



Management's Discussion and Analysis
For the three and six months ended June 30, 2019

This Management's Discussion and Analysis ("MD&A"), dated August 7, 2019 should be read in conjunction with the unaudited Interim Condensed Consolidated Financial Statements of Paramount Resources Ltd. ("Paramount" or the "Company") as at and for the three and six months ended June 30, 2019 (the "Interim Financial Statements") and Paramount's audited Consolidated Financial Statements as at and for the year ended December 31, 2018 (the "Annual Financial Statements"). Financial information included in this MD&A has been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") and is stated in millions of Canadian dollars, unless otherwise noted. The Company's accounting policies have been applied consistently to all periods presented, except for changes as a result of adopting *IFRS 16 – Leases* ("IFRS 16") effective January 1, 2019, which are described in the Change in Accounting Policies section of this document. Paramount voluntarily changed its accounting policy with respect to the discounting of asset retirement obligations ("ARO") effective December 31, 2018 and, as a result, certain comparative information has been restated in this MD&A. Refer to the Annual Financial Statements for a description of the impact of the change in ARO accounting policy on the Company's financial statements.

The disclosures in this document include forward-looking information, non-GAAP measures and certain oil and gas measures. Readers are referred to the Advisories section of this document concerning such matters. Additional information concerning Paramount, including its Annual Information Form, can be found on the SEDAR website at www.sedar.com.

ABOUT PARAMOUNT

Paramount is an independent, publicly traded, liquids-focused Canadian energy company that explores for and develops both conventional and unconventional petroleum and natural gas resources. The Company also pursues long-term strategic exploration and pre-development plays and holds a portfolio of investments in other entities. Paramount's principal properties are located in Alberta and British Columbia. The Company's Class A Common Shares ("Common Shares") are listed on the Toronto Stock Exchange under the symbol "POU".

The Company's operations are organized into the following three regions:

- the Grande Prairie Region, located in the Peace River Arch area of Alberta, which is primarily focused on Montney developments at Karr and Wapiti;
- the Kaybob Region, located in west-central Alberta, which is primarily focused on Montney and Duvernay developments at Kaybob, Smoky, Pine Creek and Ante Creek; and
- the Central Alberta and Other Region, which includes Duvernay development plays in southern Alberta at Willesden Green and the East Shale Basin, and lands and production in northern Alberta and British Columbia.

Paramount also holds a portfolio of: (i) investments in other entities; (ii) investments in exploration and development stage assets, including oil sands and carbonate bitumen interests held by Paramount's wholly-owned subsidiary Cavalier Energy and prospective shale gas acreage in the Liard and Horn River Basins (the "Shale Gas Project"); and (iii) drilling rigs owned by Paramount's wholly-owned limited partnership, Fox Drilling Limited Partnership.

FINANCIAL AND OPERATING HIGHLIGHTS ⁽¹⁾

	Three months ended June 30		Six months ended June 30	
	2019	2018	2019	2018
FINANCIAL				
Petroleum and natural gas sales	209.2	239.7	455.2	509.5
Net loss ⁽²⁾	(121.0)	(119.0)	(197.7)	(183.6)
<i>Per share – basic & diluted (\$/share)</i>	(0.93)	(0.90)	(1.52)	(1.38)
Cash from operating activities	48.1	52.0	136.6	137.2
<i>Per share – basic & diluted (\$/share)</i>	0.37	0.39	1.05	1.03
Adjusted funds flow	54.2	62.6	154.6	160.3
<i>Per share – basic & diluted (\$/share)</i>	0.41	0.47	1.19	1.20
Total assets ⁽²⁾			4,031.8	4,490.1
Long-term debt			909.7	758.9
Net debt			964.8	853.8
Common shares outstanding (thousands)			130,912	132,759
OPERATIONAL				
Sales volumes				
Natural gas (MMcf/d)	309.7	334.1	308.9	342.5
Condensate and oil (Bbl/d)	23,312	23,815	23,494	24,599
Other NGLs (Bbl/d) ⁽³⁾	6,859	7,242	6,573	7,767
Total (Boe/d)	81,793	86,741	81,546	89,457
Realized prices				
Natural gas revenue (\$/Mcf)	1.76	1.71	2.56	2.16
Condensate and oil revenue (\$/Bbl)	71.02	77.25	67.13	73.58
Other NGLs revenue (\$/Bbl) ⁽³⁾	11.01	27.35	19.35	29.65
Petroleum and natural gas sales (\$/Boe)	28.10	30.37	30.84	31.47
Property, plant and equipment and exploration expenditures	100.3	181.7	204.4	317.7
Net wells drilled	1	22	19	41

(1) Readers are referred to the advisories concerning Non-GAAP measures and Oil and Gas Measures and Definitions in the Advisories section of this document and to the reconciliations of such Non-GAAP measures to their most directly comparable measure under GAAP in the applicable sections of this document. This table contains the following Non-GAAP measures: Adjusted Funds Flow and Net Debt.

(2) 2018 restated, refer to Note 1 and 22 of the Annual Financial Statements.

(3) Other NGLs means ethane, propane and butane.

CONSOLIDATED RESULTS

Net Loss

Paramount recorded a net loss of \$121.0 million for the three months ended June 30, 2019 compared to a net loss of \$119.0 million in the same period in 2018. Significant factors contributing to the change are shown below:

Three months ended June 30	
Net loss – 2018	(119.0)
• Income tax expense in 2019, mainly due to a reduction in Alberta income tax rates, compared to a recovery in 2018	(143.9)
• Lower netback in 2019 mainly due to lower liquids prices and lower sales volumes	(21.5)
• Higher interest and financing costs in 2019	(4.2)
• Gain on commodity contracts in 2019 compared to a loss in 2018	112.2
• Lower depletion and depreciation in 2019 mainly due to a change in depletion rate methodology in the fourth quarter of 2018	49.9
• Gain on the sale of oil and gas assets in 2019 compared to a loss in 2018	3.9
• Other	1.6
Net loss – 2019	(121.0)

Paramount recorded a net loss of \$197.7 million for the six months ended June 30, 2019 compared to a net loss of \$183.6 million in the same period in 2018. Significant factors contributing to the change are shown below:

Six months ended June 30	
Net loss – 2018	(183.6)
• Income tax expense in 2019, mainly due to a reduction in Alberta income tax rates, compared to a recovery in 2018	(151.8)
• Lower netback in 2019, mainly due to lower liquids prices and lower sales volumes, partially offset by higher natural gas prices	(40.2)
• Closure program provision recognized in respect of the Zama field in 2019	(13.4)
• Higher interest and financing costs in 2019	(4.7)
• Lower depletion and depreciation in 2019 mainly due to a change in depletion rate methodology in the fourth quarter of 2018	100.2
• Lower loss on commodity contracts in 2019	87.2
• Lower exploration and evaluation costs in 2019	4.8
• Transaction and reorganization costs in 2018	4.3
• Other	(0.5)
Net loss – 2019	(197.7)

Cash From Operating Activities / Adjusted Funds Flow ⁽¹⁾

The following is a reconciliation of cash from operating activities to adjusted funds flow:

	Three months ended June 30		Six months ended June 30	
	2019	2018	2019	2018
Cash from operating activities	48.1	52.0	136.6	137.2
Change in non-cash working capital	(2.4)	(0.6)	0.7	(4.0)
Transaction and reorganization costs	–	2.1	–	4.3
Geological and geophysical expenses	2.1	3.1	5.1	8.3
Closure cost expenditures	4.4	–	4.4	–
Asset retirement obligations settled	2.0	6.0	7.8	14.5
Adjusted funds flow	54.2	62.6	154.6	160.3
Adjusted funds flow (\$/Boe)	7.28	7.93	10.47	9.90

(1) Refer to the advisories concerning non-GAAP measures in the Advisories section of this document.

Cash from operating activities for the three months ended June 30, 2019 was \$48.1 million compared to \$52.0 million for the same period in 2018. Significant factors contributing to the change are shown below:

Three months ended June 30	
Cash from operating activities – 2018	52.0
• Lower netback in 2019 mainly due to lower liquids prices and lower sales volumes	(21.5)
• Closure program expenditures in respect of the Zama field in 2019	(4.4)
• Higher interest and financing costs in 2019	(4.2)
• Lower payments on commodity contract settlements in 2019	22.0
• Lower asset retirement obligation settlements in 2019	4.0
• Other	0.2
Cash from operating activities – 2019	48.1

Adjusted funds flow was \$54.2 million in the second quarter of 2019 compared to \$62.6 million in the second quarter of 2018. The decrease in adjusted funds flow was primarily due to a lower netback and higher interest expense, partially offset by lower payments on commodity contract settlements.

Cash from operating activities for the six months ended June 30, 2019 was \$136.6 million compared to \$137.2 million for the same period in 2018. Significant factors contributing to the change are shown below:

Six months ended June 30	
Cash from operating activities – 2018	137.2
• Lower netback in 2019, mainly due to lower liquids prices and lower sales volumes, partially offset by higher natural gas prices	(40.2)
• Higher interest and financing costs in 2019	(4.7)
• Closure program expenditures in respect of the Zama field in 2019	(4.4)
• Receipts on commodity contract settlements in 2019 compared to payments in 2018	39.9
• Lower asset retirement obligation settlements in 2019	6.7
• Transaction and reorganization costs in 2018	4.3
• Other	(2.2)
Cash from operating activities – 2019	136.6

Adjusted funds flow was \$154.6 million in the first half of 2019 compared to \$160.3 million in the first half of 2018. The decrease in adjusted funds flow was primarily due to a lower netback and higher interest expense, partially offset by receipts on commodity contract settlements in 2019 compared to payments in 2018.

OPERATING RESULTS

Netback ⁽¹⁾

	Three months ended June 30				Six months ended June 30			
	2019		2018		2019		2018	
	(\$/Boe) ⁽²⁾		(\$/Boe) ⁽²⁾		(\$/Boe) ⁽²⁾		(\$/Boe) ⁽²⁾	
Natural gas revenue	49.5	1.76	52.1	1.71	142.8	2.56	134.0	2.16
Condensate and oil revenue	150.7	71.02	167.4	77.25	285.5	67.13	327.6	73.58
Other NGLs revenue ⁽³⁾	6.9	11.01	18.0	27.35	23.0	19.35	41.7	29.65
Royalty and sulphur revenue	2.1	–	2.2	–	3.9	–	6.2	–
Petroleum and natural gas sales	209.2	28.10	239.7	30.37	455.2	30.84	509.5	31.47
Royalties	(18.7)	(2.51)	(22.4)	(2.84)	(34.0)	(2.31)	(38.4)	(2.37)
Operating expense	(86.8)	(11.66)	(94.8)	(12.01)	(177.2)	(12.01)	(187.1)	(11.56)
Transportation and NGLs processing ⁽⁴⁾	(21.6)	(2.91)	(18.9)	(2.40)	(46.2)	(3.13)	(46.0)	(2.84)
Netback	82.1	11.02	103.6	13.12	197.8	13.39	238.0	14.70
Commodity contract settlements	(2.8)	(0.37)	(24.8)	(3.15)	2.8	0.19	(37.1)	(2.29)
Netback including commodity contract settlements	79.3	10.65	78.8	9.97	200.6	13.58	200.9	12.41

(1) Readers are referred to the advisories concerning Non-GAAP measures in the Advisories section of this document.

(2) Natural gas revenue shown per Mcf.

(3) Other NGLs means ethane, propane and butane.

(4) Includes downstream natural gas, NGLs and oil transportation costs and NGLs fractionation costs.

Petroleum and natural gas sales were \$209.2 million in the second quarter of 2019, a decrease of \$30.5 million from the second quarter of 2018. Petroleum and natural gas sales were \$455.2 million for the six months ended June 30, 2019, a decrease of \$54.3 million compared to the same period in 2018. The decreases were primarily due to lower liquids prices and lower sales volumes, including as a result of the sale of the Resthaven/Jayar properties in 2018, partially offset by higher natural gas prices. Other NGLs revenue decreased in the first half of 2019 primarily due to lower butane prices.

The impact of changes in sales volumes and prices on petroleum and natural gas sales are as follows:

	Natural Gas	Condensate and Oil	Other NGLs	Royalty and Sulphur	Total
Three months ended June 30, 2018	52.1	167.4	18.0	2.2	239.7
Effect of changes in sales volumes	(3.8)	(3.5)	(1.0)	–	(8.3)
Effect of changes in prices	1.2	(13.2)	(10.1)	–	(22.1)
Change in royalty and sulphur revenue	–	–	–	(0.1)	(0.1)
Three months ended June 30, 2019	49.5	150.7	6.9	2.1	209.2

	Natural Gas	Condensate and Oil	Other NGLs	Royalty and Sulphur	Total
Six months ended June 30, 2018	134.0	327.6	41.7	6.2	509.5
Effect of changes in sales volumes	(13.2)	(14.7)	(6.4)	–	(34.3)
Effect of changes in prices	22.0	(27.4)	(12.3)	–	(17.7)
Change in royalty and sulphur revenue	–	–	–	(2.3)	(2.3)
Six months ended June 30, 2019	142.8	285.5	23.0	3.9	455.2

Sales Volumes

	Three months ended June 30											
	Natural Gas (MMcf/d)			Condensate and Oil (Bbl/d)			Other NGLs (Bbl/d)			Total (Boe/d)		
	2019	2018	% Change	2019	2018	% Change	2019	2018	% Change	2019	2018	% Change
Grande Prairie	74.6	82.9	(10)	11,691	11,163	5	1,686	2,499	(33)	25,804	27,483	(6)
Kaybob	153.1	165.0	(7)	8,994	9,622	(7)	2,622	2,402	9	37,127	39,527	(6)
Central Alberta & Other	82.0	86.2	(5)	2,627	3,030	(13)	2,551	2,341	9	18,862	19,731	(4)
Total	309.7	334.1	(7)	23,312	23,815	(2)	6,859	7,242	(5)	81,793	86,741	(6)

Sales volumes in the second quarter of 2019 decreased six percent to 81,793 Boe/d compared to 86,741 Boe/d in the second quarter of 2018. The reduction in sales volumes was primarily due to lower production in the Kaybob and Central Alberta and Other Regions as a result of natural declines and in the Grande Prairie Region due to the disposition of the Resthaven/Jayar properties in the third quarter of 2018. These decreases were partially offset by higher sales volumes at Wapiti in the Grande Prairie Region and Smoky Duvernay in the Kaybob Region as a result of new wells being brought-on production.

The Resthaven/Jayar properties encompassed approximately 201 (152 net) sections of land and had sales volumes of approximately 5,000 Boe/d in the first half of 2018 prior to being sold in the third quarter of 2018.

Sales volumes at Wapiti averaged 3,903 Boe/d in the second quarter of 2019 compared to 488 Boe/d in the second quarter of 2018. Production and sales volumes were intermittent due to commissioning activities at the new third-party Wapiti natural gas processing plant (the "Wapiti Plant"). The Company began flowing test volumes from its Wapiti 9-3 pad in May 2019 and production levels increased through the end of the second quarter as commissioning progressed and additional wells began flowing.

	Six months ended June 30											
	Natural Gas (MMcf/d)			Condensate and Oil (Bbl/d)			Other NGLs (Bbl/d)			Total (Boe/d)		
	2019	2018	% Change	2019	2018	% Change	2019	2018	% Change	2019	2018	% Change
Grande Prairie	76.3	83.3	(8)	11,312	11,600	(2)	1,644	2,449	(33)	25,668	27,938	(8)
Kaybob	151.8	170.1	(11)	9,362	9,815	(5)	2,474	2,520	(2)	37,135	40,678	(9)
Central Alberta & Other	80.8	89.1	(9)	2,820	3,184	(11)	2,455	2,798	(12)	18,743	20,841	(10)
Total	308.9	342.5	(10)	23,494	24,599	(4)	6,573	7,767	(15)	81,546	89,457	(9)

Sales volumes decreased by nine percent to 81,546 Boe/d in the six months ended June 30, 2019 compared to 89,457 Boe/d in the same period in 2018. The decrease was primarily due to lower production in the Kaybob and Central Alberta and Other Regions as a result of natural declines and in the Grande Prairie Region due to the disposition of the Resthaven/Jayar properties. These decreases were partially offset by higher sales volumes at Smoky Duvernay in the Kaybob Region and at Wapiti and Karr in the Grande Prairie Region as a result of new wells being brought-on production.

Sales volumes are expected to increase in the second half of the year at Wapiti, Karr and Kaybob South Duvernay, with fourth quarter sales volumes expected to average between 85,000 Boe/d and 90,000 Boe/d. The Company is reaffirming its annual average production guidance of between 81,000 Boe/d and 85,000 Boe/d.

Commodity Prices

	Three months ended June 30			Six months ended June 30		
	2019	2018	% Change	2019	2018	% Change
Natural Gas						
Paramount average realized price (\$/Mcf)	1.76	1.71	3	2.56	2.16	19
AECO daily spot (\$/GJ)	0.98	1.10	(11)	1.73	1.53	13
AECO monthly index (\$/GJ)	1.11	1.06	5	1.48	1.40	6
Dawn (\$/MMbtu)	3.15	3.61	(13)	3.52	3.71	(5)
NYMEX (US\$/MMbtu)	2.51	2.83	(11)	2.69	2.84	(5)
Malin – monthly index (US\$/MMbtu)	2.18	1.98	10	3.03	2.24	35
Crude Oil						
Paramount average realized condensate & oil price (\$/Bbl)	71.02	77.25	(8)	67.13	73.58	(9)
Edmonton Light Sweet (\$/Bbl)	72.55	77.82	(7)	69.74	73.95	(6)
West Texas Intermediate (US\$/Bbl)	59.84	67.88	(12)	57.33	65.38	(12)
Foreign Exchange						
\$CDN / 1 \$US	1.34	1.29	4	1.33	1.28	4

Paramount's natural gas portfolio consists of sales priced in the Alberta market and approximately 122,000 GJ/d of sales priced at the Dawn, US Midwest and Malin markets and is sold in a combination of daily and monthly contracts. Paramount continues to evaluate opportunities to further diversify its natural gas sales markets. The Company's average realized natural gas prices increased in the first half of 2019 compared to the first half of 2018 mainly as a result of higher AECO and Malin prices in the first quarter of 2019.

Paramount sells its condensate and oil volumes at Edmonton via third-party pipelines, at truck terminals or at the lease. Condensate and oil volumes sold at Edmonton generally receive higher prices than volumes sold at terminals or leases. Sales prices for condensate and oil are based on West Texas Intermediate reference prices, adjusted for transportation, quality and density differentials. The Company's average realized condensate and oil price decreased in the first half of 2019 compared to the same period in 2018 mainly as a result of lower benchmark prices.

Commodity Price Management

From time-to-time Paramount uses financial commodity contracts to manage exposure to commodity price volatility. As at June 30, 2019, the Company had the following financial commodity contracts in place:

Instruments	Aggregate notional	Average fixed price	Fair value	Remaining Term
Oil – NYMEX WTI Swaps (Sale)	16,000 Bbl/d	CDN\$78.05/Bbl	5.9	July 2019 – December 2019
Oil – NYMEX WTI Calls (Sale)	2,000 Bbl/d	CDN\$82.00/Bbl ⁽¹⁾	0.5	July 2019 – December 2019
Oil – NYMEX WTI Swaps (Sale)	4,000 Bbl/d	CDN\$80.11/Bbl	10.3	January 2020 – December 2020
Other			(0.1)	
			16.6	

(1) Paramount sold NYMEX WTI call options for 2,000 Bbl/d of liquids at an exercise price of CDN\$82.00 per barrel, for which the Company is receiving a premium of CDN\$2.65 per barrel.

Changes in the fair value of the Company's financial commodity contracts are as follows:

	Six months ended June 30, 2019	Twelve months ended December 31, 2018
Fair value, beginning of period	64.4	(19.1)
Changes in fair value	(45.0)	7.0
Settlements paid (received)	(2.8)	76.5
Fair value, end of period	16.6	64.4

Royalties

	Three months ended June 30				Six months ended June 30			
	2019	Rate	2018	Rate	2019	Rate	2018	Rate
Royalties	18.7	9.0%	22.4	9.4%	34.0	7.5%	38.4	7.6%
<i>\$/Boe</i>	2.51		2.84		2.31		2.37	

Second quarter royalties were \$18.7 million in 2019 compared to \$22.4 million in the same period in 2018. Royalties for the six months ended June 30, 2019 were \$34.0 million compared to \$38.4 million in the first six months of 2018. Royalties decreased in 2019 primarily as a result of lower liquids prices and lower production, partially offset by higher royalties at Karr in the Grand Prairie Region. Royalty rates at Karr increased in 2019 as the majority of wells had fully utilized their new well royalty incentives.

Operating Expense

	Three months ended June 30			Six months ended June 30		
	2019	2018	% Change	2019	2018	% Change
Operating expense	86.8	94.8	(8)	177.2	187.1	(5)
<i>\$/Boe</i>	11.66	12.01	(3)	12.01	11.56	4

Operating expense decreased \$8.0 million to \$86.8 million in the second quarter of 2019 compared to \$94.8 million in the same period in 2018. Operating expense was \$177.2 million in the first half of 2019 compared to \$187.1 million in the same period in 2018. The decrease in operating expenses in 2019 is primarily due to lower operating costs in the Central Alberta and Other Region as a result of the partial closure of the Zama field and in the Grande Prairie Region as a result of the disposition of the Resthaven/Jayar properties in the third quarter of 2018. These decreases were partially offset by higher operating costs at Wapiti and Karr related to new production.

Transportation and NGLs Processing

	Three months ended June 30			Six months ended June 30		
	2019	2018	% Change	2019	2018	% Change
Transportation and NGLs processing	21.6	18.9	14	46.2	46.0	-
<i>\$/Boe</i>	2.91	2.40	21	3.13	2.84	10

Transportation and NGLs processing was \$21.6 million and \$46.2 million for the three and six months ended June 30, 2019, respectively, compared to \$18.9 million and \$46.0 million for the corresponding periods in 2018. Transportation and NGLs processing costs increased in 2019 as a result of higher costs related to contracted NGLs fractionation and transportation capacity, partially offset by lower transportation costs in the Grande Prairie Region as a result of the Resthaven/Jayar disposition and lower trucking costs at Karr.

Other Operating Items

	Three months ended June 30		Six months ended June 30	
	2019	2018	2019	2018
Depletion and depreciation ⁽¹⁾	(84.7)	(134.6)	(165.4)	(265.6)
Gain (loss) on sale of oil and gas assets ⁽¹⁾	1.7	(2.2)	7.7	5.6
Exploration and evaluation expense	(2.7)	(3.9)	(7.8)	(12.5)

(1) 2018 restated, refer to Note 1 and 22 of the Annual Financial Statements.

Depletion and depreciation expense decreased to \$84.7 million in the second quarter of 2019 compared to \$134.6 million in the second quarter of 2018. Depletion and depreciation expense decreased to \$165.4 million in the six months ended June 30, 2019 compared to \$265.6 million in the same period in 2018. The decrease in depletion and depreciation expense was primarily due to a change in depletion rate methodology adopted in the fourth quarter of 2018.

Exploration and evaluation expense was \$7.8 million for the six months ended June 30, 2019, a decrease of \$4.7 million compared to the same period in 2018, primarily due to lower geological and geophysical costs.

Midstream Transaction

In June 2019, Paramount entered into an agreement to sell its Karr 6-18 natural gas facility (the "6-18 Facility") and related midstream assets located in the Grande Prairie Region for cash proceeds of approximately \$330 million (the "Midstream Transaction"). The assets and liabilities associated with the sale have been presented as held for sale as at June 30, 2019 in the Interim Financial Statements.

The Midstream Transaction closed on August 1, 2019. In connection with the sale, the Company entered into a midstream services agreement that includes a fee-for-service arrangement and a take-or-pay volume commitment that ends approximately 20 years following the completion of an expansion to the facility, which is scheduled to be commissioned in the second half of 2020. Paramount estimates that operating costs at Karr for the remainder of 2019 will increase by approximately \$13.5 million as a result of the processing fee associated with the midstream services agreement. Proceeds from the Midstream Transaction were used to reduce amounts drawn on Paramount's bank credit facility.

INVESTMENTS IN SECURITIES

Paramount holds equity investments in a number of publicly-traded and private corporations as part of its portfolio of investments. The majority of these investments, including Strath Resources Ltd. ("Strath") and MEG Energy Corp. ("MEG"), were received as consideration for properties sold to the entities. Paramount's investments in securities are summarized below:

As at	Market Value ⁽¹⁾	
	June 30, 2019	December 31, 2018
Strath ⁽²⁾	168.5	170.0
MEG	18.6	28.5
Privateco	21.1	21.1
Other ⁽³⁾	16.3	12.1
Total	224.5	231.7

(1) Based on the period-end closing price of publicly traded investments and the book value of remaining investments.

(2) Includes 85 million common shares and 8.5 million warrants of Strath.

(3) Includes investments in Pipestone Energy Corp., Storm Resources Ltd., Canadian Premium Sand Inc. and other public and private corporations.

CORPORATE

	Three months ended June 30		Six months ended June 30	
	2019	2018	2019	2018
General and administrative	(13.5)	(12.4)	(27.2)	(30.6)
Share-based compensation	(2.6)	(5.8)	(7.5)	(11.4)
Interest and financing	(11.1)	(6.9)	(20.3)	(15.6)
Accretion of asset retirement obligations ⁽¹⁾	(14.9)	(14.5)	(29.4)	(28.7)
Closure costs	–	–	(13.4)	–
Deferred income tax (expense) recovery ⁽¹⁾	(102.1)	41.8	(88.2)	63.6

(1) 2018 restated, refer to Note 1 and 22 of the Annual Financial Statements.

General and administrative expense was lower for the six months ended June 30, 2019 compared to the same period in 2018, primarily due to lower staffing levels and administrative costs in the current year as integration activities following two corporate acquisitions in the third quarter of 2017 were substantially completed.

Interest and financing expense was \$20.3 million in the first half of 2019, an increase of \$4.7 million from the first half of 2018, as a result of higher average debt balances in 2019.

In early 2019, the Company made the decision to cease production operations at the Zama field in northern Alberta. This property is included in the Central Alberta and Other Region. Sales volumes at Zama averaged approximately 1,200 Boe/d in the fourth quarter of 2018. The closure program commenced in the first quarter of 2019 and is expected to span approximately twelve months. Paramount completed the full shut-down of area production by the end of June 2019. The closure program will continue through the balance of the year to permanently abandon over 1,000 kilometers of pipelines and suspend all facilities. The Company recognized a provision of \$13.4 million in the first quarter of 2019 in respect of the expected costs of the Zama closure program and incurred \$4.4 million of closure cost expenditures in the second quarter of 2019.

In the second quarter of 2019, deferred income tax expense included \$106.4 million related to a reduction in Alberta income tax rates.

PROPERTY, PLANT AND EQUIPMENT AND EXPLORATION EXPENDITURES

	Three months ended June 30		Six months ended June 30	
	2019	2018	2019	2018
Drilling, completion and tie-ins	69.9	152.6	128.3	265.2
Facilities and gathering	15.9	18.1	23.6	36.6
Karr 6-18 Facility expansion	11.0	1.1	45.5	1.6
Exploration and development capital ⁽¹⁾	96.8	171.8	197.4	303.4
Corporate	0.2	6.8	2.7	5.9
Total capital additions	97.0	178.6	200.1	309.3
Land and property acquisitions	3.3	3.1	4.3	8.4
	100.3	181.7	204.4	317.7
Exploration and development capital by Region ⁽¹⁾				
Grande Prairie	67.2	73.5	134.9	147.8
Kaybob	29.2	87.7	56.6	138.9
Central Alberta and Other	0.4	10.6	5.9	16.7
	96.8	171.8	197.4	303.4

(1) Readers are referred to the advisories concerning Non-GAAP measures in the Advisories section of this document.

Exploration and development capital totaled \$96.8 million in the second quarter of 2019 compared to \$171.8 million in the same period in 2018. Exploration and development capital was \$197.4 million in the first half of 2019 compared to \$303.4 million in the same period in 2018. Expenditures in the first half of 2019 mainly related to drilling and completion programs and facilities projects in the Grande Prairie and Kaybob Regions.

In the Grande Prairie Region, development activities at Wapiti focused on completion operations for 12 (12.0 net) wells on the 5-3 pad, which were drilled in the first quarter of 2019. All 12 wells are scheduled to be completed by the end of the third quarter. This pad is scheduled to be equipped and brought-on production in the fourth quarter of 2019. Development activities at Karr mainly related to completion operations for 5 (5.0 net) Montney wells on the 4-24 pad, which is scheduled to be brought on stream in the third quarter. Paramount has also commenced drilling operations for 3 (3.0 net) new Montney wells on the 1-19 pad, which are scheduled to be completed and brought-on production in the fourth quarter of 2019. Paramount incurred \$45.5 million in the first half of 2019 to further the expansion of the 6-18 Facility, which was not included in the Company's \$350 million base capital budget. Capital expenditures related to the 6-18 Facility expansion were reimbursed on closing of the Midstream Transaction.

In the Kaybob Region, 5 (2.5 net) new wells on the 2-28 pad at Kaybob South Duvernay were drilled between September 2018 and January 2019 and completed in the spring of 2019. These wells were tied-in and brought-on production in late-June 2019. At the Montney Oil development, 4 (4.0 net) new wells were brought-on production in 2019. The Kaybob Region drilling program for 2019 also included an initial appraisal well at the Ante Creek Montney property, which has been completed and is scheduled to be brought-on production in the third quarter.

In the Central Alberta and Other Region, the Company participated in drilling operations for one (0.5 net) well at Birch in northeast British Columbia, which was completed and brought on production in the second quarter of 2019.

The Company continues to expect 2019 annual spending to be in line with its \$350 million base capital budget.

Wells drilled were as follows:

	Three months ended June 30				Six months ended June 30			
	2019		2018		2019		2018	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
Natural gas	1	1	20	18	17	15	38	30
Oil	–	–	4	4	4	4	11	11
Total	1	1	24	22	21	19	49	41

(1) Gross is the number of wells in which Paramount has a working interest.

(2) Net is the aggregate number of wells obtained by multiplying each gross well by Paramount's percentage of working interest.

LIQUIDITY AND CAPITAL RESOURCES

Paramount manages its capital structure to support current and future business plans and periodically adjusts the structure in response to changes in economic conditions and the risk characteristics of the Company's underlying assets and operations. Paramount may adjust its capital structure through a number of means, including by issuing or repurchasing shares, altering debt levels, modifying capital spending programs, acquiring or disposing of assets, and participating in joint ventures, the availability of any such means being dependent upon market conditions.

As at	June 30, 2019	December 31, 2018
Cash and cash equivalents	(19.3)	(19.3)
Accounts receivable	(98.3)	(121.3)
Prepaid expenses and other	(16.1)	(9.6)
Accounts payable and accrued liabilities	188.8	231.2
Adjusted working capital deficit ⁽¹⁾	55.1	81.0
Paramount Facility	909.7	815.0
Net Debt ⁽²⁾	964.8	896.0
Share capital	2,186.1	2,184.6
Retained earnings (accumulated deficit)	(176.5)	21.2
Reserves	26.7	44.7
Total Capital	3,001.1	3,146.5

(1) Adjusted working capital excludes risk management assets and liabilities, current accounts receivable amounts relating to subleases (June 30, 2019 - \$2.0 million, December 31, 2018 - nil) the current portion of asset retirement obligations and other, and assets and liabilities classified as held for sale.

(2) Refer to the advisories concerning non-GAAP measures in the Advisories section of this document.

The change in net debt for the six months ended June 30, 2019 is primarily due to capital expenditures and asset retirement obligation settlements, partially offset by cash flows from operations. Paramount expects to fund its 2019 operations, obligations and capital expenditures with cash flows from operations and available capacity under its bank credit facility.

Paramount Facility

As at June 30, 2019, the Company had a \$1.5 billion financial covenant-based senior secured revolving bank credit facility (the "Paramount Facility"). The maturity date of the Paramount Facility is currently November 16, 2022, which may be extended from time-to-time at the option of Paramount and with the agreement of the lenders.

Paramount had letters of credit outstanding totaling \$36.0 million as at June 30, 2019 that reduce the amount available to be drawn on the Paramount Facility.

Interest Rate Swaps

The Company had the following floating-to-fixed interest rate swaps in place as at June 30, 2019:

Contract Type	Aggregate notional	Maturity Date	Fixed	Reference	Fair value
			Contract Rate		
Interest Rate Swap	\$250 million	January 2023	2.3%	CDOR ⁽¹⁾	(5.5)
Interest Rate Swap	\$250 million	January 2026	2.4%	CDOR ⁽¹⁾	(11.2)
					(16.7)

(1) Canadian Dollar Offered Rate.

In the first quarter of 2019, Paramount entered into interest rate swap arrangements to manage the uncertainty of variable interest rates by fixing the variable component of a portion of the interest on the Company's long-term debt. The Company classified these arrangements as cash flow hedges and has applied hedge accounting. As at June 30, 2019, there were no changes to the critical terms of the hedging relationship and no hedge ineffectiveness was identified.

Share Capital

Paramount implemented a normal course issuer bid program in January 2019 (the "2019 NCIB"). The 2019 NCIB will terminate on the earlier of: (i) January 3, 2020; and (ii) the date on which the maximum number of Common Shares that can be acquired pursuant to the 2019 NCIB are purchased. Purchases of Common Shares under the 2019 NCIB will be effected through the facilities of the TSX or alternative Canadian trading systems at the market price at the time of purchase.

Paramount may purchase up to 7,110,667 Common Shares under the 2019 NCIB. Pursuant to the rules of the TSX, the maximum number of Common Shares that the Company may purchase under the 2019 NCIB in any one day is 96,491 Common Shares. Paramount may also make one block purchase per calendar week which exceeds such daily purchase restriction, subject to the rules of the TSX. Any Common Shares purchased pursuant to the 2019 NCIB will be cancelled by the Company. In July 2019, the Company purchased and cancelled 33,100 Common Shares at a total cost of \$0.2 million under the 2019 NCIB. Any shareholder may obtain, for no charge, a copy of the notice in respect of the 2019 NCIB filed with the TSX by contacting the Company at 403-290-3600.

As at July 31, 2019, Paramount had 130,019,630 Common Shares outstanding (net of 859,688 Common Shares held in trust under the Company's restricted share unit plan) and 11,740,171 options to acquire Common Shares outstanding, of which 3,349,499 options are exercisable.

QUARTERLY INFORMATION

	2019		2018				2017	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Petroleum and natural gas sales	209.2	246.1	207.4	248.5	239.7	269.8	258.9	116.5
Net income (loss) ⁽¹⁾	(121.0)	(76.7)	(170.5)	(13.1)	(119.0)	(64.6)	(103.2)	383.4
<i>Per share – basic (\$/share)</i>	(0.93)	(0.59)	(1.31)	(0.10)	(0.90)	(0.48)	(0.76)	3.42
<i>Per share – diluted (\$/share)</i>	(0.93)	(0.59)	(1.31)	(0.10)	(0.90)	(0.48)	(0.76)	3.39
Cash from operating activities	48.1	88.5	12.4	73.8	52.0	85.2	43.4	49.4
<i>per share – basic & diluted (\$/share)</i>	0.37	0.68	0.10	0.56	0.39	0.64	0.32	0.44
Adjusted funds flow	54.2	100.5	45.5	58.2	62.6	97.6	110.1	45.3
<i>Per share – basic & diluted (\$/share)</i>	0.41	0.77	0.35	0.44	0.47	0.73	0.82	0.40
Sales volumes								
Natural gas (MMcf/d)	309.7	308.0	315.2	303.8	334.1	351.1	359.9	177.2
Condensate and oil (Bbl/d)	23,312	23,679	24,898	22,868	23,815	25,391	26,285	14,845
Other NGLs (Bbl/d)	6,859	6,284	7,059	6,963	7,242	8,298	9,149	4,641
Total (Boe/d)	81,793	81,296	85,495	80,471	86,741	92,203	95,412	49,023
Average realized price								
Natural gas (\$/Mcf)	1.76	3.37	2.73	1.93	1.71	2.59	2.11	1.89
Condensate and oil (\$/Bbl)	71.02	63.26	45.54	79.83	77.25	70.10	66.65	54.30
Other NGLs (\$/Bbl)	11.01	28.55	31.39	32.16	27.35	31.68	30.15	23.05
Total (\$/Boe)	28.10	33.63	26.68	33.57	30.37	32.51	29.49	25.84

(1) Comparative amounts for the first, second and third quarters of 2018 and for 2017 are restated, refer to Note 1 and 22 of the Annual Financial Statements.

Significant Items Impacting Quarterly Results

Quarterly earnings variances include the impacts of changing production volumes and market prices.

- The second quarter 2019 loss includes \$102.1 million of deferred income tax expense, primarily related to a reduction in Alberta income tax rates and a \$27.6 million gain on financial commodity contracts.
- The first quarter 2019 loss includes a \$72.6 million loss on financial commodity contracts.
- The fourth quarter 2018 loss includes a \$502.5 million impairment of petroleum and natural gas assets, partially offset by a \$170.3 million gain on financial commodity contracts.
- The third quarter 2018 loss includes a \$48.8 million gain on the sale of oil and gas assets, primarily related to the sale of the Resthaven/Jayar properties, and a \$31.1 million loss on commodity contracts.
- The second quarter 2018 loss includes an \$84.6 million loss on financial commodity contracts.
- The first quarter 2018 loss includes a \$47.6 million loss on financial commodity contracts.
- The fourth quarter 2017 loss includes a \$184.6 million impairment related to the Company's Shale Gas Project, a \$182.9 million gain related to the Apache Canada Ltd. acquisition and \$121.7 million of aggregate impairment of property, plant and equipment.
- Third quarter 2017 earnings include a \$366.1 million gain related to the Apache Canada Ltd. acquisition and a \$61.8 million gain related to a fair value adjustment in respect of Trilogy Energy Corp. shares held prior to the merger with Trilogy Energy Corp. in September 2017.

OTHER INFORMATION

Contingencies

In the normal course of Paramount's operations, the Company may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty. Paramount does not anticipate that these claims will have a material impact on its financial position.

In 2016, a release occurred from a non-operated pipeline in which the Company owned a 50 percent interest. The operator, and owner of the remaining 50 percent, initiated response, containment and remediation activities ("Response Activities"). Total costs to complete the Response Activities are estimated at approximately \$50 million. Arbitration proceedings have been commenced against the Company and the hearing is scheduled for the third quarter of 2020. It is Paramount's assessment that it is not responsible for the costs of the Response Activities and as a result, no provision has been recorded in the Company's financial statements.

Tax and royalty legislation and regulations, and government interpretation and administration thereof, continually change. As a result, there are often tax and royalty matters under review by relevant government authorities. All tax and royalty filings are subject to subsequent government audit and potential reassessments. Accordingly, the final amounts may differ materially from amounts estimated and recorded.

CHANGE IN ACCOUNTING POLICIES

The Company adopted IFRS 16, which replaced *IAS 17 – Leases* and related interpretations, effective January 1, 2019, utilizing the modified retrospective approach. The modified retrospective approach does not require prior period comparative information to be restated, rather the cumulative effect of the change is recorded as of the date of adoption.

On adoption of IFRS 16, the Company elected to use the following practical expedients permitted under the standard:

- to rely on its previous assessment of whether leases are onerous by applying *IAS 37 – Provisions, Contingent Liabilities and Contingent Assets* ("IAS 37") immediately before the date of initial application as an alternative to performing an impairment review;
- to apply a single discount rate to a portfolio of leases with similar characteristics;
- to account for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases; and
- to account for lease payments as an expense and not recognize a right-of-use ("ROU") asset if the underlying asset is of a low dollar value, as defined by IFRS 16.

As at January 1, 2019, the total carrying value of Paramount's lease liabilities was \$39.3 million. On adoption of IFRS 16, the Company recognized net ROU assets of \$9.5 million and aggregate accounts receivable amounts related to office subleases of \$8.6 million. The unamortized carrying amount of \$17.8 million related to provisions previously recorded in respect of the Company's office leases was applied against the carrying value of the right of ROU asset upon adoption.

The following table summarizes the impact of adopting IFRS 16 on the Company's balance sheet as at January 1, 2019:

As at	December 31, 2018	Effect of change	January 1, 2019
Accounts receivable	121.3	1.7	123.0
Lease receivable	–	6.9	6.9
Property, plant, and equipment, net	2,178.2	9.5	2,187.7
Accounts payable and accrued liabilities	231.2	(7.6)	223.6
Current portion of asset retirement obligations and other	32.0	8.9	40.9
Asset retirement obligations and other	789.3	16.8	806.1

Refer to the Interim Financial Statements for further details on the adoption of IFRS 16.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

During the three months ended June 30, 2019, there was no change in the Company's internal control over financial reporting ("ICFR") that materially affected, or is reasonably likely to materially affect, the Company's ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

ADVISORIES

Forward-looking Information

Certain statements in this document constitute forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as "anticipate", "believe", "estimate", "will", "expect", "plan", "schedule", "intend", "propose", or similar words suggesting future outcomes or an outlook. Forward-looking information in this document includes, but is not limited to:

- expected average sales volumes for 2019 and in the fourth quarter of 2019;
- budgeted capital expenditures and the expectation that 2019 annual spending will be in line with the base capital budget;
- the expected increase in sales volumes (and the liquids component thereof) in the second half of 2019 as additional new wells are brought-on production;
- the expected timing of completion of the Zama closure program;
- planned exploration, development and production activities, including the anticipated timing of bringing new wells on production;
- the timing of commissioning of the 6-18 Facility expansion;
- the projected availability of third party processing facilities;
- expected increases in Karr operating costs in 2019 following the Midstream Transaction;
- expected funding sources for 2019 operations, obligations and capital expenditures;
- the anticipation that legal proceedings will not have a material impact on Paramount's financial position; and
- Paramount's assessment that it is not responsible for the costs of the Response Activities associated with the 2016 non-operated pipeline release.

Such forward-looking information is based on a number of assumptions which may prove to be incorrect. Assumptions have been made with respect to the following matters, in addition to any other assumptions identified in this document:

- future natural gas and liquids prices;
- royalty rates, taxes and capital, operating, general & administrative and other costs;
- foreign currency exchange rates and interest rates;
- general business, economic and market conditions;
- the ability of Paramount to obtain the required capital to finance its exploration, development and other operations and meet its commitments and financial obligations;
- the ability of Paramount to obtain equipment, services, supplies and personnel in a timely manner and at an acceptable cost to carry out its activities;
- the ability of Paramount to secure adequate product processing, transportation, de-ethanization, fractionation, and storage capacity on acceptable terms;
- the ability of Paramount to market its natural gas and liquids successfully to current and new customers;
- the ability of Paramount and its industry partners to obtain drilling success (including in respect of anticipated production volumes, reserves additions, liquids yields and resource recoveries) and operational improvements, efficiencies and results consistent with expectations;
- the timely receipt of required governmental and regulatory approvals;
- the merits of outstanding and pending legal proceedings;
- the application of regulatory requirements respecting abandonment and reclamation; and
- anticipated timelines and budgets being met in respect of drilling programs and other operations (including well completions and tie-ins and the construction, commissioning and start-up of new and expanded facilities).

Although Paramount believes that the expectations reflected in such forward-looking information is reasonable, undue reliance should not be placed on them as Paramount can give no assurance that such expectations will prove to be correct. Forward-looking information is based on expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Paramount and described in the forward-looking information. The material risks and uncertainties include, but are not limited to:

- fluctuations in natural gas and liquids prices;
- changes in foreign currency exchange rates and interest rates;
- the uncertainty of estimates and projections relating to future revenue, future production, reserve additions, liquids yields (including condensate to natural gas ratios), resource recoveries, royalty rates, taxes and costs and expenses;
- the ability to secure adequate product processing, transportation, de-ethanization, fractionation, and storage capacity on acceptable terms;
- operational risks in exploring for, developing and producing, natural gas and liquids;
- the ability to obtain equipment, services, supplies and personnel in a timely manner and at an acceptable cost;
- potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities (including third-party facilities);
- processing, pipeline, de-ethanization, and fractionation infrastructure outages, disruptions and constraints;
- risks and uncertainties involving the geology of oil and gas deposits;
- the uncertainty of reserves and resources estimates;
- general business, economic and market conditions;
- the ability to generate sufficient cash flow from operations and obtain financing to fund planned exploration, development and operational activities and meet current and future commitments and

obligations (including product processing, transportation, de-ethanization, fractionation and similar commitments and obligations);

- changes in, or in the interpretation of, laws, regulations or policies (including environmental laws);
- the ability to obtain required governmental or regulatory approvals in a timely manner, and to enter into and maintain leases and licenses;
- the effects of weather and other factors including wildlife and environmental restrictions which affect field operations and access;
- the timing and cost of future abandonment and reclamation obligations and potential liabilities for environmental damage and contamination;
- uncertainties regarding aboriginal claims and in maintaining relationships with local populations and other stakeholders;
- the outcome of existing and potential lawsuits, regulatory actions, audits and assessments; and
- other risks and uncertainties described elsewhere in this document and in Paramount's other filings with Canadian securities authorities.

The foregoing list of risks is not exhaustive. For more information relating to risks, see the section titled "RISK FACTORS" in Paramount's annual information form for the year ended December 31, 2018 which is available on SEDAR at www.sedar.com. The forward-looking information contained in this document is made as of the date hereof and, except as required by applicable securities law, Paramount undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Non-GAAP Measures

In this document "Adjusted funds flow", "Netback", "Net Debt", "Adjusted working capital" and "Exploration and development capital", collectively the "Non-GAAP Measures", are used and do not have any standardized meanings as prescribed by IFRS.

Adjusted funds flow refers to cash from operating activities before net changes in operating non-cash working capital, geological and geophysical expenses, asset retirement obligation settlements, closure cost expenditures and transaction and reorganization costs. Adjusted funds flow is used to assist management and investors in measuring the Company's ability to fund capital programs and meet financial obligations, including the settlement of asset retirement obligations. Refer to the Consolidated Results section of this MD&A for the calculation thereof. **Netback** equals petroleum and natural gas sales less royalties, operating costs and transportation and NGLs processing costs. Netback is commonly used by management and investors to compare the results of the Company's oil and gas operations between periods. Refer to the Operating Results section of this MD&A for the calculation thereof. **Net Debt** is a measure of the Company's overall debt position after adjusting for certain working capital and other amounts and is used by management to assess the Company's overall leverage position. Refer to the Liquidity and Capital Resources section of this MD&A for the calculation of Net Debt and **Adjusted working capital**. **Exploration and development capital** consists of the Company's spending on wells, infrastructure projects, and other property, plant and equipment and exploration and evaluation assets and excludes spending related to land and property acquisitions and corporate assets. The exploration and development capital measure provides management and investors with information regarding the Company's capital spending on wells and infrastructure projects separate from land and property acquisition activity and corporate expenditures. Refer to the Property, Plant and Equipment and Exploration Expenditures section of this MD&A for the calculation thereof.

The Non-GAAP Measures should not be considered in isolation or construed as alternatives to their most directly comparable measure calculated in accordance with GAAP, or other measures of financial

performance calculated in accordance with GAAP. The Non-GAAP Measures are unlikely to be comparable to similar measures presented by other issuers.

Oil and Gas Measures and Definitions

The term "liquids" includes oil, condensate and Other NGLs (ethane, propane and butane). NGLs consist of condensate and Other NGLs.

Abbreviations

Liquids		Natural Gas	
Bbl	Barrels	Mcf	Thousands of cubic feet
Bbl/d	Barrels per day	MMcf	Millions of cubic feet
NGLs	Natural gas liquids	MMcf/d	Millions of cubic feet per day
Condensate	Pentane and heavier hydrocarbons	GJ	Gigajoule
		GJ/d	Gigajoules per day
		MMbtu	Millions of British thermal units
		AECO	AECO-C reference price
		NYMEX	New York Mercantile Exchange
Oil Equivalent			
Boe	Barrels of oil equivalent		
Boe/d	Barrels of oil equivalent per day		

This MD&A contains disclosures expressed as "Boe", "\$/Boe" and "Boe/d". Natural gas equivalency volumes have been derived using the ratio of six thousand cubic feet of natural gas to one barrel of oil when converting natural gas to Boe. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. For the six months ended June 30, 2019, the value ratio between crude oil and natural gas was approximately 47:1. This value ratio is significantly different from the energy equivalency ratio of 6:1. Using a 6:1 ratio would be misleading as an indication of value.