MANAGEMENT'S DISCUSSION AND ANALYSIS

The following management's discussion and analysis ("MD&A") of financial condition and results of operations for Whitecap Resources Inc. (the "Company" or "Whitecap") is dated November 1, 2016 and should be read in conjunction with the Company's unaudited interim consolidated financial statements and related notes for the period ended September 30, 2016, as well as the audited annual consolidated financial statements and related notes for the year ended December 31, 2015. These unaudited consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), specifically International Accounting Standard ("IAS") 34, *Interim Financial Reporting*, in Canadian dollars, except where indicated otherwise. Accounting policies adopted by the Company are set out in the notes to the audited annual consolidated financial statements for the year ended December 31, 2015. Additional information respecting Whitecap is available on SEDAR at www.sedar.com and on our website at www.wcap.ca.

The interim consolidated financial statements of Whitecap have been prepared by management and approved by the Company's Board of Directors.

DESCRIPTION OF BUSINESS

Whitecap is an oil-weighted growth company that pays a monthly cash dividend to its shareholders. Whitecap is focused on profitable per share growth on the Company's existing assets enhanced by opportunistic and accretive oil-based acquisitions. Whitecap's common shares are traded on the Toronto Stock Exchange under the symbol WCP.

2016 THIRD QUARTER FINANCIAL AND OPERATIONAL RESULTS

Production

Whitecap's average production volumes and commodity splits were as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Crude oil (bbls/d)	36,094	28,653	30,828	27,575
NGLs (bbls/d)	2,991	3,204	3,142	2,921
Natural gas (Mcf/d)	60,994	59,781	61,616	60,485
Total (boe/d)	49,251	41,821	44,239	40,577
Production split (%)				
Crude oil and NGLs	79	76	77	75
Natural gas	21	24	23	25
Total	100	100	100	100

Average production volumes increased 18 percent to 49,251 boe/d in the third quarter of 2016 from 41,821 boe/d in the third quarter of 2015. Year to date, average production volumes increased nine percent to 44,239 boe/d from 40,577 boe/d for the same period in 2015. The increases are primarily attributed to the acquisition of high quality, low decline oil-weighted assets in southwest Saskatchewan (the "Southwest Saskatchewan Acquisition") that closed on June 23, 2016 and the Company's successful execution of its development capital program partially offset by natural declines.

Our crude oil and NGL weighting in the third quarter of 2016 has increased three percent compared to the same period in 2015. The increase is primarily attributed to the oil-weighted properties acquired through the Southwest Saskatchewan Acquisition and our drilling program.

Petroleum and Natural Gas Sales

A breakdown of petroleum and natural gas sales is as follows:

	Three months ended September 30,		Nine months ended September 30,	
($000s)	2016	2015	2016	2015
Crude oil	159,852	136,987	380,398	416,611
NGLs	4,808	3,395	13,022	12,125
Natural gas	13,838	14,856	32,737	45,319
Petroleum and natural gas sales	178,498	155,238	426,157	474,055

Petroleum and natural gas sales in the third quarter of 2016 increased 15 percent to $178.5 million from $155.2 million in the third quarter of 2015. The increase of $23.3 million consists of $35.7 million attributed to higher production volumes partially offset by $12.4 million attributed to lower realized prices. Year to date petroleum and natural gas sales decreased 10 percent to $426.2 million from $474.1 million in the same period in 2015. The decrease of $47.9 million consists of $99.0 million attributed to lower realized prices partially offset by $51.1 million attributed to higher production volumes.

Benchmark and Realized Prices

Average benchmark and realized prices are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Benchmark prices				
WTI (US$/bbl) (1)	44.94	46.43	41.33	51.00
Exchange rate (USD/CAD)	1.31	1.31	1.32	1.26
WTI (C$/bbl)	58.65	60.79	54.47	64.13
Edmonton Par (C$/bbl)	54.68	56.17	50.01	58.53
Western Canadian Select (C$/bbl)	41.02	43.41	36.34	47.49
AECO natural gas ($/Mcf) (2)	2.32	2.90	1.85	2.77
Average realized prices (3)				
Crude oil ($/bbl)	48.14	51.97	45.03	55.34
NGLs ($/bbl)	17.47	11.52	15.13	15.21
Natural gas ($/Mcf)	2.47	2.70	1.94	2.74
Combined ($/boe)	39.39	40.35	35.16	42.79

Notes:

(1) WTI represents posting prices of West Texas Intermediate oil.

(2) Represents the AECO daily posting.

(3) Prior to the impact of hedging activities.

Whitecap's weighted average realized price prior to the impact of hedging activities decreased two percent to $39.39 per boe in the third quarter of 2016 compared to $40.35 per boe in the third quarter of 2015. Year to date, Whitecap's weighted average realized price prior to the impact of hedging activities decreased 18 percent to $35.16 per boe compared to $42.79 per boe in same period in 2015.

US$ WTI prices decreased three percent to US$44.94 per barrel in the third quarter of 2016 from US$46.43 per barrel in the third quarter of 2015. North American crude oil storage and production levels declined slightly in the third quarter of 2016, offset by relatively flat global demand and increased oil supply from certain OPEC member countries.

The Edmonton light sweet crude price differential to WTI decreased 13 percent to US$2.96 per barrel in the third quarter of 2016 from US$3.42 per barrel in the third quarter of 2015 as Canadian light oil production showed signs of decline in the low price environment and refinery demand was robust. Crude oil prices realized by Whitecap in southwest Saskatchewan are based on Fosterton oil prices, which received a premium to Western Canadian Select ("WCS") of US$1.73 per barrel in the third quarter of 2016. The WCS oil price differential to WTI increased by two percent to US$13.51 in the third quarter of 2016 from US$13.27

in the third quarter of 2015 as supply recovered after northern Alberta wild fires. Fosterton oil prices continue to receive a premium to WCS of approximately US$1.50-$1.70 per barrel.

The AECO daily spot price decreased 20 percent to $2.32 per Mcf in the third quarter of 2016 from $2.90 per Mcf in the third quarter of 2015. While gas storage levels were high at the beginning of the summer injection season, warm weather and increased cooling demand through mid to late summer supported prices and kept storage levels from increasing too rapidly.

Risk Management and Hedging Activities

Whitecap maintains an ongoing risk management program to reduce the volatility of revenues in order to fund capital expenditures and provide a measure of stability to Whitecap dividends. The Company has the approval of the Board of Directors to hedge a forward position of up to three years and up to 75 percent of its most recent quarter's average daily production, net of royalties.

The Company realized gains of $14.8 million and $66.8 million on its commodity risk management contracts in the three and nine months ended September 30, 2016 respectively. The unrealized losses are a result of the non-cash change in the mark-to-market values period over period. The significant assumptions made in determining the fair value of financial instruments are disclosed in Note 4 to the Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2016.

	Three months ended September 30,		Nine months ended September 30,	
Risk Management Contracts ($000s)	2016	2015	2016	2015
Realized gain on commodity contracts	14,830	37,299	66,804	128,328
Unrealized loss on commodity contracts	(10,373)	(50,134)	(32,704)	(159,173)
Total gain (loss) on commodity contracts	4,457	(12,835)	34,100	(30,845)
Gain (loss) on interest rate contracts (1)	217	(1,981)	(292)	(11,685)
Total gain (loss) on risk management contracts	4,674	(14,816)	33,808	(42,530)

Note:

(1) The gain (loss) on interest rate risk management contracts are included in interest and financing expense.

At September 30, 2016, the following risk management contracts were outstanding with a mark-to-market asset value of $6.9 million and a mark-to-market liability value of $84.2 million:

WTI Crude Oil Derivative Contracts

Type	**Term**	**Volume (bbls/d)**	**Sold Call Price (US$/bbl) (1)**	**Sold Put Price (US$/bbl) (1)**	**Average Swap Price ($/bbl) (1)**
Swap (2)	2016 Oct – Dec	4,000			C$77.76
Swap	2016 Oct – Dec	8,850			US$49.54
Swap	2017 Jan – Jun	1,000			C$65.00
Swap (3)	2017	10,000			US$50.14
Swap	2018	3,000			US$52.67
Sold put (4)	2016 Oct – Dec	6,000		50.00	
Sold put/call (4)	2017	3,000	85.83	60.00	
Sold put/call (4)	2018	3,000	85.83	60.00	

Notes:

(1) Prices reported are the weighted average prices for the period.

(2) 3,500 bbls/d of Oct – Dec 2016 oil hedges with an average swap price of $97.89/bbl were repriced at $75.00/bbl. The proceeds of $14.5 million were received over the first half of 2016.

(3) 1,500 bbls/d at US$48.00/bbl and 1,500 bbls/d at US$48.05/bbl are extendable through 2018 at the option of the counterparties.

(4) In the third quarter of 2015, Whitecap optimized its previous 6,000 bbls/d sold puts with an average strike price of US$66.68/bbl in 2016 by lowering the strike price to US$50.00/bbl and concurrently sold 2017 and 2018 put and call options with strike prices of US$60.00/bbl and US$85.83/bbl respectively. The optimization was completed on a costless basis.

WTI Crude Oil Derivative Contracts With Locked In Premium

Type	Term	Volume (bbls/d)	Average Swap Price (C$/bbl) [1]
Swap	2016 Oct – Dec	3,500	98.61 [2]
Swap	2016 Oct – Dec	(3,500)	70.18 [2]

Notes:

(1) Prices reported are the weighted average prices for the period.

(2) The offsetting positions result in a locked in premium of $28.43 on 3,500 bbls/d.

WTI Crude Oil Differential Derivative Contracts

Type	Term	Volume (bbls/d)	Basis [1][2]	Average Swap Price (C$/bbl) [3]
Swap	2016 Oct – Dec	11,058	MSW	5.68 [4]
Swap	2016 Oct – Dec	3,000	WCS	19.35 [4]
Swap	2017 Jan – Jun	1,000	MSW	3.29 [4]
Swap	2017 Jan – Jun	1,000	WCS	19.33
Swap	2017	8,000	MSW	4.42 [4]
Swap	2017	1,000	WCS	19.55 [4]

Notes:

(1) Mixed Sweet Blend ("MSW").

(2) Western Canadian Select ("WCS").

(3) Prices reported are the weighted average prices for the period.

(4) Contracts executed in USD were converted to CAD through a foreign exchange contract.

Natural Gas Derivative Contracts

Type	Term	Volume (GJ/d)	Average Swap Price ($/GJ) [1]
Swap	2016 Oct – Dec	30,000	2.72
Swap	2017 Jan – Mar	2,500	3.03
Swap	2017	7,500	2.60

Note:

(1) Prices reported are the weighted average prices for the period.

Power Derivative Contracts

Type	Term	Volume (MWh's)	Fixed Rate ($/MWh) [1]
Swap	2016 Oct – Dec	14,352	46.84
Swap	2017	52,560	43.15
Swap	2018	35,040	48.93

Note:

(1) Prices reported are the weighted average prices for the period.

Interest Rate Contracts

Type	Term		Amount ($000s)	Fixed Rate (%)	Index [1]
Swap	03-Oct-13	03-Oct-18	200,000	2.45	CDOR
Swap	01-May-14	01-May-19	200,000	1.97	CDOR
Swap	02-Mar-15	02-Mar-17	100,000	0.75	CDOR

Note:

(1) Canadian Dollar Offered Rate ("CDOR").

Foreign exchange contracts

Type	Term	Monthly Notional Amount	USD/CAD (1)
Monthly average rate forward	2016 Oct – Dec	US$6.0 million	1.2711
Monthly average rate forward	2017	US$5.0 million	1.2580
Monthly average rate forward	2018 Jan – Jun	US$6.0 million	1.2436
Monthly average rate forward	2018 Jul – Dec	US$5.0 million	1.2459

Note:
(1) Rates reported are the weighted average rates for the period.

Type	Term	Monthly Notional Amount	Floor (1)	Ceiling (1)	Conditional Ceiling (1) (2)
Average rate variable collar	2016 Oct – Dec	US$8.0 million	1.2475	1.3111	1.2622
Average rate variable collar	2017	US$11.0 million	1.2482	1.3188	1.2614
Average rate variable collar	2018 Jan – Jun	US$8.0 million	1.2535	1.3914	1.2858
Average rate variable collar	2018 Jul – Dec	US$12.0 million	1.2500	1.4353	1.3065

Notes:
(1) Rates reported are the weighted average rates for the period.
(2) If the USD/CAD average monthly rate settles above the ceiling rate the settlement amount is based on the conditional ceiling.

Contracts Entered into Subsequent to September 30, 2016

WTI Crude Oil Derivative Contracts

Type	Term	Volume (bbls/d)	Average Swap Price ($/bbl) (1)
Swap	2017 Jan – Jun	2,000	C$69.03
Swap	2017	3,000	C$69.07
Swap	2018	1,000	US$55.10

Note:
(1) Prices reported are the weighted average prices for the period.

WTI Crude Oil Differential Derivative Contracts

Type	Term	Volume (bbls/d)	Basis	Average Swap Price (C$/bbl) (1)
Swap	2017 Jul – Dec	1,000	MSW	3.85
Swap	2017	2,000	MSW	3.85

Note:
(1) Prices reported are the weighted average prices for the period.

Natural Gas Derivative Contracts

Type	Term	Volume (GJ/d)	Average Swap Price ($/GJ) (1)
Swap	2017 Jan – Mar	5,000	3.19
Swap	2017 Jan – Jun	2,500	3.00
Swap	2017	2,500	3.02

Note:
(1) Prices reported are the weighted average prices for the period.

Royalties

($000s, except per boe amounts)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Royalties	27,158	19,873	58,783	61,981
As a % of petroleum and natural gas sales	15	13	14	13
$ per boe	5.99	5.17	4.85	5.60

Royalties as a percentage of sales in the three and nine months ended September 30, 2016 were 15 percent and 14 percent, respectively compared to 13 percent for the same periods in 2015. The increases are primarily attributed to properties acquired in the Southwest Saskatchewan Acquisition, which have higher royalty rates than the Company average partially offset by decreases in royalties due to lower realized prices. Whitecap pays royalties to the provincial governments and landowners in Alberta, Saskatchewan and British Columbia. Each province has separate royalty regimes which impact Whitecap's overall corporate royalty rate.

Operating Expenses

($000s, except per boe amounts)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Operating expenses	41,322	36,655	112,646	109,725
$ per boe	9.12	9.53	9.29	9.91

Operating expenses in the third quarter of 2016 decreased four percent to $9.12 per boe compared to $9.53 per boe in the third quarter of 2015. Year to date, operating expenses decreased six percent to $9.29 per boe compared to $9.91 per boe for the same period in 2015. The decreases in operating expenses per boe are primarily attributed to one-time favourable cost adjustments on acquired properties and lower than estimated thirteenth month adjustments.

Transportation Expenses

($000s, except per boe amounts)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Transportation expenses	3,446	5,772	10,236	17,430
$ per boe	0.76	1.50	0.84	1.57

Transportation expenses in the third quarter of 2016 decreased 49 percent to $0.76 per boe compared to $1.50 per boe in the third quarter of 2015. Year to date, transportation expenses decreased 46 percent to $0.84 per boe compared to $1.57 per boe for the same period in 2015. The decreases in transportation expenses on a per boe basis are primarily attributed to increased pipeline connectivity in west central Saskatchewan and the Deep Basin and properties acquired in the Southwest Saskatchewan Acquisition, which have lower transportation costs than the Company average. The decreases were partially offset by increased transportation expenses at Boundary Lake due to pipeline restrictions primarily in the third quarter of 2016.

Transportation expense per boe will fluctuate quarterly based on pipeline connectivity or downtime, weather, shipper status and pipeline shipping arrangements.

Operating Netbacks

The components of operating netbacks are shown below:

Netbacks ($/boe)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Petroleum and natural gas sales	39.39	40.35	35.16	42.79
Royalties	(5.99)	(5.17)	(4.85)	(5.60)
Operating expenses	(9.12)	(9.53)	(9.29)	(9.91)
Transportation expenses	(0.76)	(1.50)	(0.84)	(1.57)
Operating netbacks prior to hedging	23.52	24.15	20.18	25.71
Realized hedging gain	3.27	9.69	5.51	11.58
Operating netbacks (1)	26.79	33.84	25.69	37.29

Note:
(1) Operating netback is a non-GAAP measure, which is defined under the Non-GAAP Measures section of this MD&A.

Operating netbacks in the third quarter of 2016 decreased 21 percent to $26.79 per boe compared to $33.84 per boe in the third quarter of 2015. The decrease on a per boe basis was primarily due to lower average realized pricing, lower realized hedging gains and higher royalties partially offset by lower operating expenses and transportation expenses. Year to date, operating netbacks decreased 31 percent to $25.69 per boe compared to $37.29 per boe for the same period in 2015. The decrease on a per boe basis was due to lower average realized pricing and realized hedging gains partially offset by lower royalties, operating expenses and transportation expenses.

General and Administrative ("G&A") Expenses

($000s, except per boe amounts)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
G&A	7,243	6,545	19,665	21,303
Capitalized G&A	(1,171)	(1,121)	(3,313)	(5,106)
G&A expenses	6,072	5,424	16,352	16,197
$ per boe	1.34	1.41	1.35	1.46

G&A expenses per boe in the three and nine months ended September 30, 2016 decreased five and eight percent respectively compared to the same periods in 2015. The decreases on a per boe basis were primarily attributed to higher production volumes, which more than offset the absolute increase in G&A expenses.

Share-based and Option-based Awards

($000s, except per boe amounts)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Stock-based compensation	5,724	6,496	22,858	27,750
Capitalized stock-based compensation	(1,749)	(2,130)	(7,302)	(9,758)
Stock-based compensation expenses	3,975	4,366	15,556	17,992
$ per boe	0.88	1.13	1.28	1.62

In the three and nine months ended September 30, 2016, the Company recorded stock-based compensation of $5.7 million and $22.9 million respectively with the offsetting amounts recorded in contributed surplus. Stock-based compensation will fluctuate with changes to the expected payout multipliers associated with the performance awards and additional grants under the Award Incentive Plan.

Award Incentive Plan

The Company implemented an Award Incentive Plan effective April 30, 2013. The Award Incentive Plan has time-based awards and performance awards which may be granted to the directors, officers and employees of the Company. As at September 30, 2016, the maximum number of common shares issuable under the plan shall not at any time exceed 3.755 percent of the total common shares outstanding. Vesting is determined by the Company's Board of Directors. Currently, time-based and performance share awards issued to employees of the Company vest three years from date of grant. Performance awards issued to directors and officers of the Company vest in two tranches with one half of performance awards vesting February 1 of the third year following grant date and one half vesting October 1 of the third year following the grant date.

Each time-based award may entitle the holder to be issued the number of common shares designated in the time-based award (plus dividend equivalents). Performance awards are also subject to a performance multiplier. This multiplier, ranging from zero to two, will be applied on settlement and is dependent on the performance of the Company relative to pre-defined corporate performance measures set by the Board of Directors for the associated period.

A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of shares that vest. Awards are measured at fair value on the date of grant, and the resulting stock-based compensation expense is recognized on a straight-line basis over the vesting period. Upon the exercise of the awards, the associated amount in contributed surplus is recorded as an increase to share capital.

As at September 30, 2016, the Company had 4.3 million awards outstanding.

Stock Options

As at September 30, 2016, the Company had no stock options outstanding. Since the adoption of the new Award Incentive Plan in 2013, there have been no further stock options granted.

Interest and Financing Expenses

	Three months ended September 30,		Nine months ended September 30,	
($000s, except per boe amounts)	2016	2015	2016	2015
Interest and financing expenses	7,274	9,579	23,524	34,434
Unrealized gain (loss) on interest rate contracts	1,493	(846)	3,530	(8,100)
	8,767	8,733	27,054	26,334
$ per boe	1.93	2.27	2.23	2.38

Interest and finance expenses excluding the unrealized gain (loss) on interest rate contracts decreased 15 percent to $1.93 per boe in the third quarter of 2016 compared to $2.27 per boe in the third quarter of 2015. Year to date, interest and finance expenses excluding the unrealized gain (loss) on interest rate contracts decreased six percent to $2.23 per boe compared to $2.38 per boe in the same period in 2015. The decreases on a per boe basis were mainly attributed to higher production volumes.

Depletion, Depreciation, Amortization and Impairment

	Three months ended September 30,		Nine months ended September 30,	
($000s, except per boe amounts)	2016	2015	2016	2015
Depletion, Depreciation, Amortization and Impairment	80,382	567,623	225,399	725,962
Impairment	-	482,261	-	482,261
Depletion, Depreciation, & Amortization ("DD&A")	80,382	85,362	225,399	243,701
$ per boe, before impairment	17.74	22.19	18.59	22.00

DD&A per boe, before impairment in the third quarter of 2016 decreased 20 percent to $17.74 per boe compared to $22.19 per boe in the third quarter of 2015. Year to date, DD&A per boe, before impairment decreased 15 percent to $18.59 per boe compared to $22.00 per boe in the same period in 2015. The decreases on a per boe basis are mainly attributed to lower DD&A rates, reductions in PP&E due to impairment expenses recorded in the second half of 2015 and higher production volumes. The DD&A rate will fluctuate from one period to the next depending on the amount and type of capital spending, the amount of reserves added and production volumes. The depletion rate is calculated on proved and probable oil and natural gas reserves, taking into account the future development costs to produce the reserves.

Exploration and Evaluation ("E&E") Asset Expiries

During the three and nine months ended September 30, 2016, the Company recognized costs associated with expired mineral leases of $0.5 million and $4.6 million as expenses respectively, compared to $0.1 million and $3.6 million in the same periods in 2015, respectively. During the three and nine months ended September 30, 2016, the Company added $0.9 million and $10.9 million of undeveloped land respectively, as a result of property acquisitions completed in the periods.

Net Loss on Asset Dispositions

During the nine months ended September 30, 2016, the Company recognized net losses of $6.2 million on the disposition of non-core assets. The net losses are equal to the difference between the consideration received and the net book value of the assets disposed of by Whitecap.

Taxes

During the three and nine months ended September 30, 2016, the Company recognized a deferred income tax expense of $3.5 million and a deferred income tax recovery of $2.0 million respectively compared to a deferred income tax recovery of $136.5 million and $122.9 million respectively for the same periods in 2015. The deferred income tax recovery in the three and nine months ended September 30, 2015 was primarily due to a $96.1 million deferred income tax recovery recognized as a result of the $355.9 million impairment of PP&E in the third quarter of 2015.

The following gross deductions are available for deferred income tax purposes:

($000s)	September 30, 2016	December 31, 2015
Undepreciated capital cost	446,055	460,897
Canadian development expense	469,193	523,905
Canadian exploration expense	199	-
Canadian oil and gas property expense	1,480,977	1,125,705
Non-capital loss carry forward	919,571	861,874
Share issue costs	54,934	40,498
Total	3,370,929	3,012,879

Net Income (Loss)

In the third quarter of 2016, the Company recognized net income of $6.4 million compared to a net loss of $375.6 million for the third quarter of 2015. The change from a net loss to net income of $382.0 million is primarily attributed to $487.2 million lower DD&A and impairment expenses, $23.3 million higher petroleum and natural gas sales and a $17.3 million change in gains and losses on risk management contracts. The change from a net loss to net income was partially offset by a $140.0 million change in deferred income taxes and $5.8 million in other net changes. The factors causing these changes are discussed in the preceding sections. Year to date 2016, the Company recognized a net loss of $20.4 million compared to a net loss of $413.6 million for the same period in 2015. The decrease of $393.2 million is primarily attributed to $500.6 million lower DD&A and impairment expenses, a $64.9 million change in gains and losses on risk management contracts, $10.9 million lower interest and financing charges and $5.5 million in other net changes. The decrease was partially offset by a $120.9 million change in deferred income taxes, $47.9 million lower petroleum and natural gas sales and a $19.9 million change in net gains and losses on asset dispositions. The factors causing these changes are discussed in the preceding sections.

Funds Flow and Payout Ratios

The following table reconciles cash flow from operating activities (a GAAP measure) to funds flow (a non-GAAP measure) and expenditures on PP&E (a GAAP measure) to development capital (a non-GAAP measure:

	Three months ended September 30,		Nine months ended September 30,	
($000s)	2016	2015	2016	2015
Cash flow from operating activities	89,471	125,840	266,335	390,236
Changes in non-cash working capital	16,855	(10,146)	598	(20,595)
Settlement of decommissioning liabilities	237	376	607	761
Transaction costs	-	10	350	314
Funds flow [(1)]	106,563	116,080	267,890	370,716
Cash dividends declared	25,698	56,014	90,776	156,736
Expenditures on PP&E	33,134	50,613	94,655	172,704
Expenditures on corporate and other assets	(189)	(40)	(313)	(248)
Development capital [(1)]	32,945	50,573	94,342	172,456
Basic payout ratio (%) [(1)]	24	48	34	42
Total payout ratio (%) [(1)]	55	92	69	89
Funds flow per share, basic [(1)]	0.29	0.39	0.81	1.33
Funds flow per share, diluted [(1)]	0.29	0.38	0.81	1.31
Cash dividends declared per share [(1)]	0.07	0.19	0.28	0.56

Note:

(1) Cash dividends declared per share, funds flow, funds flow per share, development capital, basic payout ratio and total payout ratio are non-GAAP measures, which are defined under the Non-GAAP Measures section of this MD&A.

Dividends are only declared once they are approved by the Company's Board of Directors. The Board of Directors reviews Whitecap's ability to pay a dividend on a monthly basis.

Cash flow from operating activities, for the three and nine months ended September 30, 2016, was $89.5 million and $266.3 million respectively compared to $125.8 million and $390.2 million respectively for the same periods in 2015. The decreases in cash flow from operating activities are primarily attributed to decreases in funds flow partially offset by increases in cash inflows due to changes in non-cash working capital.

Funds flow, for the three and nine months ended September 30, 2016, was $106.6 million and $267.9 million respectively compared to $116.1 million and $370.7 million respectively for the same periods in 2015. The decreases in funds flow are primarily attributed to lower operating netbacks partially offset by higher production volumes.

Capital Expenditures

	Three months ended September 30,		Nine months ended September 30,	
($000s)	2016	2015	2016	2015
Land and geological	579	127	775	965
Drilling and completions	28,497	42,101	74,789	128,677
Investment in facilities	2,698	7,224	15,465	37,708
Capitalized administration	1,171	1,121	3,313	5,106
Development capital	32,945	50,573	94,342	172,456
Office and other	189	41	313	250
Property acquisitions	987	86,474	618,522	157,881
Property dispositions	(281)	(12,856)	(144,414)	(26,324)
Corporate acquisitions	-	-	-	579,906
Total capital expenditures	33,840	124,232	568,763	884,169

For the third quarter of 2016, development capital totaled $32.9 million with 95 percent spent on drilling, completions and facilities.

Whitecap drilled 21 (17.9 net) wells in the third quarter of 2016 with a 100 percent success rate, including 2 (2.0 net) horizontal Cardium wells and 1 (1.0 net) horizontal Nisku well in southwest Alberta, 15 (12.4 net) horizontal Viking oil wells in west central Saskatchewan, 1 (1.0 net) Cardium well in northwest Alberta and 2 (1.5 net) wells in southwest Saskatchewan.

Net Property Acquisitions

In the second quarter of 2016, the Company closed the Southwest Saskatchewan Acquisition for cash consideration of $596.3 million. The Company also disposed of non-core assets in Saskatchewan for total cash consideration of $25.1 million.

In the first quarter of 2016, the Company disposed of certain production facilities to a third party for $70 million. Pursuant to the agreement, Whitecap will operate the facilities and will pay the purchaser an annual tariff fee for the life of the agreement and will retain all third party processing revenues generated. Whitecap has the option to repurchase the facilities at any time. The Company also closed an asset swap transaction in which Whitecap received PP&E assets in its west central Saskatchewan core area in exchange for non-core Saskatchewan PP&E assets.

Decommissioning Liability

At September 30, 2016, the Company recorded decommissioning liabilities of $703 million for future abandonment and reclamation of the Company’s properties. Estimates are based on both operational knowledge of the properties and updated industry guidance provided by the Alberta Energy Regulator and the Saskatchewan Ministry of the Economy. The estimates are reviewed quarterly and adjusted as new information regarding the liability is determined.

Capital Resources and Liquidity

Credit Facilities

As at September 30, 2016, the Company had a $1.1 billion credit facility with a syndicate of Canadian banks. The credit facility consists of a $650 million revolving production facility, a $50 million revolving operating facility and a $400 million term loan facility. At the end of the revolving period, being April 30, 2017, the revolving credit facility converts into a 366-day term loan if not renewed. The revolving facilities may be extended for a further 364-day revolving period upon the request of Whitecap, subject to approval by the banks. The credit facility provides that advances may be made by way of direct advances, banker’s acceptances or letters of credit/guarantees. The credit facility bears interest at the bank's prime lending or bankers' acceptance rates plus applicable margins. The applicable margin charged by the bank is dependent upon the Company’s debt to earnings before interest, taxes, depreciation and amortization “EBITDA” ratio for the most recent quarter. The bankers’ acceptances bear interest at the applicable banker’s acceptance rate plus an explicit stamping fee based upon the Company’s Debt to EBITDA ratio. The credit facilities are secured by a fixed and floating charge debenture on the assets of the Company. The first $200 million term loan facility matures on October 3, 2018 and has an effective interest rate of 5.3%. The second $200 million term loan facility matures on May 1, 2019 and has an effective interest rate of 4.7%.

The credit facility has two financial covenants, whereby the Company’s ratio of Debt to EBITDA shall not exceed 4.00:1.00 (1.70:1.00 as at September 30, 2016) and the ratio of EBITDA to interest expense shall not be less than 3.50:1.00 (13.05:1.00 as at September 30, 2016). The EBITDA used in the covenant calculation is adjusted for non-cash items, transaction costs and extraordinary and non-recurring items. The debt used in the covenant calculation includes bank indebtedness, letters of credit and dividends declared. As of September 30, 2016, the Company was compliant with all covenants provided for in the lending agreement. The next review is scheduled on or before April 30, 2017.

Equity

On May 30, 2016, the Company closed a bought deal public financing of approximately 51.1 million subscription receipts at a price of $9.20 per subscription receipt for gross proceeds of approximately $470 million which was used to partially fund the Southwest Saskatchewan Acquisition. Each subscription receipt was converted to one common share on June 23, 2016 with the closing of the Southwest Saskatchewan Acquisition.

On March 15, 2016, the Company closed a bought deal public financing by issuing approximately 13.8 million Whitecap common shares at a price of $6.90 per common share for gross proceeds of approximately $95 million.

On May 1, 2015, as part of the consideration to acquire the issued and outstanding shares of Beaumont Energy Inc. ("Beaumont"), approximately 36.3 million Whitecap shares were issued to Beaumont's shareholders. The common shares issued were valued using the share price of Whitecap on May 1, 2015 of $14.79 per share.

On April 9, 2015, the Company closed a bought deal public financing of approximately 8.1 million subscription receipts at a price of $13.50 per subscription receipt for gross proceeds of approximately $110 million which was used to fund the cash portion of the consideration paid to Beaumont shareholders pursuant to the acquisition of Beaumont and assume Beaumont's debt. Each subscription receipt was converted to one common share on May 1, 2015.

The Company is authorized to issue an unlimited number of common shares. As at November 1, 2016 there were 368.3 million common shares and 4.1 million share awards outstanding.

Liquidity

The Company generally relies on funds flow, equity issuances and its credit facility to fund its capital requirements, dividend payments and provide liquidity. From time to time, the Company accesses capital markets to meet its additional financing needs and to maintain flexibility in funding its capital programs. Future liquidity depends primarily on funds flow, existing credit facilities and the ability to access debt and equity markets. All repayments on the revolving production and operating facilities are due at the term maturity date. Repayment on the term loan facility is due on the term loan maturity date. As none of the facilities mature within the next year, the liabilities are considered to be non-current. The Company generates positive funds flow. At September 30, 2016, the Company had $305 million of unutilized credit to cover any working capital deficiencies. The Company believes that it is well positioned to take advantage of its internally developed opportunities funded through available credit facilities combined with anticipated funds flow. Present sources of capital are currently anticipated to be sufficient to satisfy the Company's previously disclosed 2016 capital program of $175 million and dividend payments for the remainder of the 2016 fiscal year.

Contractual Obligations

Whitecap has contractual obligations in the normal course of business which may include purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, lease rental obligations, employee agreements and debt. These obligations are of a recurring, consistent nature and impact Whitecap's cash flows in an ongoing manner. The Company is committed to future payments under the following agreements:

($000s)	2016	2017	2018	2019+	Total
Operating leases	3,437	14,204	15,404	129,079	162,124
Transportation agreements	6,413	21,271	13,174	29,686	70,544
Bank debt (1)	3,720	409,515	212,759	202,439	828,433
Total	13,570	444,990	241,337	361,204	1,061,101

Note:

(1) These amounts include the notional principal and interest payments.

Related Party Transactions

The Company has retained the law firm of Burnet, Duckworth & Palmer LLP ("BD&P") to provide Whitecap with legal services. A director of Whitecap is a partner of this firm. During the three and nine months ended September 30, 2016, the Company incurred $0.1 million and $0.5 million for legal fees and disbursements, respectively ($0.1 million and $0.5 million for the three and nine months ended September 30, 2015, respectively). These amounts have been recorded at the amounts that have been agreed upon by the two parties. The Company expects to retain the services of BD&P from time to time. As of September 30, 2016, a payable balance of $0.1 million (nil – September 30, 2015) was outstanding.

Changes in Accounting Policies Including Initial Adoption

There were no changes that had a material effect on the reported income (loss) or net assets of the Company.

Standards issued but not yet effective

The Company has reviewed the new and revised accounting pronouncements listed below that have been issued, but are not yet effective. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported income or net assets of the Company.

IFRS 9 Financial Instruments ("IFRS 9") (2013 & 2014)
IFRS 9 (2013) significantly revises the existing hedge accounting guidance in IAS 39 *Financial Instruments: Recognition and Measurement* and is intended to align hedging with an entity's risk management strategies. IFRS 9 (2014) incorporates a further amendment to classification categories for financial assets, and includes a new impairment model. IFRS 9 (2013 & 2014) are effective for annual periods beginning on or after January 1, 2018. Whitecap is currently evaluating the impact of the standards on the Company's consolidated financial statements.

IFRS 15 Revenue from Contracts with Customers ("IFRS 15")
IFRS 15 was issued in May 2014 and replaces IAS 18 *Revenue*, IAS 11 *Construction Contracts* and related interpretations. The standard is required to be adopted either retrospectively or using a modified transaction approach for fiscal years beginning on or after January 1, 2018 with earlier adoption permitted. Whitecap is currently evaluating the impact of the standard on the Company's consolidated financial statements.

IFRS 16 Leases ("IFRS 16")
IFRS 16 was issued in January 2016 and replaces IAS 17 *Leases* and related interpretations. The standard is required to be adopted either retrospectively or by recognising the cumulative effect of initially applying IFRS 16 as an adjustment to opening equity at the date of initial application. IFRS 16 is effective for fiscal years beginning on or after January 1, 2019 with earlier adoption permitted if IFRS 15 *Revenue from Contracts with Customers* has also been adopted. Whitecap is currently evaluating the impact of the standard on the Company's consolidated financial statements.

Off Balance Sheet Arrangements

The Company does not have any special purpose entities nor is it party to any arrangements that would be excluded from the balance sheet other than commitments disclosed in Note 16 to the Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2016.

Critical Accounting Estimates

Whitecap's financial and operating results may incorporate certain estimates including:

- estimated revenues, royalties and operating expenses on production as at a specific reporting date but for which actual revenues and expenses have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion, depreciation and accretion that are based on estimates of oil and gas reserves that the Company expects to recover in the future, commodity prices, estimated future salvage values and estimated future capital costs;
- estimated fair values of derivative contracts that are subject to fluctuation depending upon the underlying commodity prices and foreign exchange rates;
- estimated value of decommissioning liabilities that are dependent upon estimates of future costs, timing of expenditures and the risk-free rate;

- estimated income and other tax liabilities requiring interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time;
- estimated stock-based compensation expense using the Black-Scholes option pricing model;
- estimated fair value of business combinations and goodwill requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates; and
- estimated recoverable amounts are based on estimated proved plus probable reserves, production rates, oil and gas prices, future costs, discount rates and other relevant assumptions.

The Company has hired individuals and consultants who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

Business Risks

Whitecap's exploration and production activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different-sized companies. Whitecap is subject to a number of risks that are also common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, production of oil and gas in commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, stock market volatility, debt service which may limit timing or amount of dividends as well as market price of shares, financial and liquidity risks and environmental and safety risks.

In order to reduce exploration risk, Whitecap employs or contracts highly qualified and motivated professionals who have demonstrated the ability to generate quality proprietary geological and geophysical prospects.

Whitecap has retained an independent engineering consulting firm that assists the Company in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of variable factors and assumptions such as commodity prices, projected production, future production costs and government regulations. Such estimates may vary from actual results.

The Company mitigates its risk related to producing hydrocarbons through the utilization of current technology and information systems. In addition, Whitecap strives to operate the majority of its prospects, thereby maintaining operational control. When the Company does not operate, it relies on its partners in jointly-owned properties to maintain operational control.

Whitecap is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company's control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada–United States currency exchange rate, which in turn responds to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Whitecap uses futures and options contracts to hedge its exposure to the potential adverse impact of commodity price volatility. The primary objective of the risk management program is to provide a measure of stability to Whitecap dividends and its capital development program.

Exploration and production for oil and gas is capital intensive. In addition to funds flow, the Company accesses the equity markets as a source of new capital. In addition, Whitecap utilizes bank financing to support ongoing capital investments, which exposes the Company to fluctuations in interest rates on its bank debt. Funds flow also fluctuates with changing commodity prices. Equity and debt capital are subject to market conditions and availability may increase or decrease from time to time.

Environmental Risks

Oil and gas exploration and production can involve environmental risks such as litigation, physical and regulatory risks. Physical risks include the pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company works hard to understand the sensitivities of the environments in which it operates and its responsibilities from the beginning to the end. It also strives to identify the potential environmental impacts of its new projects in the planning stage and during operations. The Company conducts its operations with high standards in order to protect the environment, its employees and consultants, and the general public. Whitecap maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations. Without such insurance, and if the Company becomes subject to environmental liabilities, the payment of such liabilities could reduce or eliminate its available funds or could exceed the funds the Company has available and result in financial distress.

Summary of Quarterly Results

		2016			2015			2014
($000s, except as noted)	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Financial								
Petroleum and natural gas sales	178,498	135,553	112,106	148,225	155,238	186,178	132,639	194,994
Funds flow [(1)]	106,563	93,330	67,997	111,970	116,080	144,703	109,933	139,089
Basic ($/share)	0.29	0.29	0.22	0.37	0.39	0.51	0.43	0.55
Diluted ($/share)	0.29	0.29	0.22	0.37	0.38	0.50	0.43	0.54
Net income (loss)	6,350	(28,311)	1,605	(87,087)	(375,640)	(8,583)	(29,403)	166,116
Basic ($/share)	0.02	(0.09)	0.01	(0.29)	(1.26)	(0.03)	(0.12)	0.66
Diluted ($/share)	0.02	(0.09)	0.01	(0.29)	(1.26)	(0.03)	(0.12)	0.65
Development capital expenditures	32,945	16,159	45,238	62,322	50,573	45,868	76,015	48,144
Property acquisitions	987	596,244	21,291	94,397	86,474	13,077	58,330	135,787
Property dispositions	(281)	(42,498)	(101,635)	(268)	(12,856)	(10,805)	(2,663)	(104,256)
Corporate acquisitions	-	-	-	-	-	579,906	-	205,209
Total assets	4,798,265	4,827,244	4,091,011	4,183,085	4,146,874	4,580,146	3,894,916	3,869,293
Net debt [(1)]	821,731	869,231	800,302	939,787	842,234	774,825	867,148	798,290
Common shares outstanding (000s)	367,655	367,574	314,403	300,613	298,866	298,599	253,595	253,476
Dividends declared or paid per share (basic)	0.07	0.07	0.14	0.19	0.19	0.19	0.19	0.19
Operational								
Average daily production								
Crude oil (bbls/d)	36,094	26,771	29,561	29,092	28,653	28,416	25,623	24,752
NGLs (bbls/d)	2,991	3,231	3,205	3,130	3,204	2,865	2,689	2,979
Natural gas (Mcf/d)	60,994	62,315	61,547	59,069	59,781	61,441	60,237	59,580
Total (boe/d)	49,251	40,388	43,024	42,067	41,821	41,521	38,351	37,661

Note:
(1) Funds flow and net debt do not have a standardized meaning under GAAP. Refer to non-GAAP measures in this MD&A.

Over the past eight quarters, fluctuations in production volumes and realized commodity prices have impacted the Company's petroleum and natural gas sales and funds flow. Net income has fluctuated due to changes in funds flow, impairment and unrealized derivative gains and losses which fluctuate with the changes in forward commodity prices. Capital expenditures and production volumes have fluctuated over time as a result of the timing of acquisitions and the impact of market conditions on the Company's development capital expenditures.

The following outlines the significant events over the past eight quarters:

In the second quarter of 2016, the Company closed the Southwest Saskatchewan Acquisition for cash consideration of $596.3 million. The purchase price was partially funded through the issuance of approximately 51.1 million subscription receipts at a price of $9.20 per subscription receipt for gross proceeds of approximately $470 million. Each subscription receipt was converted to one common share on June 23, 2016 with the closing of the acquisition.

In the first quarter of 2016, the Company closed a bought deal public financing by issuing approximately 13.8 million Whitecap common shares at a price of $6.90 per common share for gross proceeds of approximately $95 million. Additionally, the Company disposed of certain production facilities to a third party for cash consideration of $70 million.

In the fourth quarter of 2015, the Company increased its working interest in strategic light oil assets located in its Boundary Lake core area for total consideration of $93.4 million. Additionally, as a result of lower forecast benchmark commodity prices at December 31, 2015 compared to December 31, 2014, the Company recognized an impairment of $23.9 million attributed to PP&E.

In the third quarter of 2015, the Company acquired strategic light oil assets located in its Boundary Lake and Wapiti area for total consideration of $81.3 million and disposed of non-core assets in Willesden Green for total consideration of $8.0 million. Additionally, as a result of lower forecast benchmark commodity prices at September 30, 2015 compared to December 31, 2014, the Company recognized impairments of $482.3 million, of which $355.9 million and $126.4 million were attributed to PP&E and goodwill respectively.

In the second quarter of 2015, the Company closed the acquisition of Beaumont by acquiring all of the issued and outstanding common shares of Beaumont for $7.3 million in cash, the issuance of 36.3 million Whitecap common shares and the assumption of Beaumont's debt. Through the acquisition, Whitecap acquired high netback, light oil-weighted Viking properties located in the Kerrobert area of west central Saskatchewan. The purchase price was partially funded through the issuance of approximately 8.1 million subscription receipts at a price of $13.50 per subscription receipt for gross proceeds of approximately $109.5 million in the second quarter of 2015. Each subscription receipt was converted to one common share on closing of the acquisition.

In the first quarter of 2015, the Company acquired strategic light oil assets located in its Deep Basin core area for total consideration of $57.5 million. In addition, the Company's credit facility was increased to $1.2 billion from the previous $1.0 billion.

In the fourth quarter of 2014, the Company acquired a controlling interest in a conventional Nisku light sweet oil pool at Elnora, Alberta for total consideration of $277.2 million. The purchase price was partially funded through the issuance of approximately 7.6 million subscription receipts at a price of $16.55 per subscription receipt for gross proceeds of approximately $125 million in the third quarter of 2014. Each subscription receipt was converted to one common share on closing of the acquisition.

INTERNAL CONTROLS UPDATE

Whitecap is required to comply with National Instrument 52-109 Certification of Disclosure on Issuers' Annual and Interim Filings ("NI 52-109"). NI 52-109 requires that Whitecap disclose in its interim MD&A any material weaknesses in Whitecap's internal control over financial reporting and/or any changes in Whitecap's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect Whitecap's internal controls over financial reporting. Whitecap confirms that no material weaknesses or such changes were identified in Whitecap's internal controls over financial reporting during the third quarter of 2016.

NON-GAAP MEASURES

This MD&A includes non-GAAP measures as further described herein. These non-GAAP measures do not have a standardized meaning prescribed by International Financial Reporting Standards ("IFRS or, alternatively, "GAAP") and therefore may not be comparable with the calculation of similar measures by other companies.

"Development capital" represents expenditures on PP&E excluding corporate and other assets.

"Funds flow" represents cash flow from operating activities adjusted for changes in non-cash working capital, transaction costs and settlement of decommissioning liabilities.

"**Funds flow per share**" represents funds flow divided by the basic or diluted weighted average shares outstanding in the period. Management considers funds flow and funds flow per share to be key measures as they demonstrate Whitecap's ability to generate the cash necessary to pay dividends, repay debt, fund decommissioning liabilities and make capital investments. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, funds flow provides a useful measure of Whitecap's ability to generate cash that is not subject to short-term movements in non-cash operating working capital. Refer to the "Funds Flow and Payout Ratios" section of this report for the reconciliation of cash flow from operating activities to funds flow.

"Operating netbacks" are determined by deducting royalties, production expenses and transportation and selling expenses from oil and gas revenue. Operating netbacks are per boe measures used in operational and capital allocation decisions.

"Cash netbacks" are determined by deducting cash general and administrative and interest expenses from operating netbacks.

"Cash dividends declared per share" represents cash dividends declared per share by Whitecap.

"Basic payout ratio" is calculated as cash dividends declared divided by funds flow.

"Total payout ratio" is calculated as cash dividends declared plus development capital, divided by funds flow.

"Net debt" is calculated as bank debt plus working capital surplus or deficit adjusted for risk management contracts.

The following table reconciles bank debt (a GAAP measure) to net debt (a non-GAAP measure):

($000s)	September 30, 2016	December 31, 2015
Bank debt	795,000	876,166
Current liabilities	145,178	165,922
Current assets	(96,422)	(149,338)
Risk management contracts	(22,025)	47,037
Net debt	821,731	939,787

BOE PRESENTATION

Boe means barrel of oil equivalent. All boe conversions in this MD&A are derived by converting gas to oil at the ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of oil. Boe may be misleading, particularly if used in isolation. A Boe conversion rate of 1 Bbl : 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency ratio of 1 Bbl : 6 Mcf, utilizing a conversion ratio of 1 Bbl : 6 Mcf may be misleading as an indication of value.

FORWARD-LOOKING INFORMATION AND STATEMENTS

Certain statements contained in this MD&A constitute forward-looking statements and are based on Whitecap's beliefs and assumptions based on information available at the time the assumption was made. By its nature, such forward-looking information involves 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. The Company believes 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 such forward-looking statements should not be unduly relied upon.

This MD&A contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "believe", “measure”, “stability”, “depends”, “could”, “sustainability” and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: Whitecap’s future plans and focus, including its plans to provide sustainable monthly dividends and per share growth; Whitecap’s commodity risk management program and the benefits to be obtained therefrom; the amount of future decommissioning liabilities; future liquidity and financial capacity; sources of funding the Company’s capital program and dividends; future dividends and dividend policy; future operating expenses and royalty rates; Whitecap’s ability to fund its current capital program and dividend payments for the remainder of the year, future taxes payable by Whitecap, and Whitecap’s deductions available for deferred income tax purposes.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of Whitecap including, without limitation: that Whitecap will continue to conduct its operations in a manner consistent with past operations; the general continuance or improvement in current industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; the accuracy of the estimates of Whitecap’s reserve and resource volumes; the impact of increasing competition; the general stability of the economic and political environment in which Whitecap operates; the ability of Whitecap to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which the Company has an interest in to operate in a safe, efficient and effective manner; field production and decline rates; the ability to reduce operating costs; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of the Company to secure adequate product transportation; future petroleum and natural gas prices; currency, exchange and interest rates; the continued availability of adequate debt and equity financing and cash flow to fund Whitecap’s planned expenditures; and the ability to maintain dividends. Whitecap believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and 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 information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of Whitecap’s products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in Whitecap’s development plans or by third party operators of Whitecap’s properties; competition from other producers; inability to retain drilling rigs and other services; incorrect assessment of the value of acquisitions; failure to realize the anticipated benefits of acquisitions; delays resulting from or inability to obtain require regulatory approvals; increased debt levels or debt service requirements; inaccurate estimation of Whitecap’s oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time to time in Whitecap’s public disclosure documents (including, without limitation, those risks identified in this MD&A) and may be accessed through the SEDAR website (www.sedar.com).

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and Whitecap does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.