CALGARY, ALBERTA--(Marketwired - Mar 3, 2016) - Freehold Royalties Ltd. (Freehold) (TSX:FRU) today announced 2015 fourth quarter results and reserves as at December 31, 2015.

Results at a Glance

	Three Months Ended December 31			Twelve Months Ended December 31		
FINANCIAL ($000s, except as noted)	2015	2014	Change	2015	2014	Change
Gross revenue	33,833	43,631	-22 %	135,664	199,850	-32 %
Net income (loss)	(7,423)	11,082	-167 %	(4,080)	66,447	-106 %
Per share, basic and diluted ($)	(0.08)	0.15	-153 %	(0.05)	0.94	-105 %
Funds from operations(1)	25,509	30,774	-17 %	103,820	138,447	-25 %
Per share, basic ($)(1)	0.26	0.41	-37 %	1.15	1.95	-41 %
Operating income(1)	29,186	37,584	-22 %	115,152	175,192	-34 %
Operating income from royalties (%)	89	80	11 %	87	78	12 %
Acquisitions	(143)	60,566	-100 %	411,352	248,274	66 %
Capital expenditures	5,607	13,500	-58 %	22,295	33,701	-34 %
Dividends declared	20,747	31,353	-34 %	90,139	119,788	-25 %
Per share ($)(2)	0.21	0.42	-50 %	1.00	1.68	-40 %
Net debt obligations(1)	146,949	135,810	8 %	146,949	135,810	8 %
Shares outstanding, period end (000s)	98,940	74,919	32 %	98,940	74,919	32 %
Average shares outstanding (000s)(3)	98,731	74,545	32 %	90,505	71,029	27 %
OPERATING						
Average daily production (boe/d)(4)	11,815	9,836	20 %	10,945	9,180	19 %
Average price realizations ($/boe)(4)	30.34	47.46	-36 %	33.20	58.91	-44 %
Operating netback ($/boe)(1) (4)	26.85	41.54	-35 %	28.83	52.30	-45 %

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

Dividend Announcement

Reflecting continued weakness in commodity prices, Freehold's Board of Directors has approved an adjustment to its monthly dividend to $0.04 per share from $0.07 per share. The Board of Directors has declared a dividend of Cdn. $0.04 per common share to be paid on April 15, 2016 to shareholders of record on March 31, 2016. Including the April 15 payment, our 12-month trailing cash dividends total $0.91 per share. This dividend is designated as an eligible dividend for Canadian income tax purposes.

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.

2015 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).

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 average 15% participation rate in Freehold's dividend reinvestment plan, which is subject to change at the participants discretion.

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.

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.

Fourth Quarter Production

Production volumes in Q4-2015 averaged 11,815 boe/d, an increase of 20% when compared with levels averaged in the comparative period in 2014.

- Royalty production averaged 9,249 boe/d in Q4-2015, a 26% increase when compared to Q4-2014. Oil and natural gas liquids production was up 46%, largely associated with acquisitions and the strength of our audit function. On the natural gas side, volumes were up 4% from Q4-2014.
- Working interest production volumes averaged 2,566 boe/d in Q4-2015, a 2% increase versus Q4-2014.

	Three Months Ended December 31				Twelve Months Ended December 31			
	2015	2014	Change		2015	2014	Change	
Royalty interest [1]								
Oil (bbls/d)	5,204	3,501	49	%	4,456	3,384	32	%
NGL (bbls/d)	498	403	24	%	422	435	-3	%
Natural gas (Mcf/d)	21,280	20,494	4	%	20,590	17,915	15	%
Oil equivalent (boe/d)	9,249	7,320	26	%	8,310	6,805	22	%
Working interest [1]								
Oil (bbls/d)	1,668	1,972	-15	%	1,720	1,851	-7	%
NGL (bbls/d)	185	101	83	%	159	102	56	%
Natural gas (Mcf/d)	4,276	2,657	61	%	4,533	2,531	79	%
Oil equivalent (boe/d)	2,566	2,516	2	%	2,635	2,375	11	%
Total								
Oil (bbls/d)	6,872	5,473	26	%	6,176	5,235	18	%
NGL (bbls/d)	683	504	36	%	581	537	8	%
Natural gas (Mcf/d)	25,556	23,151	10	%	25,123	20,446	23	%
Oil equivalent (boe/d)	11,815	9,836	20	%	10,945	9,180	19	%
Number of days in period (days)	92	92	0	%	365	365	0	%
Total volumes during period (Mboe)	1,087	905	20	%	3,995	3,350	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.

Royalty Interest Activity

In total, 377 (18.9 equivalent net) wells were drilled on our royalty lands through 2015 which was a 25% improvement versus 2014 on an equivalent net basis. Through Q4-2015, 85 gross (3.6 net) locations were drilled on our royalty lands; this compares to 138 gross (4.3 net) in Q4-2014.

Our royalty lands give us exposure to some of the most economic resource plays currently being pursued in the Western Canadian Sedimentary Basin. Through 2015, we have seen an increase in activity on our lands largely as a result of acquisitions made over the last two years. Some of the royalty drilling highlights are described below.

In the Viking Dodsland play horizontal drilling was very strong within the established royalty area. In 2015, the operator rig released 109 wells and has 64 gross wells licenced, representing a significant ready to drill inventory. The operator is currently focused on completing 21 wells from the Q4-2015 drill program.

In southeast Saskatchewan/Manitoba we have seen continued interest in our royalty lands situated in the heart of the Bakken and Mississippian subcrop play areas. In Q4-2015, seven gross Bakken horizontal wells were drilled on our royalty lands. In the Mississippian play areas, 10 gross horizontals wells were drilled for Midale and Frobisher targets. Operators achieved exceptional production results from these wells with 30-day average rates from each well exceeding 150 boe/d. Royalty drilling activity continued in Manitoba where several operators have drilled six gross wells targeting Reston and Bakken/Three Forks reservoirs.

In Central Alberta, three Nisku horizontals were drilled on our royalty lands located on the prolific Leduc Woodbend reef complex. The operator in this area is targeting the light oil trapped in Nisku reefs draped over the Leduc reef complex. Horizontal drilling and staged fracture treatments are leading to impressive 3-month average production rates of 160 boe/d per well. With modern drilling and completion technology there is abundant incremental light oil remaining to be recovered from these heritage Devonian reef production areas.

In the Deep Basin, we had five deep horizontal wells drilled on our royalty lands. Montney and Wilrich targets are being pursued by several operators in the overpressured liquids rich areas of the basin. Two of these horizontal tests targeting the Wilrich had first month average production exceeding 14 MMcf/d of gas plus associated liquids, which demonstrates the material nature of these play types.

	Three Months Ended December 31				Twelve Months Ended December 31			
	2015		2014		2015 [1]		2014	
		Equivalent		Equivalent		Equivalent		Equivalent

	Gross	Net(2)	Gross	Net (2)	Gross	Net(2)	Gross	Net (2)
Non-unitized wells	65	3.5	73	4.0	259	18.2	258	14.0
Unitized wells (3)	20	0.1	65	0.3	118	0.7	185	1.1
Total	85	3.6	138	4.3	377	18.9	443	15.1
Royalty joint venture (4)	-		9		4		13	

(1) 2015 counts for the twelve months ended December 31 include wells drilled on all 2015 acquisition lands from January 1, 2015.

(2) Equivalent net wells are the aggregate of the numbers obtained by multiplying each gross well by our royalty interest percentage.

(3) Unitized wells are in production units wherein we generally have small royalty interests in hundreds of wells.

(4) Wells drilled on various royalty joint venture lands, where equivalent net wells cannot be calculated.

Working Interest Activity

Freehold's working interest drilling program was relatively limited for Q4-2015. Five wells were drilled in our southeast Saskatchewan operating area for Midale and Bakken horizontal targets. Production results are very encouraging with current average production greater than 150 boe/d per well.

In addition, a number of Freehold operated wells drilled in the third quarter were brought on stream in Q4-2015. Two Mississippian Frobisher horizontals (100% interest) were placed on production in December with each well averaging 45 boe/d. Also our vertical heavy oil well drilled in the Greenstreet area (90% interest) was placed on production in November and is currently averaging approximately 40 boe/d.

Freehold is also encouraged by the strong production performance from its Pembina Cardium horizontal well drilled early in 2015 (42.5% working interest, 15% royalty interest). The well continues to produce strongly averaging greater than 250 boe/d for the quarter. Additional downspace locations offsetting this location are ready to be drilled when prices recover.

	Three Months Ended December 31				Twelve Months Ended December 31			
	2015		2014		2015		2014	
	Gross	Net(1)	Gross	Net (1)	Gross	Net(1)	Gross	Net (1)
Oil	5	0.7	22	4.9	39	7.3	47	11.3
Natural gas	-	-	3	0.8	4	0.2	7	0.9
Other	-	-	-	-	-	-	-	-
Total	5	0.7	25	5.7	43	7.5	54	12.2

(1) Excludes royalty interest portion on properties where Freehold has both a working interest and a royalty interest. The royalty interest portion is included in equivalent net wells in the Royalty Interest Wells Drilled table above.

2015 Year-end Reserves and Land Highlights

Freehold's reserves data is presented on a net basis (our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands), as under National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Act* ivities (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 to exploration and development companies. We believe the most appropriate measure of reserves for Freehold is net reserves. Reserve values do not include potential reserve additions that may occur as a result of future drilling on most of our royalty lands.

- Net present value of future net reserves before tax totalled $860 million (NPV 10), up from $786 million in 2014. The increase versus 2014 was associated with acquisitions completed through 2015, offset by the reduction in prices.
- Net proved plus probable reserves at December 31, 2015 totalled 36.1 MMboe, with reserves assigned to 26,948 wells. Net proved plus probable royalty interest reserves increased 26% year-over-year, and net proved plus probable working interest reserves were flat. Approximately 64% of our net reserves are in the proved category, and 73% of our net proved reserves are producing. On a boe basis, net reserves are 58% liquids (18% heavy oil, 34% light and medium oil, 6% natural gas liquids) and 42% natural gas.
- On our royalty lands, net proved plus probable reserve additions totalled 9.5 MMboe (81% liquids). Drilling added 0.9 MMboe of net proved plus probable reserves, and acquisitions added 8.6 MMboe of net proved plus probable reserves. Based on this, we replaced approximately 303% of 2015 production.
- Freehold's finding costs are calculated based on net reserves. In 2015, finding and development costs for net proved plus probable reserves were $12.98 per boe (including changes in future development capital), while acquisition costs were $37.87 per boe and the all-in finding, development and acquisition (FD&A) cost was $34.83 per boe (including changes in future development capital). Based on an operating netback of $28.83 per boe in 2015, these activities resulted in a recycle ratio of 0.8, and a three-year average recycle ratio of 1.4.
- Our land holdings as at December 31, 2015 encompassed approximately 3.7 million gross acres, up 16% from last year mainly as a result of acquisitions completed throughout the year. Royalty interests comprised over 90% of our acreage.
- As at year-end 2015, our undeveloped land was independently valued at $111.7 million by Seaton-Jordan & Associates Ltd.

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.

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 defined as 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 (000's)[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 (000's)(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.

Future Development Costs (Undiscounted) ($000s)(1)

	Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves
Year	(undiscounted)	(undiscounted)
2016	188	4,882
2017	1,477	4,233
2018	564	928
2019	73	2,117
2020	839	1,353
Remainder	76	362
Total	3,217	13,875

(1) The source of funding for future development costs includes internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue will not be materially affected by the costs of funding the future development expenditures. Columns may not add due to rounding.

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's 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

	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	(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	(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	(4,014)	-	(4,014)
December 31, 2015	22,936	13,118	36,054

(1) Net reserves are 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 change in reserves for that period excluding 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	2.2	1.4

(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.

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 participants discretion.
(4) Reported production for a period may include minor adjustments from previous production periods.
(5) Excludes share based and other compensation.

Condensed Consolidated Balance Sheets

($000s) (unaudited)	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
Acquistion advance	-	949
Exploration and evaluation assets	49,479	37,852
Petroleum and natural gas interests	846,825	584,323
Deferred income tax asset	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	194	611
	16,944	26,963
Decommissioning liability	27,635	21,279
Share based and other compensation payable	191	321
Long-term debt	152,000	139,000
Deferred income tax liability	-	44,847
Shareholders' equity:		
Shareholders' capital	1,050,494	635,223
Contributed surplus	3,282	2,577
Deficit	(311,152)	(216,933)
	742,624	420,867
	$ 939,394	$ 653,277

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

(unaudited)	Three Months Ended December 31		Twelve Months Ended December 31	
($000s, except per share and weighted average data)	2015	2014	2015	2014
Revenue:				
Royalty income and working interest sales	$ 33,833	$ 43,631	$ 135,664	$ 199,850
Royalty expense	(105)	(1,034)	(2,297)	(5,666)
	33,728	42,597	133,367	194,184
Gain on corporate acquisition	-	-	24,340	-
Other income	-	-	756	-
Expenses:				

Operating	4,542	5,013	18,215	18,992
General and administrative	2,420	2,102	10,643	8,679
Share based and other compensation	70	(1,164)	766	438
Interest and financing	1,221	1,196	5,696	4,405
Depletion and depreciation	26,397	19,237	95,703	67,145
Impairment	8,000	-	38,800	-
Accretion of decommissioning liability	152	123	566	498
Management fee	781	1,034	3,693	4,743
	43,583	27,541	174,082	104,900
Income (loss) before taxes	(9,855)	15,056	(15,619)	89,284
Income taxes:				
Current expense (recovery)	-	3,273	(5,097)	22,178
Deferred expense (recovery)	(2,432)	701	(6,442)	659
	(2,432)	3,974	(11,539)	22,837
Net income (loss) and comprehensive income (loss)	$ (7,423)	$ 11,082	$ (4,080)	$ 66,447
Net income (loss) per share, basic and diluted	$ (0.08)	$ 0.15	$ (0.05)	$ 0.94
Weighted average number of shares:				
Basic	98,730,518	74,544,796	90,504,786	71,029,156
Diluted	98,730,518	74,681,308	90,504,786	71,170,896

Condensed Consolidated Statements of Cash Flows

	Three Months Ended December 31		Twelve Months Ended December 31	
($000s) (unaudited)	2015	2014	2015	2014
Operating:				
Net income (loss)	$ (7,423)	$ 11,082	$ (4,080)	$ 66,447
Items not involving cash:				
Depletion and depreciation	26,397	19,237	95,703	67,145
Impairment	8,000	-	38,800	-
Share based and other compensation	70	(1,164)	766	438
Deferred income tax expense (recovery)	(2,432)	701	(6,442)	659
Accretion of decommissioning liability	152	123	566	498
Management fee	781	1,034	3,693	4,743
Gain on corporate acquisition	-	-	(24,340)	-
Expenditures on share based and other compensation	-	(91)	(619)	(1,195)
Decommissioning expenditures	(36)	(148)	(227)	(288)
Funds from operations	25,509	30,774	103,820	138,447
Changes in non-cash working capital	2,063	3,741	6,693	(4,060)
	27,572	34,515	110,513	134,387
Financing:				
Issuance of shares, net of issue costs	-	-	390,236	141,085
Long-term debt	(3,000)	6,000	13,000	90,000
Dividends paid	(17,965)	(20,350)	(76,478)	(86,521)
	(20,965)	(14,350)	326,758	144,564
Investing:				
Acquisition advance	-	49,211	949	(949)
Acquisitions	143	(60,566)	(411,352)	(248,274)
Capital expenditures	(5,607)	(13,500)	(22,295)	(33,701)
Changes in non-cash working capital	(530)	5,014	(4,823)	4,941
	(5,994)	(19,841)	(437,521)	(277,983)
Increase (decrease) in cash	613	324	(250)	968
Cash, beginning of period	263	802	1,126	158
Cash, end of period	$ 876	$ 1,126	$ 876	$ 1,126

Condensed Consolidated Statements of Changes in Shareholders' Equity

Twelve Months Ended

	December 31	
($000s) (unaudited)	2015	2014
Shareholders' capital:		
Balance, beginning of period	$ 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
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 period	1,050,494	635,223
Contributed surplus:		
Balance, beginning of period	2,577	2,167
Share based compensation expense	705	666
Deferred share unit plan redemption	-	(256)
Balance, end of period	3,282	2,577
Deficit:		
Balance, beginning of period	(216,933)	(163,592)
Net income (loss) and comprehensive income (loss)	(4,080)	66,447
Dividends declared	(90,139)	(119,788)
Balance, end of period	(311,152)	(216,933)
Total shareholders' equity	$ 742,624	$ 420,867

Forward-Looking Statements

This news release offers our assessment of Freehold's future plans and operations as at March 3, 2016, and contains forward-looking statements that we believe allow readers to better understand our business and prospects. These forward-looking statements include our expectations for 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;
- foreign exchange rates;
- drilling activity during 2016 and the impact on our production base;
- 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;
- average production and contribution from royalty lands;
- key operating assumptions;
- amounts and rates of income taxes and timing of payment thereof;
- maintaining our revised monthly dividend rate through 2016 and our dividend policy.

In addition, statements relating to "reserves" and the future net revenue associated with such reserves are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and can be profitably produced in the future.

Such statements are generally identified by the use of words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "plan", "intend", "believe", and similar expressions (including the negatives thereof). By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, continued weakness in the oil and gas industry, reliance on third party royalty payors and operators of our working interest properties, volatility of commodity prices, lack of pipeline capacity; currency fluctuations, imprecision of reserve estimates, royalties, environmental risks, taxation, regulation, changes in tax or other legislation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, and our ability to access sufficient capital from internal and external sources. Risks are described in more detail in our AIF.

With respect to forward-looking statements contained in this news release, we have made assumptions regarding, among other things, future commodity 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 producing our assets, our ability and the ability of our lessees to obtain equipment in a timely manner to carry out development activities, our ability to market our oil and gas successfully to current and new customers, our expectation for the consumption of crude oil and natural gas, our expectation for industry drilling levels, our ability to obtain financing on acceptable terms, and our ability to add production and reserves through development and acquisition activities. The key operating assumptions with respect to the forward-looking statements referred to above are detailed in the body of this news release.

You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. The forward-looking information contained in this document is expressly qualified by this cautionary statement. To the extent any guidance or forward looking statements herein constitute a financial outlook, they are included herein to provide readers with an understanding of management's plans and assumptions for budgeting purposes and readers are cautioned that the information may not be appropriate for other purposes. 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.

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.

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 bbl). 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 and observing trends, 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.

Additional GAAP Measures

This news release 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 news release, 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. 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 as a proportion of funds from operations for the previous twelve months. 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 above.

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

Oil and Gas Metrics

This news release 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.

Availability on SEDAR

Freehold's 2015 audited financial statements and accompanying Management's Discussion and Analysis (MD&A) are being filed today with Canadian securities regulators and will be available at www.sedar.com and on our website at www.freeholdroyalties.com. Our Annual Information Form (including reserves disclosure required under National Instrument NI 51-101) is expected to be filed by on or about March 7, 2016.

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