	(6,442)	659
	(11,539)	22,837
Net income (loss) and comprehensive income (loss)	$ (4,080)	$ 66,447
Net income (loss) per share, basic and diluted	$ (0.05)	$ 0.94
Weighted average number of shares:		
Basic	90,504,786	71,029,156
Diluted	90,504,786	71,170,896

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

	Year Ended December 31	
($000s)	2015	2014
Operating:		
Net income (loss)	$ (4,080)	$ 66,447
Items not involving cash:		
Depletion and depreciation	95,703	67,145
Impairment	38,800	-
Share based and other compensation	766	438
Deferred income tax expense (recovery)	(6,442)	659
Accretion of decommissioning liability	566	498
Management fee	3,693	4,743
Gain on corporate acquisition	(24,340)	-
Expenditures on share based and other compensation	(619)	(1,195)
Decommissioning expenditures	(227)	(288)
Funds from operations	103,820	138,447
Changes in non-cash working capital (note 14)	6,693	(4,060)
	110,513	134,387
Financing:		
Issuance of shares, net of issue costs	390,236	141,085
Long-term debt	13,000	90,000
Dividends paid	(76,478)	(86,521)
	326,758	144,564
Investing:		
Acquisition advance	949	(949)
Acquisitions	(411,352)	(248,274)
Capital expenditures	(22,295)	(33,701)
Changes in non-cash working capital (note 14)	(4,823)	4,941
	(437,521)	(277,983)
Increase (decrease) in cash	(250)	968
Cash, beginning of year	1,126	158
Cash, end of year	$ 876	$ 1,126

See accompanying notes to consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

($000s)	Year Ended December 31 2015	2014
Shareholders' capital:		
Balance, beginning of year	$ 635,223	$ 455,497
Shares issued for dividend reinvestment plan	17,225	32,264
Shares issued in lieu of management fee	3,693	4,743
Shares issued for deferred share unit plan redemption	-	180
Shares issued for equity offering	405,600	146,810
Issue costs, net of tax effect	(11,247)	(4,271)
Balance, end of year	1,050,494	635,223
Contributed surplus:		
Balance, beginning of year	2,577	2,167
Share based compensation expense	705	666
Deferred share unit plan redemption	-	(256)
Balance, end of year	3,282	2,577
Deficit:		
Balance, beginning of year	(216,933)	(163,592)
Net income (loss) and comprehensive income (loss)	(4,080)	66,447
Dividends declared	(90,139)	(119,788)
Balance, end of year	(311,152)	(216,933)
	$ 742,624	$ 420,867

See accompanying notes to consolidated financial statements.

Notes to the Consolidated Financial Statements

Years ended December 31, 2015 and 2014

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 consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and the interpretations of the International Financial Reporting Interpretations Committee (IFRIC) and adopted by the Canadian Institute of Chartered Accountants (CICA). The CICA recognizes IFRS as Canadian generally accepted accounting principles (GAAP) for publicly accountable enterprises.

These consolidated financial statements were approved by the Board of Directors on March 3, 2016.

b. Basis of measurement and principles of consolidation

These 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. Use of estimates and judgment

The preparation of financial statements in accordance with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses during the reporting period. Actual results could differ as a result of using estimates.

The amounts recorded for the depletion of petroleum and natural gas properties, the provision for decommissioning liability and the amounts used in the impairment calculations are based on estimates of petroleum and natural gas reserves and future costs to develop those reserves. By their nature, these estimates of reserves, costs and related future cash flows are subject to uncertainty, and the impact on the financial statements of future periods could be material.

The decommissioning liability amounts recorded are based on estimates of inflation rates, risk-free rates, timing of abandonments and future abandonment costs, all of which are subject to uncertainty. The long-term incentive plan amounts recorded include an estimate of forfeitures and certain management assumptions. The retirement benefit amounts recorded include an estimated discount rate. Actual results could differ as a result of using estimates.

Income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantively enacted income tax rates. The effect of a change in income tax rates on deferred income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of income tax may be greater than or less than the estimates and the differences may be material.

The determination of a cash generating unit (CGU) and whether an acquisition transaction constitutes a business combination is subject to management judgments. The recoverability of petroleum and natural gas interests and exploration and evaluation assets are assessed at the CGU level. A CGU is the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other CGUs. Each acquisition transaction is reviewed by management and judgment is used when determining if the transaction met the IFRS 3 inputs and processes criteria for business combinations.

Freehold follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of revenues, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. It is expected that these accrual estimates will be revised, upwards or downwards, based on the receipt of actual results. Freehold has no operational control over its royalty lands and primarily holds small interests in several thousand wells. Thus, obtaining timely production data from the well operators is extremely difficult. As a result, Freehold uses government reporting databases and past production receipts to estimate revenue accruals.

Significant judgment is required to determine the interests of royalty properties in areas where mineral rights are shared with a related party, Canpar Holdings Ltd. (Canpar). Freehold uses publicly available information on geological formations to apportion revenues between the entities in accordance with the respective party's interests. As new geological information becomes available and as part of its ongoing internal audit activities, Freehold periodically revises these allocations and consideration is transferred to reflect the changes.

d. Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the functional currency of Freehold and its subsidiaries.

2. Significant Accounting Policies

a. Jointly controlled operations and jointly controlled assets

Some of Freehold's oil and gas activities involve jointly controlled assets. These consolidated financial statements include only Freehold's share of the jointly controlled assets and a proportionate share of the relevant revenue and related costs.

b. Exploration and evaluation assets

Exploration and evaluation (E&E) costs are accounted for in accordance with IFRS 6, *Exploration for and Evaluation of Mineral Resources*. All E&E costs incurred after acquiring the "right to explore" are capitalized into a single cost pool. Upon determination of the technical feasibility and commercial viability of reserves, the associated E&E costs are assessed for impairment and the estimated recoverable amount is transferred to petroleum and natural gas interests. All costs incurred prior to acquiring the "right to explore" are expensed as incurred. At each reporting date, E&E costs are reviewed for indicators of impairment. If circumstances indicate the carrying amount exceeds its recoverable amount, the cost is written down to its recoverable amount and the difference is accounted for as an impairment expense. No depletion or depreciation is charged to E&E.

c. Petroleum and natural gas interests

Petroleum and natural gas interests

Petroleum and natural gas interests are classified under International Accounting Standard (IAS) 16 as Property, Plant and Equipment and include both working and royalty interests, stated at cost, less accumulated depletion and accumulated impairment losses. All costs incurred after determining technical feasibility and commercial viability of reserves are capitalized. Subsequent expenditures are capitalized only where they enhance the economic benefits of the asset. A gain or loss on disposal of a petroleum and natural gas interest is recognized to the extent that the net proceeds exceed or are less than the appropriate portion of the capitalized costs of the asset.

Depletion

Petroleum and natural gas interests, including the costs of production equipment, future capital costs, estimated decommissioning liability costs, and directly attributable general and administrative costs, are depleted on the unit-of-production method based on estimated proved plus probable oil and gas reserves. Reserves are converted to equivalent units on the basis of relative energy content.

Impairment

At each reporting date, Freehold assesses groups of assets or CGUs, for impairment whenever events or changes in circumstances indicate that the carrying value of the CGU may not be recoverable. If any such indication of impairment exists, Freehold makes an estimate of its recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs of disposal (FVLCTD) and its value in use (VIU). Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down. In assessing VIU, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money. FVLCTD is the amount obtainable from the sale of assets in an arm's length transaction less cost of disposal.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or have decreased. If such indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the CGU's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the CGU is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depletion, had no impairment loss been recognized for the CGU in prior periods. Such a reversal is recognized in profit or loss. After such a reversal, the depletion charge is adjusted in future periods to allocate the CGU's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

d. Decommissioning liability

Freehold measures the decommissioning liability as the present value of management's best estimate of the expenditure required to settle the liability at the reporting date using a risk-free discount rate. This estimate is recognized when a legal or constructive obligation arises and is recorded as a long-term liability, with a corresponding increase in the carrying value of the petroleum and natural gas working interest asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. At each reporting date, the passage of time and changes to estimates results in liability changes, and the amount of accretion is charged against current period income.

e. Income taxes

Freehold follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on deferred income tax liabilities and assets is recognized in income in the period that the change occurs.

f. Share based and other compensation plans

Long-term incentive plan

Freehold funds its proportionate share of the costs associated with a long-term incentive compensation plan (LTIP) for employees of Rife Resources Ltd. (Rife) through the Manager of Freehold, Rife Resources Management Ltd. The LTIP uses a combination of the value of phantom Rife shares and Freehold shares as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Dividends to shareholders paid by Freehold during the vesting period are assumed to be reinvested in notional rights on the dividend payment date. Since participants in the LTIP receive a cash payment on a fixed vesting date, a liability is determined and recognized as services are rendered based on the fair value of the rights at each period end. The valuation incorporates the consideration of the share price, the number of rights outstanding at each period end, an estimated performance multiplier (0.25 to 1.5 times the market value) and an estimated forfeiture rate. Compensation expense is recognized over the vesting period.

Deferred share unit plan

A deferred share unit (DSU) plan was established for the non-management directors of Freehold whereby fully-vested DSUs are granted annually. Under this plan, dividends to shareholders declared prior to redemption are assumed to be reinvested on behalf of the directors in notional share units on the dividend payment date. Compensation expense is recognized at the market value of Freehold's common shares at the time of grant or dividend, with a corresponding increase to contributed surplus. Upon redemption of the DSUs for Freehold's common shares, the amount previously recognized in contributed surplus is recorded as an increase to shareholders' capital.

Retirement benefit

Freehold funds its proportionate share of a retirement benefit for certain former employees of the Manager, upon fulfilling certain criteria. The retirement benefit is paid in four equal installments. Freehold accrues its share of the post retirement costs over the service life of the employees.

g. Net income per share

Basic net income per share is calculated using the weighted average number of shares outstanding for each period. Diluted net income per share is calculated using the weighted average number of diluted shares outstanding for each period. Diluted shares outstanding are calculated assuming that any proceeds received from options with a market value in excess of option price would be used to buy back shares at the average market price for the period.

h. Revenue recognition

Revenue is made up of royalty income, working interest sales and other income earned during the period. Royalty income and working interest sales represent the sale of crude oil, natural gas, natural gas liquids and other products. Revenue is recognized when title passes from Freehold, or the operator of Freehold's properties, to its customers. Royalty income and working interest sales are measured at the fair value, using estimates, per the terms of various royalty interest and working interest agreements. Actual results could differ as a result of using estimates and any differences are recorded in the period in which actuals are received.

i. Financial instruments

All financial instruments, including all derivatives, are recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities, except those measured at fair value through profit and loss and available-for-sale, are measured at amortized cost using the effective interest rate method. Available for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to earnings when derecognized or impaired.

Cash and short-term investments, if any, are financial assets measured at fair value through profit or loss, and the fair values approximate their carrying value due to their short-term nature. Accounts receivable and current taxes receivable are classified as loans and receivables and are measured at amortized cost. Dividends payable, accounts payable and accrued liabilities and long-term debt are classified as other financial liabilities and are measured at amortized cost. The fair values of accounts receivable, current taxes receivable, dividends payable, accounts payable and accrued liabilities approximate their carrying value due to the short-term nature of these instruments. Freehold has not designated any financial instruments as available-for-sale, held-to-maturity or financial liabilities at fair value through profit and loss. Freehold does not have any material embedded derivatives that required separate recognition and measurement.

A three level hierarchy that reflects the significance of the inputs used in making the fair value measurements is required. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement.

j. 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.

3. 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 (subject to certain post-closing adjustments) with Freehold funding the deal through its existing credit facilities. Pursuant to the plan of arrangement, Anderson shareholders exchanged their shares for shares of a newly formed publicly listed company, Anderson Energy Inc. (New Anderson). In addition, prior to Freehold acquiring the outstanding shares, Anderson transferred certain assets and liabilities to New Anderson. The liabilities transferred to New Anderson included Anderson's liabilities and obligations for its convertible debentures. One of the directors (chairman) of Anderson before amalgamation, and now new Anderson, is also a director of Freehold.

Immediately following the completion of the acquisition of Anderson, Freehold completed a corporate restructuring pursuant to which Freehold first amalgamated with Anderson (after Anderson had changed its name to 1851328 Alberta Ltd.) and subsequently amalgamated with its wholly-owned subsidiary, Freehold Resources Ltd. In addition, pursuant to the restructuring, Freehold Holdings Trust was established and became a partner in Freehold Royalties Partnership.

Acquisition costs of $0.3 million were expensed for the year ended December 31, 2015 (2014 - $0.4 million) relating to this transaction. This transaction added approximately $220 million to existing tax pools. Details of the transaction and the allocation of the purchase price are as follows:

($000s)	
Petroleum and natural gas interests	7,533
Deferred tax asset	55,383
Decommissioning liability	(3,576)
Debt assumed	(18,500)
Gain on corporate acquisition	(24,340)
	16,500
Debt repaid	18,500
Total consideration paid	35,000

On closing of the acquisition, Anderson had bank debt of approximately $18.5 million which was immediately and concurrently repaid (as a condition of closing). 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.

For the year ended December 31, 2015, as a result of this transaction, $1.8 million was included in revenue and net income was reduced by $1.7 million. The pro forma estimated effects on revenue and net income of the transaction as if it closed January 1, 2015 were minimal.

4. Exploration and Evaluation Assets

($000s)	December 31 2015	December 31 2014
Balance, beginning of year	37,852	24,858
Acquisitions (note 5)	14,300	15,342
Transfers to petroleum and natural gas interests (note 5)	(2,673)	(2,348)
Balance, end of year	49,479	37,852

There were no impairments for the years ended December 31, 2015 or December 31, 2014.

5. Petroleum and Natural Gas Interests

($000s)	December 31 2015	December 31 2014
Cost		
Balance, beginning of year	874,377	600,171
Acquisitions	369,585	232,932
Capital expenditures	22,295	33,701
Capitalized portion of long term incentive plan	11	(63)
Transfers from exploration and evaluation assets (note 4)	2,673	2,348
Decommissioning liability additions and revisions (note 7)	2,441	5,288
Balance, end of year	1,271,382	874,377
Accumulated depletion and depreciation		
Balance, beginning of year	(290,054)	(222,909)
Impairment	(38,800)	-
Depletion and depreciation	(95,703)	(67,145)
Balance, end of year	(424,557)	(290,054)
Net book value, end of year	846,825	584,323

The depletion calculation included $14.5 million (2014 - $18.7 million) for estimated future development costs associated with proved plus probable undeveloped reserves.

For the year ended December 31, 2015, Freehold capitalized $1.5 million (2014 - $1.3 million) of administrative costs and capitalized $11,000 (2014 – recovered $63,000) of LTIP costs directly related to development activities.

Including the corporate acquisition described in note 3, during the year ended December 31, 2015, Freehold had several acquisition expenditures of $411.4 million (2014 - $248.3 million), including adjustments.

Impairment

At December 31, 2015 Freehold tested its two working interest cash generating units (CGUs) for impairment due to the continued drop in expected future commodity prices as recognized by industry reserve evaluators. Freehold estimated the recoverable amount as the value in use based on discounted future net cash flows of proved and probable reserves using forecast prices and costs, discounted at 10% (pre-tax). In determining the discount rate, Freehold considered an estimated industry weighted cost of capital and the resource composition of the assets. The estimate was based on

Freehold's December 31, 2015 reserve report. Management recognizes that all assumptions and estimates affecting the value are subject to a high degree of uncertainty.

Freehold recognized a non-cash impairment charge on its Southeast Saskatchewan Working Interest CGU of $8.0 million as the carrying value exceeded the estimated value in use. The Southeast Saskatchewan Working Interest CGU contains all of Freehold's working interest properties in southeast Saskatchewan. The estimated recoverable amount of the Southeast Saskatchewan CGU at December 31, 2015 is $29.1 million. In addition, Freehold recognized a non-cash impairment charge on its Other Working Interest CGU of $30.8 million as the carrying value exceeded the estimated value in use. The Other Working Interest CGU contains Freehold's diverse group of working interest properties outside of the Southeast Saskatchewan Working Interest CGU. The estimated recoverable amount of the Other Working Interest CGU at December 31, 2015 is $54.7 million.

As future commodity prices continue to fluctuate, additional impairment charges or recoveries could be recorded in future periods. The value in use estimates are categorized as Level 3 according to the IFRS 13 fair value hierarchy. The following table summarizes key benchmarks used in the impairment estimate.

	WTI	WCS	AECO	Exchange rate
	US$/bbl	Cdn$/bbl	Cdn$/Mcf	Cdn$/US$
2016	45.00	45.26	2.25	0.75
2017	60.00	57.96	2.95	0.80
2018	70.00	65.88	3.42	0.83
2019	80.00	75.11	3.91	0.85
2020	81.20	77.03	4.20	0.85
2021	82.42	78.19	4.28	0.85
Average annual increase, thereafter	1.5%	1.5%	1.5%	-

There were no impairments for the year ended December 31, 2014.

6. Long-Term Debt

Freehold has a $245 million extendible revolving term credit facility with a syndicate of four Canadian chartered banks, on which $152 million was drawn at December 31, 2015. 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. The facilities are extendible annually with the latest review completed in May 2015. Freehold's borrowing base is dependent on the lenders annual review and interpretation of Freehold's reserves and future commodity prices, with the next renewal to occur by May 2016. 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 December 31, 2015 and December 31, 2014 the fair values of the long-term debt approximated its carrying value, as the long-term debt carries interest at prevailing market rates.

In 2015, the average effective interest rate on advances under Freehold's credit facilities was 2.9% (2014 - 3.3%).

7. Decommissioning Liability

Freehold has no decommissioning liability on its royalty interest properties. Freehold's decommissioning liability results from its responsibility to abandon and reclaim its net share of all working interest properties. The undiscounted value of Freehold's total decommissioning liability is estimated to be $40.3 million (2014 - $33.4 million). Payments to settle the obligations are expected to occur over the next 55 years, with the majority being settled within 10 to 20 years. At December 31, 2015, a risk-free rate of 2.2% (2014 – 2.3%) and an inflation rate of 1.5% (2014 - 1.5%) were used to calculate the fair value.

($000s)	December 31 2015	December 31 2014
Balance, beginning of year	21,279	15,781
Liabilities incurred	1,091	1,010
Liabilities settled	(227)	(288)
Revision in estimates [(1)]	1,350	4,278
Accretion expense	566	498
Corporate acquisition (note 3)	3,576	-
Balance, end of year	27,635	21,279

(1) Revision in estimates is primarily a result of changes in the risk-free rate, and is also affected by changes in abandonment costs and assumptions.

8. Shareholders' Capital

Freehold has authorized an unlimited number of common shares, without stated par value. Freehold has authorized 10,000,000 preferred shares, without stated par value, of which none have been issued.

Shares Issued and Outstanding

	December 31, 2015		December 31, 2014	
	Shares	Amount ($000s)	Shares	Amount ($000s)
Balance, beginning of year	74,918,711	635,223	67,746,470	455,497
Issued for dividend reinvestment plan	1,218,129	17,225	1,498,250	32,264
Issued in lieu of management fee	269,978	3,693	206,280	4,743
Issued for deferred share unit plan redemption	-	-	10,090	180
Issued for equity offering	22,533,334	405,600	5,457,621	146,810
Issue cost, net of tax effect	-	(11,247)	-	(4,271)
Balance, end of year	98,940,152	1,050,494	74,918,711	635,223

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 (see note 9) issuing 1,833,334 common shares, both at a price of $18.00 per share for gross proceeds of $405.6 million. The issue costs including underwriters' fees were $15.4 million ($11.2 million net of tax effect).

On July 16, 2014, Freehold closed a bought deal equity offering, issuing 4,900,000 common shares and a private equity offering with CN Pension Trust Funds (see note 9) issuing 557,621 common shares, both at a price of $26.90 per share for gross proceeds of $146.8 million. The issue costs including underwriters' fees were $5.7 million ($4.3 million net of tax effect).

At December 31, 2015, a balance of 2,475,367 shares was reserved for the dividend reinvestment plan (DRIP), 966,115 shares for the management fee (note 9) and 270,935 shares for the deferred share unit plan (note 10).

For the year ended December 31, 2015, Deferred Share Units were excluded from the calculation of diluted net loss per share as their effect was anti-dilutive.

9. 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.

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. This agreement was recently amended on November 9, 2015. The new amended and restated management agreement caps the management fee at 71,912 shares per quarter for 2016 and requires a reduction of shares in future years. For the year ended December 31, 2015, Freehold issued 269,978 shares (2014 – 206,280) as a management fee to the Manager pursuant to the management agreement. The ascribed value of $3.7 million (2014 – $4.7 million) was based on the closing price of the shares on the last trading day of each quarter.

For the year ended December 31, 2015, the Manager charged $9.0 million in general and administrative costs (2014 – $7.5 million). At December 31, 2015, there was $0.7 million (2014 – $0.5 million) in accounts payable and accrued liabilities relating to these costs.

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 December 31, 2015, there was $nil (2014 - $0.3 million) in accounts payable and accrued liabilities relating to these transactions. In addition, Freehold receives royalties from Rife pursuant to various royalty agreements. For the year ended December 31, 2015, Freehold received royalties of approximately $1.5 million (2014 – $2.2 million). At December 31, 2015, there was $0.1 million (2014 - $0.2 million) in accounts receivable relating to these transactions. On November 27, 2014, Freehold acquired royalty interests in Soda Lake Saskatchewan and Lindbergh Alberta for $10.1 million from Rife, including adjustments.

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. 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.

Freehold and Canpar have evaluated certain of these royalty interests where, among other factors, the identification of the reservoir formation was not straight forward and therefore ultimate ownership of the royalty interest wells was uncertain between Freehold and Canpar. An ongoing project relating to these interests was completed during the year whereby a settlement was reached and Freehold recognized $0.8 million of other income.

At December 31, 2015, there was $nil (2014 – $nil) in accounts receivable and accounts payable and accrued liabilities relating to transactions with Canpar.

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. In addition, concurrent with the closing of the bought deal equity offering on July 16, 2014, CN Pension Trust Funds invested approximately $15 million in Freehold through the purchase of 557,621 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.

Expenses relating to compensation for key management personnel, considered to be Freehold's Board of Directors and Senior Management, are as follows:

($000s)	December 31 2015	December 31 2014
Short-term benefits (including employee wages and directors fees)	1,346	1,208
Share based compensation (note 10a and 10b)	723	580
Total	2,069	1,788

10. Share Based and Other Compensation

a. Long-term incentive plan

Freehold funds its proportionate share of the costs associated with the LTIP for employees of Rife through the Manager, as described in note 2f. The share based compensation expense was based on the consideration of the share price, the number of rights outstanding at each period end, an estimated performance multiplier and an estimated forfeiture rate. The 2012 LTIP grants valued at $0.5 million were paid out in 2015. The total expensed for the year ended December 31, 2015 was $0.1 million (2014 – recovery $0.3 million). For the year ended December 31, 2015, Freehold capitalized $11,000 (2014 – recovered $63,000) of LTIP costs directly related to development activities.

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

($000s)	December 31 2015	December 31 2014
Balance, beginning of year	741	2,098
Increase (decrease) in liability	61	(355)
Cash payout	(545)	(1,002)
Balance, end of year	257	741
Current portion of liability	120	545
Long-term portion of liability	137	196

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

Phantom Common Shares

	December 31 2015	December 31 2014
Balance, beginning of year [1]	126,073	119,138
Issued	57,019	38,145
Dividends reinvested [1]	11,294	9,263
Cash payout	(44,070)	(40,473)
Balance, end of year	150,316	126,073

(1) Balance as at December 31, 2014 has been adjusted for revised estimates.

b. Deferred share unit plan

Freehold has a DSU plan for non-management directors as described in note 2f. As at December 31, 2015, there were 177,012 DSUs outstanding (2014 – 136,455), which are redeemable for an equal number of shares any time after the director's retirement. For the year ended December 31, 2015 no DSUs were redeemed. For the year-end December 31, 2014, 14,414 DSUs were redeemed, resulting in the issuance of 10,090 shares from treasury. In payment of withholding tax, 4,324 were cancelled and the cash value of $0.1 million was remitted to Canada Revenue Agency.

Deferred Share units

	December 31 2015	December 31 2014
Balance, beginning of year	136,455	121,317
Annual grants	28,007	19,280
Additional resulting from dividends	12,550	10,272
Redeemed	-	(14,414)
Balance, end of year	177,012	136,455

For the year ended December 31, 2015, Freehold expensed $0.7 million (2014 - $0.7 million) of share based compensation with a corresponding increase to contributed surplus.

c. Retirement benefit

Freehold participates in its proportionate share of a retirement benefit plan for certain former employees of the Manager as described in note 2f. For the year ended December 31, 2015, Freehold expensed $11,000 (2014 - $49,000).

($000s)	December 31 2015	December 31 2014
Accrued benefit obligation, beginning of year	191	244
Current service cost	11	49
Payments	(74)	(102)
Accrued benefit obligation, end of year	128	191
Current portion of liability	74	66
Long-term portion of liability	54	125

11. Income Taxes

Freehold uses the asset and liability method of accounting for income taxes, as described in note 2e.

The provision for taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial effective tax rate to Freehold's income before taxes. This difference is reconciled as follows:

($000s, except as noted)	December 31 2015	December 31 2014
Income (loss) before taxes	(15,619)	89,284
Combined federal and provincial tax rate	26.2%	25.4%
Computed expected income tax expense (recovery)	(4,092)	22,678
Increase (decrease) in income tax resulting from:		
Gain on corporate acquisition	(6,377)	-
Effect of rate change	(958)	-
Miscellaneous items	(112)	159
Total income taxes	(11,539)	22,837

The components of deferred income taxes are as follows:

($000s)	December 31 2015	December 31 2014
Deferred income tax assets:		
Non-capital losses	44,645	-
Decommissioning liability	7,461	5,405
Share issue expense	4,415	1,481
Deferred income tax liabilities:		
Petroleum and natural gas interests	(30,213)	(40,698)
Deferred tax on partnership income	(6,203)	(11,927)
Other	990	892
Net deferred income tax asset (liability)	21,095	(44,847)

The continuity of deferred income taxes is as follows:

($000s)	Balance December 31 2014	Recognized in Profit or Loss	Recognized in Equity	Recognized in Corporate Acquisition	Balance December 31 2015
Non-capital losses	-	(11,743)	-	56,388	44,645
Decommissioning liability	5,405	1,148	-	908	7,461
Share issue expense	1,481	(1,183)	4,117	-	4,415
Petroleum and natural gas interests	(40,698)	12,398	-	(1,913)	(30,213)
Deferred tax on partnership income	(11,927)	5,724	-	-	(6,203)
Other	892	98	-	-	990
Total	(44,847)	6,442	4,117	55,383	21,095

Freehold's deferred tax liability primarily relates to the deferral on partnership income and its assets having a higher carrying value relative to the associated tax value. Freehold's deferred tax asset primarily relates to the non-capital losses due to a corporate acquisition (note 3). When combined there is an overall net deferred tax asset.

12. Capital Management

Freehold is a publicly traded dividend-paying corporation incorporated under the laws of the Province of Alberta. Its primary focus is acquiring and managing oil and gas royalties and developing and producing its working interest oil and gas assets. Freehold receives revenue from oil and gas properties as reserves are produced, which is paid to shareholders on a regular basis over the economic life of the properties. Freehold's objective for managing capital is to maximize long-term shareholder value by distributing to shareholders any cash that is not required for financing operations or capital investment growth opportunities that may offer shareholders better value.

Freehold defines capital as long-term debt, shareholders' equity and working capital based on the consolidated financial statements. Freehold's capital structure is managed by taking into account operating activities, debt levels, debt covenants, capital expenditures, DRIP participation, dividend levels and taxes, among others. In addition, changes in economic conditions, commodity prices and the risk characteristics of Freehold's assets are considered. Freehold has a declining asset base, therefore ongoing development activities and acquisitions are necessary to replace production and add additional reserves. From time to time, Freehold may issue shares or adjust capital spending to manage current and projected debt levels.

Freehold retains working capital primarily to fund capital expenditures or acquisitions, pay dividends and reduce bank indebtedness. Freehold has chosen to issue its DRIP out of treasury, which increases its flexibility with the use of working capital. DRIP participation levels can fluctuate significantly on a monthly basis depending on shareholder requirements.

Management of Freehold's capital structure is facilitated through its financial and operating forecasting processes. The forecast of Freehold's future cash flows is based on estimates of production, commodity prices, forecast capital, royalty expenses, operating expenditures, taxes and other investing and financing activities. The forecast is regularly updated based on new commodity prices and other changes that Freehold views as critical in the current environment. Selected forecast information is frequently provided to and approved by the Board of Directors.

Freehold is bound by non-financial covenants on its credit facilities. The covenants are monitored as part of management's internal review to ensure compliance with requirements. Under the credit facilities, Freehold is restricted from paying dividends if it is or would be in default under the credit facilities or if borrowings thereunder exceed the borrowing base. As at December 31, 2015, Freehold was in compliance with all such covenants (see note 6).

Capitalization

($000s, except as noted)	December 31 2015	December 31 2014
Shareholders' equity	742,624	420,867
Long term debt	152,000	139,000
Working capital	(5,051)	(3,190)
Net debt [1]	146,949	135,810
Cash provided by operating activities for last 12 months	110,513	134,387
Change in non-cash operating working capital	(6,693)	4,060
Trailing 12 months funds from operations	103,820	138,447
Net debt to trailing 12 month funds from operations (times)	1.4	1.0

(1) Net debt as presented is a non-GAAP financial measures and does not have any standardized meaning prescribed by IFRS; and therefore may not be comparable to a similar measure of other entities.

13. Financial Instrument Risk Management

Freehold has exposure to credit, liquidity and market risks from its use of financial instruments. Management employs the following strategies to mitigate these risks.

a. Credit risk

Credit risk is the risk of financial loss to Freehold if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from Freehold's receivables. A large part of accounts receivable is with oil and gas industry operators, either as joint venture partners or as payors of various royalty agreements. These agreements provide mechanisms to ensure that Freehold's interests are protected. There are also systems and processes in place to identify any unpaid or incorrect revenues. Freehold's diversified revenue stream limits the size of any one property or industry operator with respect to total receivables.

Freehold maintains a dedicated compliance function, with an aggressive auditing program, to ensure that the terms of the various agreements are followed, including that royalties are paid correctly on production from Freehold's lands in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken. Freehold also audits its working interest properties to ensure that capital costs, operating expenses and production volumes are properly allocated.

The carrying amounts of accounts receivable and cash represent Freehold's maximum credit exposure. Freehold did not have an allowance for doubtful accounts as at December 31, 2015 or 2014, and did not provide for any doubtful accounts and was not required to write off any receivables during the years ended December 31, 2015 or 2014. Freehold considers all material amounts greater than three months to be past due. Due to the nature of Freehold's royalty income assets, there are amounts over three months which require significant time and effort to collect. Estimates of amounts owed for various time periods are as follows:

($000s)	Less than 3 months	4-12 months	over 1 year	Total
Accounts receivable	18,062	1,989	995	21,046

Freehold markets approximately 75% of its production along with the operator or royalty payor under the terms of a diverse number of agreements. Freehold takes its production in kind (currently approximately 25%) and sells to two primary purchasers.

b. Liquidity risk

Liquidity risk is the risk that Freehold will not be able to meet financial obligations as they come due. Management maintains a conservative approach to debt management that aims to provide maximum financial flexibility with respect to acquisitions and development expenditures, while maintaining stable dividend payments. At December 31, 2015, there was $108 million of available capacity under the credit facilities. As circumstances warrant, management allocates a portion of funds from operations to debt repayment. Management prepares annual capital expenditure and operating budgets, which are regularly monitored and updated. In addition, dividend levels are monitored and adjusted as necessary to levels that are supported by our funds from operations.

Freehold's non-derivative financial liabilities include its dividends payable, accounts payable and accrued liabilities, share based and other compensation payable and long-term debt. Freehold has no derivative financial liabilities. The following table outlines cash flows associated with the contractual maturities of Freeholds non-derivative financial liabilities as at December 31, 2015:

($000s)	Less than 1 Year	2-3 Years	Total
Dividends payable	6,924	-	6,924
Accounts payable and accrued liabilities	9,826	-	9,826
Share based and other compensation payable	194	191	385
Long-term debt	-	152,000	152,000
Total	16,944	152,191	169,135

c. Market risk

Market risk is the risk that changes in market prices, such as foreign currency exchange rates, commodity prices and interest rates, will affect net income or the value of financial instruments. The Board reviews the potential use of derivative contracts on a quarterly basis. For short-term investments, if any, Freehold selects counterparties based on strong credit ratings and monitors all investments to ensure a stable return.

Foreign currency exchange rate risk

Freehold does not sell or transact in any foreign currency; however, the underlying market prices in Canada for oil and natural gas are influenced by changes in the exchange rate between the Canadian and U.S. dollar. During the years ended December 31, 2015 and 2014, Freehold had no foreign exchange related derivative contracts in place. Assuming all other variables held constant, a $0.01 change (plus or minus) in the U.S./Canadian dollar exchange rate for the year ended December 31, 2015, would have resulted in a corresponding change to income before taxes of approximately $1.4 million (2014 - $1.8 million).

Commodity price risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate with changes in commodity prices. Commodity prices for oil and natural gas are influenced by the relationship between the Canadian and U.S. dollar as well as macroeconomic events that dictate the levels of supply and demand. During the years ended December 31, 2015 and 2014, Freehold had no commodity price related derivative contracts in place. Assuming all other variables held constant, a US$1.00 change (plus or minus) in the WTI crude oil price for the year ended December 31, 2015, would have resulted in a corresponding change to income before taxes of approximately $2.2 million (2014 - $1.7 million). A $0.25 change (plus or minus) in the AECO natural gas price would have resulted in a corresponding change to income before taxes of approximately $1.9 million (2014 - $1.7 million).

Interest rate risk

Freehold is exposed to interest rate risk on outstanding bank debt, which has a floating interest rate, and fluctuations in interest rates would impact future cash flows. Assuming all other variables held constant, a 1% change (plus or minus) in the interest rate for the year ended December 31, 2015 would have resulted in a corresponding change to income before taxes of approximately $1.7 million (2014 - $1.2 million).

14. Supplemental Disclosure

a. Statements of income and comprehensive income presentation

Freehold's consolidated statements of income and comprehensive income are prepared by nature of expense.

b. Supplemental cash flow disclosure

Changes in Non-Cash Working Capital Balance

($000s)	December 31 2015	December 31 2014
Accounts receivable	5,384	(843)
Current taxes receivable	2,524	(2,597)
Accounts payable and accrued liabilities	(6,038)	5,051
Current taxes payable	-	(730)
	1,870	881
Operating	6,693	(4,060)
Investing	(4,823)	4,941
	1,870	881

Cash Expenses Paid (RECEIVED)

($000s)	December 31 2015	December 31 2014
Interest	5,757	4,629
Taxes paid (received)	(7,621)	25,505

15. 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, believes it has no merit and intends to aggressively defend itself in the claim. The claim's outcome is not determinable and therefore no liability has been recorded in the financial statements.

Supplemental Information

The majority of our assets are royalty interests and under National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* (NI 51-101) royalty interests cannot be included under gross reserves. This causes our gross reserves to be lower than our net reserves and makes it difficult for investors to compare our reserves and finding and development costs to exploration and development companies. We believe the most appropriate measure of reserves and finding and development costs for Freehold is on a net basis.

As at year-end 2015, our undeveloped land was independently valued at $111.7 million by Seaton-Jordan & Associates Ltd. Our total land holdings encompass approximately 3.7 million gross acres, over 90% of which are royalties. Of this, our mineral title lands (including royalty assumption lands), which we own in perpetuity, cover more than 750,000 acres; all but approximately 300,000 gross acres of which are currently leased. In addition, we have gross overriding royalty interests in over 2.5 million acres.

These royalty interest lands are significant to Freehold. The majority of these lands are leased to third party operators. As a royalty owner, we have no operational control over the operator's future development activities. As such, the extent of drilling and development activity in future years can be difficult to predict. However, these operators have historically invested significant amounts to generate future reserve additions, and production from which Freehold receives certain royalties. Reserve values do not include potential reserve additions that may occur as a result of future drilling on most of our royalty lands. In addition, based on an internal estimate, we have estimated the net present value of the future royalty revenue from our potash reserves at $13.5 million before tax (discounted at 10%).

Our oil and gas reserves were independently evaluated by Trimble Engineering Associates Ltd. (Trimble) as at December 31, 2015. The evaluation was conducted in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Our Reserves Committee met with Trimble to review the findings and procedures, and the reserves report has been accepted by our Board of Directors.

This supplemental information contains a number of oil and gas metrics, including finding and development costs, finding, development and acquisition costs, recycle ratio and reserves life index, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies. Such metrics have been included herein to provide readers with additional measures to evaluate Freehold's performance; however, such measures are not reliable indicators of the future performance of Freehold and future performance may not compare to the performance in previous periods.

Our Annual Information Form, including reserves disclosure required under National Instrument NI 51-101, is available at www.sedar.com and on our website at www.freeholdroyalties.com.

SUMMARY OF OIL AND GAS RESERVES
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS (1)

	Light and Medium Crude Oil(2)		Heavy Crude Oil		Total Crude Oil	
Reserves Category	Gross (4) (Mbbls)	Net(5) (Mbbls)	Gross (4) (Mbbls)	Net(5) (Mbbls)	Gross (4) (Mbbls)	Net(5) (Mbbls)
Proved						
Developed producing	1,470	5,640	651	3,981	2,121	9,621
Developed non-producing	90	78	-	3	90	81
Undeveloped	20	1,917	-	242	20	2,159
Total proved	1,580	7,635	651	4,227	2,231	11,861
Probable	1,519	4,711	722	2,443	2,241	7,154
Total proved plus probable	3,099	12,346	1,373	6,670	4,472	19,016

	Conventional Natural Gas(3)		Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Gross (4) (MMcf)	Net(5) (MMcf)	Gross (4) (Mbbls)	Net(5) (Mbbls)	Gross (4) (Mboe)	Net(5) (Mboe)
Proved						
Developed producing	6,441	36,997	148	888	3,342	16,675
Developed non-producing	1,645	1,349	59	42	424	348
Undeveloped	-	19,958	-	427	20	5,913
Total proved	8,087	58,303	207	1,357	3,786	22,936
Probable	5,817	31,296	157	748	3,368	13,118
Total proved plus probable	13,903	89,599	364	2,105	7,154	36,054

(1) Numbers may not add due to rounding.
(2) Includes an immaterial amount of tight oil reserves.
(3) Includes an immaterial amount of shale gas and coal bed methane reserves.
(4) Gross reserves are our share of working interest properties before deduction of royalties payable to others. Gross reserves exclude royalty interests.
(5) Net reserves are our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands.

The summary reserves and finding and development cost data below is presented on a net basis (our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands).

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2015 FORECAST PRICES AND COSTS ($000s) (1) (2)

	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
Proved					
Developed producing	767,278	564,204	446,998	371,727	319,597
Developed non-producing	4,276	3,089	2,354	1,863	1,515
Undeveloped	302,280	216,824	162,572	126,054	100,381
Total proved	1,073,834	784,116	611,925	499,644	421,493
Probable	730,355	390,233	248,229	175,678	133,226
Total proved plus probable	1,804,189	1,174,349	860,154	675,322	554,719

	After Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
Proved					
Developed producing	767,278	564,204	446,998	371,727	319,597
Developed non-producing	4,276	3,089	2,354	1,863	1,515
Undeveloped	262,811	192,394	146,898	115,687	93,343
Total proved	1,034,366	759,686	596,251	489,277	414,455
Probable	542,795	290,023	186,727	134,569	104,166
Total proved plus probable	1,577,161	1,049,709	782,978	623,847	518,621

(1) Based on the December 31, 2015 escalated oil and gas price forecasts by an independent qualified reserves evaluator. Future net revenue values do not represent fair market value. Reserve values do not include potential reserve additions that may occur as a result of future drilling on our royalty lands. Columns may not add due to rounding.

(2) The after-tax net present value calculation reflects the tax burden on the properties on a standalone basis, utilizing our tax pools to the maximum depreciation rate as currently permitted. It does not consider the corporate-level tax situation, or tax planning. It does not provide an estimate of the value at the corporate level, which may be significantly different. See our financial statements and accompanying MD&A for additional tax information.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2015
FORECAST PRICES AND COSTS ($000s) (1)

	Reserves Category	
	Proved	Proved Plus Probable
Royalty Income	1,019,441	1,675,142
Revenue from working interest properties	208,429	433,902
Royalty expense on working interest properties	(26,009)	(64,298)
Operating costs	(109,083)	(207,946)
Development costs	(3,216)	(13,875)
Well abandonment and reclamation costs(3)	(15,728)	(18,736)
Future net revenue before income taxes	1,073,834	1,804,189
Future income taxes(2)	(39,468)	(227,027)
Future net revenue after income taxes	1,034,366	1,577,161

(1) Future net revenue calculation includes future capital expenditures required to bring booked non-producing and undeveloped reserves on production. Future net revenue values do not represent fair market value. Reserve values do not include potential reserve additions that may occur as a result of future drilling on our royalty lands. Columns may not add due to rounding.

(2) The after-tax net present value calculation reflects the tax burden on the properties on a standalone basis, utilizing our tax pools to the maximum depreciation rate as currently permitted. It does not consider the corporate-level tax situation, or tax planning. It does not provide an estimate of the value at the corporate level, which may be significantly different. See our financial statements and accompanying MD&A for additional tax information.

(3) Reflects estimated abandonment and reclamation for all wells (both existing and undrilled wells) that have been attributed reserves. Does not reflect abandonment and reclamation costs for wells with no attributed reserves or for facilities or pipelines.

RESERVE LIFE INDEX
AS OF DECEMBER 31, 2015 (1)

	Proved Producing	Total Proved	**Proved Plus Probable**
Net Reserves (Mboe)	16,675	22,936	**36,054**
Net Production (Mboe)	3,198	3,276	**3,649**
Reserves Life Index (years)	5.2	7.0	**9.9**

(1) Reflects the theoretical production life of a property if the remaining reserves were produced out at current rates. The index is calculated by dividing the reserves in the selected reserve category at a certain date by the estimated production for the first year production period (calculated by dividing the Trimble forecast of 2016 net production into the remaining net reserves).

RECONCILIATION OF NET RESERVES (1)
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS (1)

	Light and Medium Crude Oil(2)			Heavy Crude Oil		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2014	4,014	3,106	7,120	4,010	2,592	6,602
Extensions	399	237	636	267	134	401
Improved recovery	-	-	-	-	-	-
Technical revisions	312	(642)	(330)	317	(349)	(32)
Discoveries	-	-	-	-	-	-
Acquisitions	4,167	2,036	6,202	498	58	556
Dispositions	(38)	(19)	(56)	-	-	-
Economic factors	3	(6)	(3)	(2)	8	6
Production (2)	(1,222)	-	(1,222)	(864)	-	(864)
December 31, 2015	**7,635**	**4,711**	**12,346**	**4,227**	**2,443**	**6,670**

	Conventional Natural Gas(3)			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2014	60,369	22,525	82,894	1,536	639	2,175
Extensions	800	856	1,656	22	11	33
Improved recovery	-	-	-	-	-	-
Technical revisions	(1,541)	3,193	1,652	(155)	(25)	(180)
Discoveries	-	-	-	-	-	-
Acquisitions	9,177	5,738	14,915	238	182	421
Dispositions	(387)	(1,266)	(1,653)	(21)	(70)	(92)
Economic factors	(97)	249	152	(4)	10	7
Production (2)	(10,018)	-	(10,018)	(259)	-	(259)
December 31, 2015	**58,303**	**31,296**	**89,599**	**1,357**	**748**	**2,105**

	Total Oil Equivalent		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2014	19,622	10,091	29,713
Extensions	820	525	1,346
Improved recovery	-	-	-
Technical revisions	218	(485)	(267)
Discoveries	-	-	-
Acquisitions	6,432	3,232	9,664
Dispositions	(123)	(300)	(423)
Economic factors	(20)	54	35
Production (2)	(4,014)	-	(4,014)
December 31, 2015	**22,936**	**13,118**	**36,054**

(1) Net reserves are defined as our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands. Numbers may not add due to rounding.

(2) Light and medium crude oil includes an immaterial amount of tight oil reserves.

(3) Conventional natural gas includes an immaterial amount of shale gas and coal bed methane reserves.

FINDING, DEVELOPMENT AND ACQUISITION (FD&A) COSTS (1)

Net Proved Reserves	2015	2014	2013	Three-year results
Finding and development expenditures ($000s)	**22,295**	33,701	29,287	**85,283**
Change in future development capital estimates ($000s)	**(1,005)**	1,638	1,142	**1,776**
Net reserve additions by development (Mboe)	**820**	956	834	**2,610**
Finding and development cost ($/boe)	**25.95**	36.98	36.47	**33.35**
Acquisition expenditures ($000s)	**366,009**	233,274	10,091	**609,374**
Net reserve additions by acquisition (Mboe)	**6,432**	5,903	142	**12,477**
Acquisition cost ($/Boe)	**56.90**	39.52	71.21	**48.84**
Total expenditures ($000s)	**388,304**	266,975	39,378	**694,657**
Change in future development capital estimates ($000s)	**(1,005)**	1,638	1,142	**1,776**
Net reserve additions (Mboe)	**7,253**	6,858	976	**15,087**
Finding, development and acquisition cost ($/boe)	**53.40**	39.17	41.52	**46.16**

Net Proved Plus Probable Reserves	2015	2014	2013	Three-year results
Finding and development expenditures ($000s)	**22,295**	33,701	29,287	**85,283**
Change in future development capital estimates ($000s)	**(4,834)**	2,702	3,448	**1,315**
Net reserve additions by development (Mboe)	**1,346**	1,665	1,649	**4,660**
Finding and development cost ($/boe)	**12.98**	21.87	19.85	**18.59**
Acquisition expenditures ($000s)	**366,009**	233,274	10,091	**609,374**
Net reserve additions by acquisition (Mboe)	**9,664**	7,765	294	**17,723**
Acquisition cost ($/Boe)	**37.87**	30.04	34.38	**34.38**
Total expenditures ($000s)	**388,304**	266,975	39,378	**694,657**
Change in future development capital estimates ($000s)	**(4,834)**	2,702	3,448	**1,315**
Net reserve additions (Mboe)	**11,010**	9,430	1,943	**22,383**
Finding, development and acquisition cost ($/boe)	**34.83**	28.60	22.04	**31.09**

(1) Finding, development and acquisition costs are used as a measure of capital efficiency. The calculation for finding and development costs includes all exploration and development capital for that period plus the change in future development capital for that period. This total capital including the change in the future development capital is then divided by the reserves addition for that period (excluding all revisions for that same period). The calculation for finding, development and acquisition costs is calculated in the same manner except it also accounts for any acquisition costs (except as otherwise noted) incurred during the period. Excluded from 2015 acquisition expenditures are $45.3 million for undeveloped land acquired and other costs unrelated to reserve additions. Included in 2014 acquisition costs are $15.2 million of exploration costs from four wells drilled on the East Edson joint venture lands and included in 2014 finding and development costs are $0.1 million of miscellaneous exploration costs. Excluded from 2014 acquisition costs are $15.0 million of costs for undeveloped land acquired during the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

RECYCLE STATISTICS, NET PROVED PLUS PROBABLE RESERVES

	2015	2014	2013	Three-year results
Operating netback ($/boe)(1)(4)	**28.83**	52.30	47.90	42.10
Finding, development and acquisition costs ($/boe)(2)(4)	**34.83**	28.60	22.04	31.09
Recycle Ratio (times)(3)	**0.8**	1.8	2.1	1.3

(1) Total revenue, less operating costs and royalty expenses.

(2) Development expenditures, plus change in future capital, plus acquisition costs; divided by net reserves added through development and acquisition activities.

(3) Operating netback divided by the average cost of acquiring and developing new reserves.

(4) Operating netback is based on gross production, while development and acquisition costs are based on net reserves.

LAND HOLDINGS
AS OF DECEMBER 31, 2015

	Developed	Undeveloped	Total
Mineral Title Lands	386,145	276,338	662,483
Royalty Assumption Lands	73,218	19,839	93,057
Total Title Lands	**459,363**	**296,177**	**755,540**
Gross Overriding Royalty	1,791,522	591,768	2,383,290
Total Royalty Lands	**2,250,885**	**887,945**	**3,138,830**
Working Interest Properties	205,803	49,961	255,764
Total	**2,456,688**	**937,906**	3,394,594
Additional Lands(1)			280,000
Total Land Holdings			**3,674,594**

(1) Approximately 280,000 gross acres of additional title and royalty lands acquired from Penn West Petroleum Ltd. in 2015, which has not been categorized as of yet.

LAND HOLDINGS BY PROVINCE

	Royalty Interest		Working Interest				Total	
	Developed	*Undeveloped*	*Developed*		*Undeveloped*		*Developed*	*Undeveloped*
	Gross	*Gross*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Gross*
Alberta	1,688,012	567,188	162,912	35,169	33,590	7,287	1,850,924	600,778
Saskatchewan	368,837	261,636	23,365	8,394	10,034	5,322	392,202	271,670
Ontario	86,913	21,732	0	0	0	0	86,913	21,732
British Columbia	98,085	26,231	19,247	1,265	6,131	101	117,332	32,362
Manitoba	9,038	11,158	279	13	206	9	9,317	11,364
TOTAL(1)	**2,250,885**	**887,945**	**205,803**	**44,841**	**49,961**	**12,719**	**2,456,688**	**937,906**

(1) Approximately 280,000 gross acres of lands acquired from Penn West Petroleum Ltd. in 2015 have not been included in these totals as they have not been released from our integration process and therefore have not been broken down by province as of yet.

TEN-YEAR REVIEW

	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
Financial ($millions, except as noted)[1]										
Gross revenue	**135.7**	199.9	181.6	168.1	157.9	138.2	120.0	204.1	152.2	143.1
Net income (loss)[1]	**(4.1)**	66.4	57.9	46.3	55.3	49.3	31.7	110.0	(1.2)	45.2
Per share ($)[2]	**(0.05)**	0.94	0.86	0.71	0.92	0.85	0.63	2.23	(0.02)	0.92
Funds from operations[3]	**103.8**	138.4	119.4	103.9	128.2	107.0	95.1	171.3	121.0	119.9
Per share ($)[2][3]	**1.15**	1.95	1.79	1.60	2.14	1.83	1.90	3.47	2.46	2.44
Dividends declared	**90.1**	119.8	112.5	109.6	101.0	98.1	70.5	143.7	94.5	103.1
Per share ($)[2][4]	**1.00**	1.68	1.68	1.68	1.68	1.68	1.40	2.91	1.92	2.10
Acquisitions	**411.4**	248.3	10.1	60.9	7.5	38.6	9.5	7.7	90.5	5.4
Capital expenditures	**22.3**	33.7	29.3	36.7	25.6	18.1	15.5	13.0	12.2	11.4
Long-term debt	**152.0**	139.0	49.0	18.0	48.0	65.0	45.0	140.0	178.0	100.0
Operating										
Production (boe/d)	**10,945**	9,180	8,913	8,850	7,476	7,615	7,302	7,804	8,484	8,412
Royalty Interest (%)	**76**	74	70	71	75	73	70	71	69	78
Oil and NGL (%)	**62**	63	64	64	63	62	64	63	63	62
Land (gross acres, millions)	**3.7**	3.2	3.1	3.0	2.7	2.8	2.4	2.4	2.4	2.1
Net reserves (Mmboe)[5]	**36.1**	29.7	23.1	24.4	22.2	23.6	24.1	25.4	28.0	28.0
Reserve life index (years)	**9.9**	9.0	8.5	8.5	9.1	9.5	9.7	9.8	9.5	9.6
Share Data										
High ($)	**20.62**	28.15	24.88	22.45	23.28	21.14	17.00	24.40	15.85	23.06
Low ($)	**8.73**	17.02	21.00	17.25	14.51	15.08	6.87	9.15	12.51	12.43
Close ($)	**10.86**	19.12	22.11	22.40	19.41	20.49	15.09	10.49	15.60	14.81
Volume (millions)	**75.3**	43.6	25.8	28.6	28.1	25.8	30.0	36.5	25.1	35.5
Outstanding (millions)										
At period end	**98.9**	74.9	67.7	66.3	61.1	59.20	57.5	49.5	49.3	49.2
Weighted average	**90.5**	71.0	66.9	64.9	60.0	58.3	50.0	49.4	49.2	49.1

(1) Freehold's IFRS transition date was January 1, 2010 and reflects adjustments due to IFRS. Comparative information for 2006-2009 has not been restated.
(2) Prior to conversion to a corporation on December 31, 2010, Freehold had trust units outstanding instead of shares.
(3) See Additional GAAP measures and Non-GAAP Financial Measures.
(4) Based on the number of shares issued and outstanding at each record date.
(5) Net proved plus probable reserves.

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Corporate Director

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

Thomas J. Mullane
President & Chief Executive Officer
Rife Resources Ltd.

Marvin F. Romanow (1)
Corporate Director

David J. Sandmeyer (3)
Corporate Director

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

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

Officers

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Chair of the Board

Thomas J. Mullane
President & Chief Executive Officer

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

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Stock Exchange and Trading Symbol

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