Third Quarter 2019 Results

Paramount Resources Ltd. Reports Third Quarter 2019 Results

Calgary, Alberta – November 7, 2019

HIGHLIGHTS

- Paramount's sales volumes averaged 81,046 Boe/d in the third quarter of 2019, relatively unchanged from the second quarter. Third quarter liquids sales volumes, however, increased 1,441 Bbl/d to 31,612 Bbl/d (39 percent of total sales) compared to 30,171 Bbl/d (37 percent of total sales) in the second quarter.
- At Wapiti, third quarter sales volumes increased 109 percent to 8,163 Boe/d (74 percent liquids) compared to the second quarter.
- All 11 (11.0 net) Montney wells on the Wapiti 9-3 pad have started-up and are producing at restricted rates largely due to intermittent, but improving, runtime associated with the commissioning of the new third-party Wapiti natural gas processing facility (the "Wapiti Plant"). Under those operating conditions, the 11 wells averaged gross peak 30-day production of 1,198 Boe/d per well, with average CGRs of 378 Bbl/MMcf.(1)
- At the new 5-3 pad in Wapiti, three of 12 (12.0 net) wells were temporarily brought-on production through inline test facilities in late-September. The remaining wells are being flowed on cleanup on a rotational basis to recover completion fluids prior to the installation of permanent surface facilities. Initial flowback results have demonstrated higher production rates than the 9-3 pad.
- At Karr, 5 (5.0 net) new Montney wells were started-up on the 4-24 pad in late-September, averaging 2,027 Boe/d of gross peak 30-day production per well, with an average wellhead CGR of 339 Bbl/MMcf.(1)
- Paramount is increasing its fourth quarter 2019 production guidance to between 87,000 Boe/d and 90,000 Boe/d.
- The Company's third quarter netback was $68.2 million compared to $82.1 million in the second quarter of 2019, mainly due to lower commodity prices and incremental third-party processing fees following the sale of the Karr 6-18 natural gas processing facility (the "6-18 Facility") in August.(2)
- Cash from operating activities was $48.6 million in the third quarter of 2019. Adjusted funds flow was $50.9 million ($0.39 per share).(2)
- Base capital spending totaled $113.1 million for the third quarter and $265.0 million for the nine months ended September 30, 2019, with capital programs at Wapiti and Central Alberta coming in under budget. As a result of capital efficiencies realized to date in the 2019 program, the Company has accelerated drilling operations for 10 (10.0 net) Montney wells at Karr into the fourth quarter of 2019 that were originally scheduled for 2020, while maintaining its 2019 base capital budget at $350 million.(2)
- The Company commenced its first area-based closure ("ABC") abandonment and reclamation project in the third quarter at Hawkeye. Economies of scale gained under the ABC approach have resulted in significantly lower costs than prior estimates. The Company's undiscounted estimated asset retirement obligation was revised down by approximately $140 million from December 31, 2018 to September 30, 2019.

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(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 14 percent (Karr) and 11 percent (Wapiti) and Wellhead Liquids sales volumes are lower by approximately 12 percent (Karr) and 3 percent (Wapiti) due to shrinkage, under normalized operations. Excludes days when the wells did not produce. The production rates and volumes stated are over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. See "Oil and Gas Measures and Definitions" in the Advisories.

(2) Netback, adjusted funds flow and base capital are non-GAAP measures. See "Non-GAAP Measures" in the Advisories.

CORPORATE

- Paramount's natural gas diversification strategy resulted in an average realized natural gas sales price of \$1.58/Mcf in the third quarter, 46 percent higher than average AECO prices.
- In the third quarter of 2019, approximately 65 percent of Paramount's natural gas production was sold at AECO prices. The Company is well positioned to take advantage of the recent strengthening of market fundamentals in Alberta. In October 2019, the Company entered into AECO fixed-price physical contracts to sell 40,000 GJ/d of natural gas at \$2.34/GJ for winter 2019/2020 and 60,000 GJ/d of natural gas at \$1.56/GJ for summer 2020.
- Paramount closed the sale of its Karr 6-18 Facility for net cash proceeds of \$327.6 million in August 2019.
- The Company's long-term debt balance at September 30, 2019 was \$720.9 million. Paramount has a \$1.5 billion bank credit facility that matures in November 2022.
- To date, the Company has purchased and cancelled 2.6 million Paramount common shares under its 2019 normal course issuer bid program (the "2019 NCIB") at a total cost of \$14.4 million. These purchases were mainly funded by the disposition of a portion of the Company's investment in MEG Energy Corp.

REVIEW OF OPERATIONS

Paramount's sales volumes averaged 81,046 Boe/d in the third quarter of 2019, relatively unchanged from the second quarter. Liquids volumes increased to 31,612 Bbl/d (39 percent of total sales) in the third quarter compared to 30,171 Bbl/d (37 percent of total sales) in the second quarter. Liquids-rich production continued to ramp-up at both Wapiti and Kaybob South Duvernay. Third quarter production at Karr and Kaybob was impacted by planned facilities outages as well as the temporary shut-in of certain dry gas wells, as the Company proactively managed seasonally low natural gas prices.

Cash from operating activities was \$48.6 million in the third quarter of 2019 compared to \$48.1 million in the second quarter. Third quarter adjusted funds flow was \$50.9 million (\$0.39 per share) compared to \$54.2 million (\$0.41 per share) in the second quarter of 2019. Adjusted funds flow was impacted by lower realized prices and incremental third-party processing fees following the sale of the Karr 6-18 Facility.

Paramount permanently shut down its dry gas Hawkeye property in late-2018 and its Zama property in the first half of 2019 due to challenging economics. The closure of Zama is expected to reduce the Company's total operating expenses by approximately \$27 million per year. The Company has permanently shut-in approximately 2,100 Boe/d of uneconomic production since the fourth quarter of 2018.

Base capital spending totaled \$113.1 million for the third quarter and \$265.0 million for the nine months ended September 30, 2019, with capital programs at Wapiti and Central Alberta coming in under budget. As a result of capital efficiencies realized to date in the 2019 program, the Company has accelerated drilling operations for 10 (10.0 net) Montney wells at Karr into the fourth quarter of 2019 that were originally scheduled for 2020, while maintaining its 2019 base capital budget at \$350 million.

GRANDE PRAIRIE REGION

Karr

	Q3 2019		Q2 2019	
Sales volumes				
Natural gas (MMcf/d)	**58.3**		68.5	
Condensate and oil (Bbl/d)	**8,712**		8,858	
Other NGLs (Bbl/d)	**1,117**		1,505	
Total (Boe/d)	**19,542**		21,782	
% liquids	***50%***		*48%*	
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*
Petroleum and natural gas sales	**63.3**	***35.24***	72.0	*36.32*
Royalties	**(5.7)**	***(3.15)***	(9.8)	*(4.90)*
Operating expense	**(27.8)**	***(15.47)***	(20.1)	*(10.14)*
Transportation and NGLs processing	**(6.6)**	***(3.66)***	(5.2)	*(2.65)*
	23.2	***12.96***	36.9	*18.63*

Third quarter 2019 sales volumes at Karr averaged 19,542 Boe/d compared to 21,782 Boe/d in the second quarter of 2019. Third quarter production at Karr was impacted for 12 days by scheduled processing facility outages and the temporary shut-in of two wells for approximately six weeks due to offsetting completion activities at the 4-24 pad.

The third quarter decrease in Karr netbacks was mainly the result of lower production, incremental third-party processing fees and higher water disposal costs. Incremental processing fees at the 6-18 Facility represented approximately $2.85 per Boe of third quarter per-unit operating costs for Karr alone and $0.70 per Boe for the Company.

At the 4-24 pad, 5 (5.0 net) new Montney wells were completed and brought-on production in late-September, exhibiting very strong initial performance, averaging 2,027 Boe/d of gross peak 30-day production per well with a CGR of 339 Bbl/MMcf.[(1)] Completion costs for these wells averaged $6.8 million per well compared to budgeted type-well completion costs of $7.7 million.

Paramount has also drilled 3 (3.0 net) new Montney wells on the 1-19 pad, which are scheduled to be brought on-stream late in the fourth quarter. Karr area sales volumes are expected to increase through the balance of the year as new production ramps up on the 4-24 and 1-19 pads.

In the fourth quarter of 2019, the Company commenced drilling operations for 10 (10.0 net) Montney wells that were originally scheduled for 2020. Paramount's focus on continuous improvement resulted in a new pacesetter well drilling cost of approximately $2.9 million, which compares to budgeted Karr type-well drilling costs of $4.0 million per well.

These ten new Karr wells will be completed and brought-on production in 2020, once the third-party midstream operator completes its expansion of the 6-18 Facility. Paramount is also investing in additional water injection facilities in 2020 to add incremental water disposal capacity. As Karr production ramps up, the expansion of the 6-18 Facility is completed and new water injection facilities come on-stream, per-unit operating costs at Karr are expected to decrease.

(1) Production measured at the well head, see table on page 4.

The Company drilled its first Lower Montney well at Karr in 2018, and the 4-24 and 1-19 pads each include one Lower Montney well. The results of these three wells will be incorporated in Paramount's assessment of total Montney well location inventory, in the context of optimizing recoveries and capital efficiencies.

Montney wells at Karr continue to exhibit strong production rates and condensate yields. The following table summarizes the performance of wells on the 4-24 and 1-2 pads, and the 27 wells drilled in the 2016/2017 capital program:

	Peak 30-Day (1)			Cumulative (2)			
	Total	Wellhead Liquids	CGR (3)	Total	Wellhead Liquids	CGR (3)	Days on Production
	(Boe/d)	*(Bbl/d)*	*(Bbl/MMcf)*	*(MBoe)*	*(MBbl)*	*(Bbl/MMcf)*	
4-24 Pad							
00/01-11-065-06W6/0 (4)	1,878	1,271	349	89	59	328	50
00/02-12-065-06W6/0	1,836	1,308	413	83	59	410	50
02/03-12-065-06W6/0	2,029	1,308	302	110	69	280	57
00/04-12-065-06W6/0	2,084	1,320	288	114	69	256	57
00/03-12-065-06W6/0	2,307	1,584	365	139	91	316	64
1-2 Pad							
02/01-26-065-05W6/0	2,108	1,333	287	431	245	220	360
02/04-25-065-05W6/0	1,703	951	211	484	231	152	393
00/02-26-065-05W6/0	2,058	1,286	278	627	351	212	405
00/04-25-065-05W6/0 (4)	1,598	975	261	400	227	219	411
00/01-26-065-05W6/0	1,878	1,180	282	551	301	201	412
2016/2017 Wells							
27 wells (Avg. per well)	1,971	1,186	252	650	333	175	659

(1) Peak 30-Day is the highest daily average production rate over a 30-day consecutive period for each well, measured at the wellhead. Natural gas sales volumes are approximately 14 percent lower and Wellhead Liquids sales volumes are approximately 12 percent lower due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes shown are 30-day peak rates over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. See "Oil and Gas Measures and Definitions" in the Advisories.

(2) Cumulative is the aggregate production measured at the wellhead to October 31, 2019. Natural gas sales volumes are approximately 14 percent lower and Wellhead Liquids sales volumes are approximately 12 percent lower due to shrinkage. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. The production rates and volumes shown are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells.

(3) CGRs calculated by dividing raw Wellhead Liquids volumes by raw wellhead natural gas volumes.

(4) Lower Montney well.

Wapiti

Sales volumes at Wapiti averaged 8,163 Boe/d in the third quarter of 2019, comprised of 13.0 MMcf/d of natural gas and 6,002 Bbl/d of liquids, and generated a netback of $14.2 million ($18.94 per Boe). Intermittent production during the commissioning of the new third-party Wapiti Plant resulted in higher fuel gas and shrink losses. These impacts are expected to diminish as operations at the Wapiti Plant stabilize and throughput increases. Third quarter 2019 capital spending at Wapiti was $61.2 million, focused on completion operations at the 5-3 pad, which came in significantly under budget.

All 11 (11.0 net) wells on the Company's first pad at Wapiti, the 9-3 pad, have been brought- on production. This 11-well pad consists of a six-well block drilled to the south and a five-well block drilled to the north. The north and south blocks are specifically designed to test landing zone and spacing patterns. Completion costs for the 9-3 pad averaged $5.5 million per well, compared to budgeted Wapiti type-well completion costs of $7.8 million.

Initial production rates for these wells were impacted by an extended cycle time between completion operations and initial flowback, tubular limitations and intermittent production due to infrastructure capacity restrictions and commissioning activities at the Wapiti Plant. These early operational challenges have been largely alleviated and runtime and production rates have stabilized. Despite the operational challenges encountered with start-up, these wells have exhibited significantly higher CGRs than third-party offsetting wells which utilized a different completion design. The wells on the 9-3 pad are Paramount's first Wapiti wells fracked with the same completion design as utilized at Karr, which have also exhibited higher long-term production rates and higher CGRs than offsetting third-party wells.

The following table summarizes the performance to date of the 11 Montney wells on the 9-3 pad:

	Peak 30-Day (1)			Cumulative (2)			Days on Production
	Total	Wellhead Liquids	CGR (3)	Total	Wellhead Liquids	CGR (3)	
	(Boe/d)	*(Bbl/d)*	*(Bbl/MMcf)*	*(MBoe)*	*(MBbl)*	*(Bbl/MMcf)*	
9-3 Pad							
02/06-15-068-06W6/0	1,511	1,088	429	66	48	444	50
00/11-27-067-06W6/0	1,360	880	306	95	61	299	90
02/07-15-068-06W6/0	1,192	815	360	112	77	367	133
03/08-15-068-06W6/0	962	689	421	99	72	444	133
02/08-15-068-06W6/0	969	693	418	106	73	369	137
02/10-27-067-06W6/0	1,137	779	363	133	89	337	138
03/10-27-067-06W6/0	1,111	749	345	140	87	274	155
03/07-15-068-06W6/0	1,042	787	514	120	83	374	156
02/09-27-067-06W6/0	1,094	769	394	150	100	333	158
03/09-27-067-06W6/0	1,268	794	279	185	121	315	174
04/09-27-067-06W6/0	1,536	1,102	423	191	123	301	175

(1) Peak 30-Day is the highest daily average production rate over a 30-day consecutive period for each well, measured at the wellhead. Natural gas sales volumes are approximately 11 percent lower and Wellhead Liquids sales volumes are approximately 3 percent lower due to shrinkage under normalized operations. Excludes days when the wells did not produce. The production rates and volumes shown are 30-day peak rates over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. See "Oil and Gas Measures and Definitions" in the Advisories.

(2) Cumulative is the aggregate production measured at the wellhead to October 31, 2019. Natural gas sales volumes are approximately 11 percent lower and Wellhead Liquids sales volumes are approximately 3 percent lower due to shrinkage under normalized operations. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. The production rates and volumes shown are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells.

(3) CGRs calculated by dividing raw Wellhead Liquids volumes by raw wellhead natural gas volumes.

The new 5-3 pad at Wapiti includes 12 (12.0 net) Montney wells. The Company achieved a new pacesetter drill cost of approximately $2.6 million for one of these wells, compared to budgeted type-well drilling costs of $3.5 million per well.

Three of the twelve wells on the 5-3 pad were brought-on production through inline test facilities in late-September, and three additional wells were started-up in October. The remaining wells are also scheduled to flowback on a rotational basis to recover completion fluids and prepare for the installation of permanent surface facilities. Initial flowback results have demonstrated higher initial production rates than the 9-3 pad, primarily due to flowing without tubular restrictions and a shorter cycle time between completion operations and initial flowback. The following table summarizes the initial production results for six of the wells that have produced to date:

	Last Day of Production (1)			Cumulative (2)				Days on Production
	Total	Wellhead Liquids	CGR (3)	Average	Total	Wellhead Liquids	CGR (3)	
	(Boe/d)	*(Bbl/d)*	*(Bbl/MMcf)*	*(Boe/d)*	*(MBoe)*	*(MBbl)*	*(Bbl/MMcf)*	
5-3 Pad								
00/09-28-067-06W6/0	1,893	1,336	400	1,501	9	7	465	6
02/11-27-067-06W6/0	2,042	1,432	391	1,975	23	17	445	12
00/12-27-067-06W6/0	1,869	1,281	363	1,805	24	17	398	14
02/12-27-067-06W6/0	2,064	1,296	281	2,071	33	21	310	16
03/11-27-067-06W6/0	2,620	1,612	267	2,021	46	30	317	23
02/09-28-067-06W6/0	1,538	939	261	1,412	57	36	296	40

(1) Volumes measured on October 31, 2019, or the last day the well was produced. Production measured at the wellhead. Natural gas sales volumes are approximately 11 percent lower and Wellhead Liquids sales volumes are approximately 3 percent lower due to shrinkage under normalized operations. The production rates and volumes shown are over a single day and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. See "Oil and Gas Measures and Definitions" in the Advisories.

(2) Cumulative is the aggregate production measured at the wellhead to October 31, 2019. Natural gas sales volumes are approximately 11 percent lower and Wellhead Liquids sales volumes are approximately 3 percent lower due to shrinkage under normalized operations. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. The production rates and volumes shown are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells.

(3) CGRs calculated by dividing raw Wellhead Liquids volumes by raw wellhead natural gas volumes.

KAYBOB REGION

Kaybob Region sales volumes averaged 34,615 Boe/d (31 percent liquids) in the third quarter of 2019 compared to 37,127 Boe/d (31 percent liquids) in the second quarter of the year. Sales volumes were lower in the third quarter as a result of base declines, scheduled facility outages and the temporary shut-in of dry gas wells due to low gas prices, partially offset by increased production at Kaybob South Duvernay.

Kaybob South Duvernay

At Kaybob South Duvernay, 5 (2.5 net) new wells on the 2-28 pad were drilled between June 2018 and January 2019 and completed in the spring of 2019. These wells were tied-in and brought-on production in June 2019, averaging 1,222 Boe/d of gross peak 30-day production per well, with an average wellhead CGR of 171 Bbl/MMcf.[(1)] To date, these wells have an average cumulative CGR of 158 Bbl/MMcf.[(2)]

Kaybob Smoky Duvernay

In the fourth quarter of 2018, the Company brought 4 (4.0 net) new wells on production on the 10-35 pad at Kaybob Smoky Duvernay through Paramount's Smoky 06-16 gas plant. These wells are continuing to exceed internal type curve estimates. The following table summarizes the performance of the four wells on the 10-35 pad:

(1) Production measured at the wellhead. Natural gas sales volumes are approximately 13 percent lower and Wellhead Liquids sales volumes are approximately 22 percent lower due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes stated are over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. See "Oil and Gas Measures and Definitions" in the Advisories.

(2) CGR means condensate to gas ratio and is calculated by dividing raw Wellhead Liquids volumes by raw wellhead natural gas volumes. The stated CGRs exclude days when the wells did not produce. Average cumulative gross production for five wells: 115 MBoe total production, 56 Mbbls of liquids. In aggregate the five wells have produced for a total of 604 days. CGRs stated are over a short period of time and, therefore, are not necessarily indicative of long-term performance.

	Peak 30-Day (1)			Cumulative (2)			
	Total	Wellhead Liquids	CGR (3)	Total	Wellhead Liquids	CGR (3)	Days on Production
	(Boe/d)	*(Bbl/d)*	*(Bbl/MMcf)*	*(MBoe)*	*(MBbl)*	*(Bbl/MMcf)*	
10-35 Pad							
00/09-25-063-21W5/2	1,150	779	350	210	132	282	319
02/01-25-063-21W5/0	1,303	728	211	332	194	234	324
00/16-25-063-21W5/0	1,452	998	366	237	153	304	343
00/08-25-063-21W5/0	1,345	897	334	289	169	235	370

(1) Peak 30-Day is the highest daily average production rate over a 30-day consecutive period for each well, measured at the wellhead. Natural gas sales volumes are approximately 12 percent lower and Wellhead Liquids sales volumes are approximately 3 percent lower due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes shown are 30-day peak rates over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. See "Oil and Gas Measures and Definitions" in the Advisories.

(2) Cumulative is the aggregate production measured at the wellhead to October 31, 2019. Natural gas sales volumes are approximately 12 percent lower and Wellhead Liquids sales volumes are approximately 3 percent lower due to shrinkage. These wells were produced at restricted rates from time-to-time due to facility and gathering system constraints. The production rates and volumes shown are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells.

(3) CGRs calculated by dividing raw Wellhead Liquids volumes by raw wellhead natural gas volumes.

Ante Creek Montney

The Kaybob Region drilling program for 2019 included an initial Montney appraisal well at Ante Creek. This well was completed and brought-on production in September. Initial production results are encouraging and continue to be evaluated.

CENTRAL ALBERTA AND OTHER REGION

Central Alberta and Other Region sales volumes averaged 18,504 Boe/d in the third quarter of 2019 compared to 18,862 Boe/d in the second quarter of 2019. The Company participated in one (0.5 net) well at Birch in northeast British Columbia, which was completed and brought-on production in the second quarter.

Paramount completed the full shut-down of Zama area production in June 2019. The closure program will continue into 2020 to permanently suspend all facilities and over 2,000 kilometers of pipelines. The closure of Zama is expected to reduce the Company's total operating expenses by approximately $27 million per year.

The Company commenced its first ABC project in the third quarter at Hawkeye. Economies of scale gained under the ABC approach have resulted in significantly lower costs than prior estimates. Paramount will continue to optimize its abandonment and reclamation activities based on the actual experience and knowledge gained from this and other projects and pursue additional opportunities to further reduce costs on an on-going basis. The Company's undiscounted estimated asset retirement obligation was revised from $1.79 billion as at December 31, 2018 to $1.65 billion as at September 30, 2019, and from $807.9 million to $749.1 million on a discounted basis.

GREENHOUSE GAS REDUCTION INITIATIVE

As part of Paramount's commitment to responsible energy development, the Company is participating in greenhouse gas ("GHG") emission reduction programs and investing in new equipment to reduce the emission of GHG from its operations. In addition, the Company has reduced its total emissions with the retirement of three facilities at Zama in 2019.

In the Kaybob and Central Alberta and Other Regions, Paramount has recently completed a GHG project, under budget and ahead of schedule, which included the replacement of approximately 1,700 high-bleed controllers with modern low-bleed units at a total cost of $3.0 million. These low-bleed controllers are expected to eliminate approximately 120,000 tonnes of GHG emissions annually. The project is anticipated to generate approximately $9.0 million in GHG credits under current regulations through 2022.

Planning has also commenced for upgrades to the Company's remaining high-bleed controllers and certain other equipment to reduce emissions of GHGs, including methane, carbon dioxide, and nitrogen oxides.

CORPORATE

Paramount has 16,000 Bbl/d of liquids hedged for the remainder of 2019 at an average price of $78.05/Bbl and 4,000 Bbl/d of liquids for 2020 at an average price of $80.11/Bbl.

Paramount's natural gas diversification strategy includes approximately 122,000 GJ/d of sales under long-term contracts priced at the Dawn, US Midwest and Malin markets. The Company's average realized natural gas sales price for the third quarter of 2019 was $1.58/Mcf, approximately 46 percent higher than average AECO prices.

In the third quarter of 2019, approximately 65 percent of Paramount's natural gas production was sold at AECO prices. The Company is well positioned to take advantage of the recent strengthening of market fundamentals, which have resulted in sharp increases in Alberta natural gas prices. In October 2019, Paramount entered into AECO fixed-price physical contracts to sell 40,000 GJ/d of natural gas at $2.34/GJ for winter 2019/2020 and 60,000 GJ/d of natural gas at $1.56/GJ for summer 2020.

The Company's debt balance at September 30, 2019 was $720.9 million. Paramount has a $1.5 billion bank credit facility that matures in November 2022.

In January 2019, Paramount implemented the 2019 NCIB, under which the Company may purchase up to 7.1 million shares for cancellation. To date, the Company has purchased and cancelled 2.6 million common shares at a total cost of $14.4 million under the 2019 NCIB. These purchases were mainly funded by the disposition of a portion of the Company's investment in MEG Energy Corp.

FINANCIAL AND OPERATING RESULTS [1]

($ millions, except as noted)

	Q3 2019		Q2 2019	
Net income (loss)	**141.0**		(121.0)	
per share – basic and diluted ($/share)	***1.08***		*(0.93)*	
Cash from operating activities	**48.6**		48.1	
Adjusted funds flow	**50.9**		54.2	
per share – basic and diluted ($/share)	***0.39***		*0.41*	
Total assets	**3,771.1**		4,031.8	
Long-term debt	**720.9**		909.7	
Net debt	**777.9**		964.8	
Common shares outstanding *(thousands)*	**130,879**		130,912	
Sales volumes				
Natural gas (MMcf/d)	**296.6**		309.7	
Condensate and oil (Bbl/d)	**24,761**		23,312	
Other NGLs (Bbl/d) [3]	**6,851**		6,859	
Total (Boe/d)	**81,046**		81,793	
% liquids	***39%***		*37%*	
Grande Prairie Region (Boe/d)	**27,927**		25,804	
Kaybob Region (Boe/d)	**34,615**		37,127	
Central Alberta and Other Region (Boe/d)	**18,504**		18,862	
Total (Boe/d)	**81,046**		81,793	
Netback		*$/Boe* [2]		*$/Boe* [2]
Natural gas revenue	**43.1**	***1.58***	49.5	*1.76*
Condensate and oil revenue	**149.7**	***65.73***	150.7	*71.02*
Other NGLs revenue [3]	**6.2**	***9.78***	6.9	*11.01*
Royalty and sulphur revenue	**0.8**	**—**	2.1	—
Petroleum and natural gas sales	**199.8**	***26.80***	209.2	*28.10*
Royalties	**(12.1)**	***(1.62)***	(18.7)	*(2.51)*
Operating expense	**(93.8)**	***(12.58)***	(86.8)	*(11.66)*
Transportation and NGLs processing [4]	**(25.7)**	***(3.45)***	(21.6)	*(2.91)*
Netback	**68.2**	***9.15***	82.1	*11.02*
Commodity contract settlements	**5.7**	***0.76***	(2.8)	*(0.37)*
Netback including commodity contract settlements	**73.9**	***9.91***	79.3	*10.65*
Base Capital [5]				
Grande Prairie Region	**106.6**		56.2	
Kaybob Region	**5.4**		29.2	
Central Alberta and Other Region	**1.1**		0.4	
Total	**113.1**		85.8	
Asset retirement obligations settlements	**3.6**		2.0	

(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. This table contains the following Non-GAAP measures: Net Debt, Netback, Adjusted Funds Flow and Base Capital.
(2) Natural gas revenue presented as $/Mcf.
(3) Other NGLs means ethane, propane and butane.
(4) Includes downstream transportation costs and NGLs fractionation costs.
(5) Excludes spending related to the expansion of the 6-18 Facility prior to its sale, land and property acquisitions and corporate expenditures.

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. The Company's principal properties are located in Alberta and British Columbia. Paramount's Class A common shares are listed on the Toronto Stock Exchange under the symbol "POU".

Paramount's third quarter 2019 results, including Management's Discussion and Analysis and the Company's Consolidated Financial Statements will be made available through Paramount's website at www.paramountres.com and on SEDAR at www.sedar.com.

For further information, please contact:

Paramount Resources Ltd.
J.H.T. (Jim) Riddell, Chairman and President and Chief Executive Officer
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Advisories

Forward-looking Information

Certain statements in this press release 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 press release includes, but is not limited to:

- expected average sales volumes in the fourth quarter of 2019;
- budgeted capital expenditures and the maintenance of the 2019 base capital budget at $350 million;
- the expected increase in sales volumes at Karr for the balance for the year as additional new wells are brought-on production;
- an expected decrease in per unit operating costs at Karr;
- an expected decrease in the impact of higher fuel gas and shrink losses at Wapiti as operations at the Wapiti Plant stabilize and throughput increases;
- the timing of completion of the 6-18 Facility expansion;
- the scheduled completion of the Zama closure program and the anticipated reduction in future operating costs;
- planned GHG reduction measures and expenditures and expected GHG credits; and
- planned exploration, development and production activities, including the anticipated timing of bringing new wells on production.

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 press release:

- 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, 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 application of regulatory requirements respecting abandonment and reclamation, GHG emissions and GHG credits; 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, including third-party facilities).

Although Paramount believes that the expectations reflected in such forward-looking information are reasonable based on the information available at the time of this press release, undue reliance should not be placed on the forward-looking information 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, 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, fractionation, and storage capacity on acceptable terms;
- operational risks in exploring for, developing, producing and transporting natural gas and liquids, including the risk of spills, leaks or blowouts;
- 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 and fractionation infrastructure outages, disruptions and constraints;
- risks and uncertainties involving the geology of oil and gas deposits;
- the uncertainty of reserves 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, 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 obtain 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 press release 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 press release, "Adjusted funds flow", "Netback", "Net debt" and "Base capital", collectively the "Non-GAAP measures", are used and do not have any standardized meanings as prescribed by International Financial Reporting Standards.

"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. Asset retirement settlements are excluded from the calculation of adjusted funds flow because such expenditures are not directly linked to the revenue generating activities of the Company. Paramount manages the timing of expenditures related to asset retirement obligation settlements in accordance with regulatory requirements and its overall approach to settling its asset retirement obligations and, as a result, amounts incurred may vary from period to period. Adjusted funds flow is not intended to represent cash from operating activities, net loss or any other GAAP measure and should not be construed as being an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS. The following is the calculation of adjusted funds flow from the nearest GAAP measure for the three months ended September 30, 2019 and June 30, 2019:

	Q3 2019	Q2 2019
Cash from operating activities	48.6	48.1
Change in non-cash working capital	(8.7)	(2.4)
Geological and geophysical expenses	2.5	2.1
Closure cost expenditures	4.9	4.4
Asset retirement obligations settled	3.6	2.0
Adjusted funds flow	50.9	54.2

“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. The following is the calculation of netback from the nearest GAAP measure for the three months ended September 30, 2019 and June 30, 2019:

	Q3 2019	Q2 2019
Petroleum and natural gas sales	199.8	209.2
Royalties	(12.1)	(18.7)
Operating expense	(93.8)	(86.8)
Transportation and NGLs processing	(25.7)	(21.6)
Netback	68.2	82.1

"Net debt" is a measure of the Company’s overall debt position after adjusting for certain working capital amounts and is used by management to assess the Company’s overall leverage position. The following is the calculation of net debt from the nearest GAAP measure as at September 30, 2019 and June 30, 2019:

As at	September 30, 2019	June 30, 2019
Cash and cash equivalents	(11.1)	(19.3)
Accounts receivable	(91.9)	(98.3)
Prepaid expenses and other	(16.4)	(16.1)
Accounts payable and accrued liabilities	176.4	188.8
Adjusted working capital deficit (1)	57.0	55.1
Paramount Facility	720.9	909.7
Net Debt	777.9	964.8

(1) Adjusted working capital excludes risk management assets and liabilities, current accounts receivable amounts relating to subleases (September 30, 2019 - $2.1 million, June 30, 2019 - $2.0 million) and the current portion of asset retirement obligations and other.

"Base capital" consists of the Company’s spending on wells, infrastructure projects, other property, plant and equipment and exploration and evaluation assets and excludes spending related to the expansion of the 6-18 Facility prior to its sale, 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. The following is a reconciliation of base capital to the nearest GAAP measure for the three months ended September 30, 2019 and June 30, 2019 and for the nine months ended September 30, 2019:

	Three months ended September 30,2019	Three months ended June 30,2019	Nine months ended September 30,2019
Property, plant and equipment and exploration	127.5	100.3	331.9
Karr 6-18 Facility expansion	–	(11.0)	(45.5)
Land and property acquisitions	(1.9)	(3.3)	(6.2)
Corporate	(12.5)	(0.2)	(15.2)
Base capital	113.1	85.8	265.0

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	GJ	Gigajoules
Bbl/d	Barrels per day	GJ/d	Gigajoules per day
MBbl	Thousands of barrels	Mcf	Thousands of cubic feet
NGLs	Natural gas liquids	MMcf	Millions of cubic feet
Condensate	Pentane and heavier hydrocarbons	MMcf/d	Millions of cubic feet per day
		AECO	AECO-C reference price
Oil Equivalent		NYMEX	New York Mercantile Exchange
Boe	Barrels of oil equivalent		
MBoe	Thousands of barrels of oil equivalent		
Boe/d	Barrels of oil equivalent per day		

This press release contains disclosures expressed as "Boe", "$/Boe", "MBoe" 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 nine months ended September 30, 2019, the value ratio between crude oil and natural gas was approximately 53:1. 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.

This press release contains metrics commonly used in the oil and natural gas industry. Each of these metrics is determined by the Company as set out below or elsewhere in this press release. "CGR" means condensate to gas ratio and is calculated by dividing raw Wellhead Liquids volumes by raw wellhead natural gas volumes. ″Wellhead Liquids″ means oil, condensate and other hydrocarbon liquids. CGR does not have a standardized meaning and may not be comparable to similar measures presented by other companies. As such, it should not be used to make comparisons. Management uses oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare the Company's performance over time; however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the performance in previous periods and therefore should not be unduly relied upon.

Management's Discussion and Analysis
For the three and nine months ended September 30, 2019

This Management's Discussion and Analysis ("MD&A"), dated November 6, 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 nine months ended September 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 properties 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]

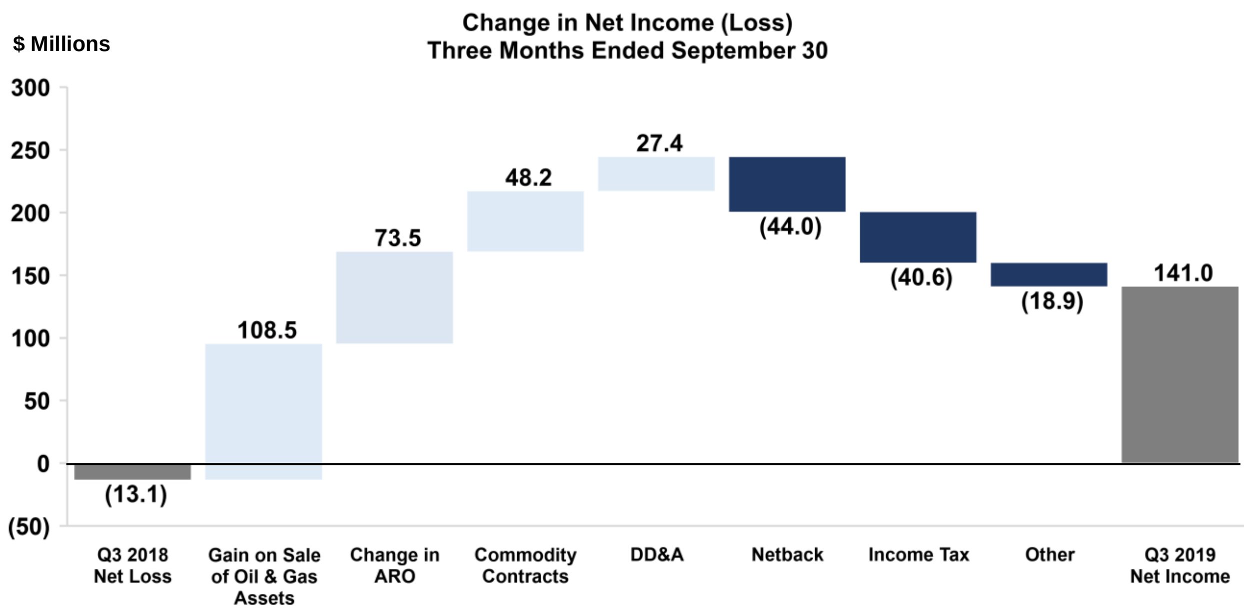
	Three months ended September 30		Nine months ended September 30	
	2019	**2018**	**2019**	**2018**
FINANCIAL				
Petroleum and natural gas sales	**199.8**	248.5	**655.0**	758.0
Net income (loss) [2]	**141.0**	(13.1)	**(56.7)**	(196.7)
Per share – basic & diluted ($/share)	***1.08***	*(0.10)*	***(0.44)***	*(1.48)*
Cash from operating activities	**48.6**	73.8	**185.2**	211.0
Per share – basic & diluted ($/share)	***0.37***	*0.56*	***1.42***	*1.59*
Adjusted funds flow	**50.9**	58.2	**205.5**	218.4
Per share – basic & diluted ($/share)	***0.39***	*0.44*	***1.58***	*1.65*
Total assets [2]			**3,771.1**	4,374.1
Long-term debt			**720.9**	695.1
Net debt			**777.9**	797.3
Common shares outstanding (thousands)			**130,879**	130,994
OPERATIONAL				
Sales volumes				
Natural gas (MMcf/d)	**296.6**	303.8	**304.7**	329.5
Condensate and oil (Bbl/d)	**24,761**	22,868	**23,921**	24,016
Other NGLs (Bbl/d) [3]	**6,851**	6,963	**6,667**	7,496
Total (Boe/d)	**81,046**	80,471	**81,377**	86,429
% Liquids	***39%***	*37%*	***38%***	*36%*
Realized prices				
Natural gas revenue ($/Mcf)	**1.58**	1.93	**2.23**	2.09
Condensate and oil revenue ($/Bbl)	**65.73**	79.83	**66.64**	75.59
Other NGLs revenue ($/Bbl) [3]	**9.78**	32.16	**16.04**	30.43
Petroleum and natural gas sales ($/Boe)	**26.80**	33.57	**29.49**	32.13
Property, plant and equipment and exploration expenditures	**127.5**	135.0	**331.9**	452.7

(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

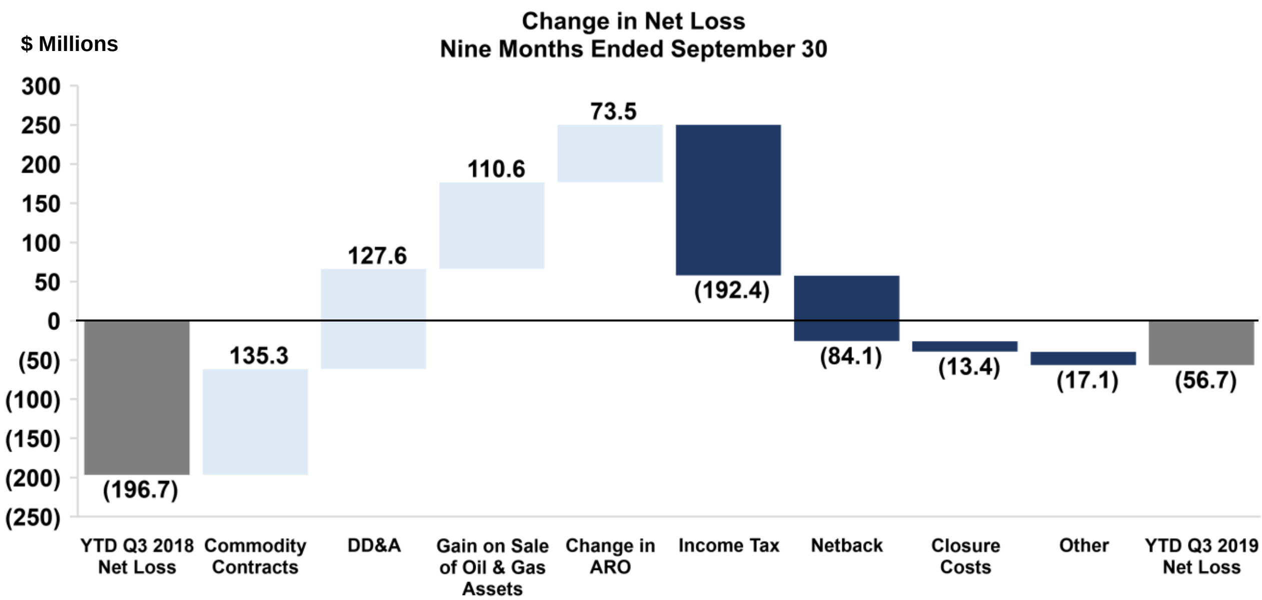
Net Income (Loss)

Paramount recorded net income of $141.0 million for the three months ended September 30, 2019 compared to a net loss of $13.1 million in the same period in 2018, primarily as a result of higher gains on the sale of oil and gas assets, revisions to estimated asset retirement obligations, gains on commodity contracts and lower depletion and depreciation expense, partially offset by a lower netback and deferred income tax expense.



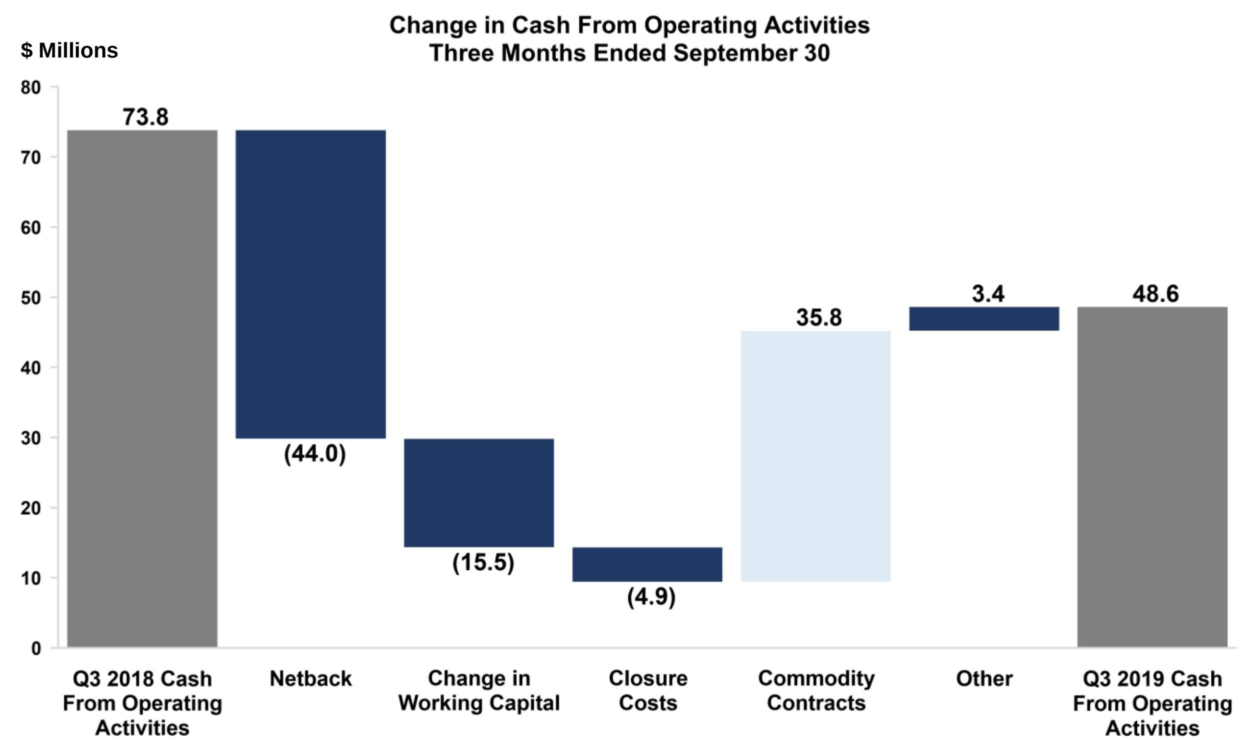
In the third quarter of 2019, Paramount closed the sale of its Karr 6-18 natural gas facility (the "6-18 Facility") and related midstream assets located in the Grande Prairie Region for net cash proceeds of $327.6 million (the "Midstream Transaction"). The cash proceeds included the reimbursement of capital expenditures related to the expansion of the 6-18 Facility. 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 completed in 2020. A gain of $153.7 million was recognized on the sale. Proceeds from the Midstream Transaction were used to reduce amounts drawn on Paramount's bank credit facility (the "Paramount Facility").

Paramount recorded a net loss of $56.7 million for the nine months ended September 30, 2019 compared to a net loss of $196.7 million in the same period in 2018, primarily as a result of a lower loss on commodity contracts, lower depletion and depreciation expense, higher gains on the sale of oil and gas assets and revisions to asset retirement obligations, partially offset by deferred income tax expense and a lower netback.

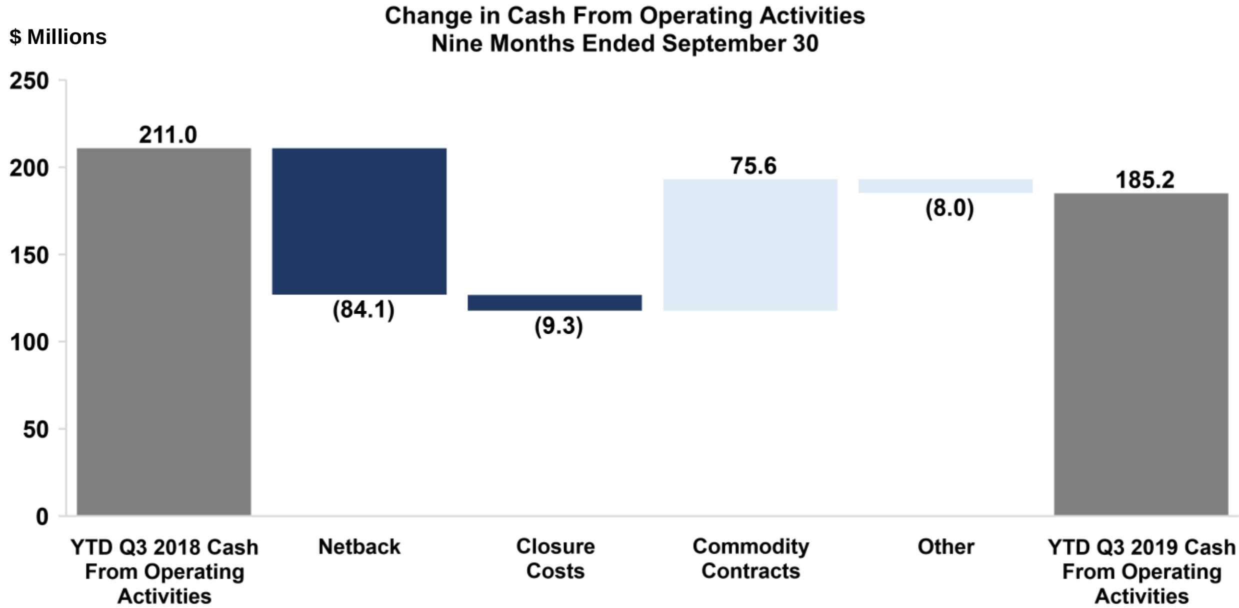


Cash From Operating Activities

Cash from operating activities for the three months ended September 30, 2019 was $48.6 million compared to $73.8 million for the same period in 2018, primarily as a result of a lower netback and changes in non-cash working capital, partially offset by receipts from commodity contracts settlements in 2019.



Cash from operating activities for the nine months ended September 30, 2019 was $185.2 million compared to $211.0 million for the same period in 2018, primarily as a result of a lower netback, partially offset by receipts on commodity contract settlements in 2019.



Adjusted Funds Flow (1)

The following table reconciles cash from operating activities to adjusted funds flow:

	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Cash from operating activities	**48.6**	73.8	**185.2**	211.0
Change in non-cash working capital	**(8.7)**	(24.2)	**(7.9)**	(28.2)
Transaction and reorganization costs	**–**	0.3	**–**	4.5
Geological and geophysical expenses	**2.5**	2.3	**7.5**	10.6
Closure cost expenditures	**4.9**	–	**9.3**	–
Asset retirement obligations settled	**3.6**	6.0	**11.4**	20.5
Adjusted funds flow	**50.9**	58.2	**205.5**	218.4
Adjusted funds flow (*$/Boe*)	***6.83***	*7.86*	***9.25***	*9.26*

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

Adjusted funds flow was $50.9 million in the third quarter of 2019 compared to $58.2 million in the third quarter of 2018. The decrease in adjusted funds flow was primarily due to a lower netback, partially offset by receipts on commodity contract settlements in 2019 compared to payments made in 2018.

Adjusted funds flow was $205.5 million for the nine months ended September 2019 compared to $218.4 million for the same period in 2018. The decrease in adjusted funds flow was primarily due to a lower netback, partially offset by receipts on commodity contract settlements in 2019 compared to payments made in 2018.

OPERATING RESULTS

Netback [1]

	Three months ended September 30				Nine months ended September 30			
	2019		2018		2019		2018	
		($/Boe)[2]		($/Boe)[2]		($/Boe)[2]		($/Boe)[2]
Natural gas revenue	43.1	1.58	53.9	1.93	185.9	2.23	187.9	2.09
Condensate and oil revenue	149.7	65.73	168.0	79.83	435.2	66.64	495.6	75.59
Other NGLs revenue [3]	6.2	9.78	20.6	32.16	29.2	16.04	62.3	30.43
Royalty and sulphur revenue	0.8	–	6.0	–	4.7	–	12.2	–
Petroleum and natural gas sales	199.8	26.80	248.5	33.57	655.0	29.49	758.0	32.13
Royalties	(12.1)	(1.62)	(22.8)	(3.08)	(46.1)	(2.08)	(61.2)	(2.59)
Operating expense	(93.8)	(12.58)	(90.7)	(12.25)	(270.9)	(12.19)	(277.8)	(11.77)
Transportation and NGLs processing [4]	(25.7)	(3.45)	(22.8)	(3.08)	(71.9)	(3.24)	(68.8)	(2.92)
Netback	68.2	9.15	112.2	15.16	266.1	11.98	350.2	14.85
Commodity contract settlements	5.7	0.76	(30.1)	(4.06)	8.5	0.38	(67.1)	(2.85)
Netback including commodity contract settlements	73.9	9.91	82.1	11.10	274.6	12.36	283.1	12.00

(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 $199.8 million in the third quarter of 2019, a decrease of $48.7 million from the third quarter of 2018. Petroleum and natural gas sales were $655.0 million for the nine months ended September 30, 2019, a decrease of $103.0 million compared to the same period in 2018. The decrease in petroleum and natural gas sales in the first nine months of 2019 was 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 2019 primarily due to lower butane and propane prices.

The Resthaven/Jayar properties encompassed approximately 201 (152 net) sections of land, had sales volumes of approximately 5,000 Boe/d in the first half of 2018 and generated a netback of approximately $10 million prior to being sold in the third quarter of 2018.

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 September 30, 2018	53.9	168.0	20.6	6.0	248.5
Effect of changes in sales volumes	(1.3)	13.9	(0.3)	–	12.3
Effect of changes in prices	(9.5)	(32.2)	(14.1)	–	(55.8)
Change in royalty and sulphur revenue	–	–	–	(5.2)	(5.2)
Three months ended September 30, 2019	43.1	149.7	6.2	0.8	199.8

	Natural Gas	Condensate and Oil	Other NGLs	Royalty and Sulphur	Total
Nine months ended September 30, 2018	187.9	495.6	62.3	12.2	758.0
Effect of changes in sales volumes	(14.1)	(2.0)	(6.9)	–	(23.0)
Effect of changes in prices	12.1	(58.4)	(26.2)	–	(72.5)
Change in royalty and sulphur revenue	–	–	–	(7.5)	(7.5)
Nine months ended September 30, 2019	185.9	435.2	29.2	4.7	655.0

Sales Volumes

	Three months ended September 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	**72.1**	61.0	*18*	**14,330**	10,142	*41*	**1,587**	1,142	*39*	**27,927**	21,446	*30*
Kaybob	**144.2**	154.9	*(7)*	**8,130**	9,203	*(12)*	**2,450**	2,429	*1*	**34,615**	37,454	*(8)*
Central Alberta & Other	**80.3**	87.9	*(9)*	**2,301**	3,523	*(35)*	**2,814**	3,392	*(17)*	**18,504**	21,571	*(14)*
Total	**296.6**	303.8	*(2)*	**24,761**	22,868	*8*	**6,851**	6,963	*(2)*	**81,046**	80,471	*1*

Sales volumes in the third quarter of 2019 averaged 81,046 Boe/d compared to 80,471 Boe/d in the third quarter of 2018. The increase in sales volumes in the third quarter was primarily due to higher sales volumes at Wapiti in the Grande Prairie Region and at Smoky Duvernay and South Duvernay in the Kaybob Region as a result of new wells being brought-on production. These increases were offset by lower production in the Kaybob and Central Alberta and Other Regions as a result of natural declines, scheduled maintenance outages at processing facilities, and the closure of the Zama and Hawkeye fields in the Central Alberta and Other Region. Third quarter 2019 production was also impacted by a scheduled processing facility outage which impacted Karr area production for 12 days in July.

Sales volumes at Wapiti increased to an average of 8,163 Boe/d in the third quarter of 2019 compared to 409 Boe/d in the third quarter of 2018. The Company commenced production at the Wapiti 9-3 pad in May 2019 and production levels increased throughout the third quarter as all eleven wells on the pad were started up. Production was intermittent as the commissioning of the new third-party Wapiti natural gas processing facility progressed.

Paramount is increasing its fourth quarter 2019 production guidance to between 87,000 Boe/d and 90,000 Boe/d.

	Nine months ended September 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	**74.9**	75.8	*(1)*	**12,329**	11,109	*11*	**1,625**	2,009	*(19)*	**26,429**	25,750	*3*
Kaybob	**149.2**	165.0	*(10)*	**8,947**	9,609	*(7)*	**2,466**	2,489	*(1)*	**36,286**	39,592	*(8)*
Central Alberta & Other	**80.6**	88.7	*(9)*	**2,645**	3,298	*(20)*	**2,576**	2,998	*(14)*	**18,662**	21,087	*(11)*
Total	**304.7**	329.5	*(8)*	**23,921**	24,016	–	**6,667**	7,496	*(11)*	**81,377**	86,429	*(6)*

Sales volumes decreased six percent to 81,377 Boe/d in the nine months ended September 30, 2019 compared to 86,429 Boe/d in the same period in 2018. The decrease was primarily due to lower production in the Kaybob Region as a result of natural declines, in the Grande Prairie Region due to the disposition of the Resthaven/Jayar properties and in the Central Alberta and Other Region due to the closure of the Zama and Hawkeye fields. These decreases were partially offset by higher sales volumes at Wapiti in the Grande Prairie Region and at Smoky Duvernay and South Duvernay in the Kaybob Region as a result of new wells being brought-on production.

Paramount permanently shut down its dry gas Hawkeye property in late-2018 and its Zama property in the first half of 2019 due to challenging economics. The Company has permanently shut-in approximately 2,100 Boe/d of uneconomic production since the fourth quarter of 2018.

Commodity Prices

	Three months ended September 30			Nine months ended September 30		
	2019	**2018**	% Change	**2019**	**2018**	% Change
Natural Gas						
Paramount average realized price ($/Mcf)	**1.58**	1.93	*(18)*	**2.23**	2.09	*7*
AECO daily spot ($/GJ)	**0.86**	1.11	*(23)*	**1.44**	1.39	*4*
AECO monthly index ($/GJ)	**0.99**	1.28	*(23)*	**1.31**	1.36	*(4)*
Dawn ($/MMbtu)	**2.83**	3.81	*(26)*	**3.29**	3.75	*(12)*
NYMEX (US$/MMbtu)	**2.33**	2.86	*(19)*	**2.57**	2.85	*(10)*
Malin – monthly index (US$/MMbtu)	**1.97**	2.39	*(18)*	**2.68**	2.29	*17*
Crude Oil						
Paramount average realized condensate & oil price ($/Bbl)	**65.73**	79.83	*(18)*	**66.64**	75.59	*(12)*
Edmonton Light Sweet ($/Bbl)	**69.26**	75.64	*(8)*	**69.58**	74.52	*(7)*
West Texas Intermediate (US$/Bbl)	**56.47**	69.46	*(19)*	**57.04**	66.74	*(15)*
Foreign Exchange						
$CDN / 1 $US	**1.32**	1.31	*1*	**1.33**	1.29	*3*

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 decreased in the third quarter of 2019 compared to the third quarter of 2018 mainly as a result of lower benchmark prices.

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 prices decreased in the three and nine months ended September 2019 compared to the same periods 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 September 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	**10.0**	October 2019 – December 2019
Oil – NYMEX WTI Calls (Sale)	2,000 Bbl/d	CDN$82.00/Bbl (1)	**0.5**	October 2019 – December 2019
Oil – NYMEX WTI Swaps (Sale)	4,000 Bbl/d	CDN$80.11/Bbl	**17.4**	January 2020 – December 2020
Other			**0.1**	
			28.0	

(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:

	Nine months ended September 30, 2019	Twelve months ended December 31, 2018
Fair value, beginning of period	**64.4**	(19.1)
Changes in fair value	**(27.9)**	7.0
Settlements paid (received)	**(8.5)**	76.5
Fair value, end of period	**28.0**	64.4

In October 2019, the Company entered into AECO fixed-price physical contracts to sell 40,000 GJ/d of natural gas at a price of $2.34/GJ from December 2019 to March 2020 and 60,000 GJ/d of natural gas at a price of $1.56/GJ from April 2020 to October 2020.

Royalties

	Three months ended September 30				Nine months ended September 30			
	2019	**Rate**	**2018**	Rate	**2019**	**Rate**	**2018**	Rate
Royalties	**12.1**	**6.1%**	22.8	9.4%	**46.1**	**7.1%**	61.2	8.2%
$/Boe	***1.62***		*3.08*		***2.08***		*2.59*	

Third quarter royalties decreased to $12.1 million in 2019 compared to $22.8 million in the same period in 2018. Royalties for the nine months ended September 30, 2019 were $46.1 million compared to $61.2 million in the first nine 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 and Wapiti in the Grande Prairie Region.

Operating Expense

	Three months ended September 30			Nine months ended September 30		
	2019	**2018**	% Change	**2019**	**2018**	% Change
Operating expense	**93.8**	90.7	*3*	**270.9**	277.8	*(2)*
$/Boe	***12.58***	*12.25*	*3*	***12.19***	*11.77*	*4*

Operating expense increased $3.1 million to $93.8 million in the third quarter of 2019 compared to $90.7 million in the same period in 2018. Operating expense was $270.9 million in the nine months ended September 30, 2019 compared to $277.8 million in the same period in 2018. The decrease in operating expenses for the nine months ended September 30, 2019 is primarily due to lower operating costs in the Central Alberta and Other and Kaybob Regions as a result of lower well workover and maintenance activity and the closure of the Zama field. Operating costs in the Grande Prairie Region were also reduced 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 related to new production and incremental natural gas processing fees at Karr following the Midstream Transaction.

Transportation and NGLs Processing

	Three months ended September 30			Nine months ended September 30		
	2019	**2018**	% Change	**2019**	**2018**	% Change
Transportation and NGLs processing	**25.7**	22.8	13	**71.9**	68.8	5
$/Boe	***3.45***	*3.08*	*12*	***3.24***	*2.92*	*11*

Transportation and NGLs processing was $25.7 million and $71.9 million for the three and nine months ended September 30, 2019, respectively, compared to $22.8 million and $68.8 million for the corresponding periods in 2018. Transportation and NGLs processing costs increased in 2019 as a result of new production at Wapiti and higher 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 in the third quarter of 2018.

Other Operating Items

	Three months ended September 30		Nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Depletion and depreciation [(1)]	**(83.3)**	(110.7)	**(248.7)**	(376.3)
Gain on sale of oil and gas assets [(1)]	**157.3**	48.8	**165.0**	54.4
Exploration and evaluation expense	**(10.3)**	(2.9)	**(18.0)**	(15.4)

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

Depletion and depreciation expense was $83.3 million and $248.7 million for the three and nine months ended September 30, 2019, respectively, compared to $110.7 million and $376.3 million for the corresponding periods in 2019. The decrease in depletion and depreciation expense was primarily due to the modification of the Company's depletion methodology in the fourth quarter of 2018.

The gain on sale of $157.3 million for the three months ended September 30, 2019 mainly relates to the Midstream Transaction. In July 2018, Paramount sold its oil and gas properties and related infrastructure at Resthaven/Jayar in the Grande Prairie Region for gross proceeds of $340 million, resulting in the recognition of a gain on sale of $47.5 million. Total consideration included $170 million in cash, 85 million common shares of Strath Resources Ltd. ("Strath") and 8.5 million warrants to acquire Strath common shares at an exercise price of $2.00 per share.

INVESTMENTS IN SECURITIES

As at	September 30 2019	December 31 2018
Level one fair value hierarchy securities	**87.0**	36.0
Level three fair value hierarchy securities	**68.8**	195.7
	155.8	231.7

Investments that are categorized as level one fair value hierarchy securities are carried at their period-end value based on the trading prices of the security quoted in an active market. Estimates of fair value for investments that are categorized as level three fair value hierarchy securities are based on valuation techniques that incorporate unobservable inputs. The valuation techniques utilize market-based metrics of comparable companies and transactions, indications of value based on equity transactions of the entities and other indicators of value. Fair value estimates of level three fair value hierarchy securities are updated at each balance sheet date to confirm whether the carrying value of each investment continues to fall within a range of possible fair values indicated by such techniques. At September 30, 2019, the Company recorded a $118.1 million charge to other comprehensive income as a result of updates to fair value range estimates for level three fair value hierarchy securities. Other expense for the nine months ended September 30, 2019 includes $8.8 million related to the estimated change in fair value of Strath Resources Ltd. warrants.

CORPORATE

	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
General and administrative	**(12.8)**	(11.2)	**(40.0)**	(41.8)
Share-based compensation	**(6.8)**	(5.5)	**(14.3)**	(16.9)
Interest and financing	**(9.7)**	(6.7)	**(30.0)**	(22.3)
Accretion of asset retirement obligations (1)	**(15.1)**	(14.5)	**(44.5)**	(43.2)
Change in asset retirement obligations	**73.5**	–	**73.5**	–
Closure costs	**–**	–	**(13.4)**	–
Deferred income tax (expense) recovery (1)	**(27.0)**	13.6	**(115.1)**	77.3

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

Share-based compensation expense in 2019 includes $3.1 million related to 2.0 million options cancelled in the third quarter of 2019. Interest and financing expense was $30.0 million in the nine months ended September 30, 2019, an increase of $7.7 million compared to the same period in 2018, as a result of higher average debt balances in 2019 prior to the Midstream Transaction.

In the third quarter of 2019, the Company recorded a recovery of $73.5 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value ascribed to the property, plant and equipment of such properties as at September 30, 2019. The changes resulted from revisions to the estimated costs and timing of retirement.

The Company commenced its first area-based closure ("ABC") abandonment and reclamation project in the third quarter at Hawkeye. Economies of scale gained under the ABC approach have resulted in significantly lower costs than prior estimates. Paramount will continue to optimize its abandonment and reclamation activities based on the actual experience and knowledge gained from this and other projects and pursue additional opportunities to further reduce costs on an on-going basis. The Company's undiscounted estimated asset retirement obligation was revised from $1.79 billion as at December 31, 2018 to $1.65 billion as at September 30, 2019, and from $807.9 million to $749.1 million on a discounted basis.

In early 2019, Paramount made the decision to cease production operations at the Zama field in northern Alberta, which 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 will continue into 2020 to permanently suspend all facilities and over 2,000 kilometers of pipelines. The closure of Zama is expected to reduce the Company's total operating expenses by approximately $27 million per year. 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 has incurred $9.3 million in closure costs for the nine months ended September 30, 2019.

Deferred income tax expense for the nine months ended September 30, 2019 included $100.6 million related to a reduction in Alberta income tax rates.

PROPERTY, PLANT AND EQUIPMENT AND EXPLORATION EXPENDITURES

	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Base capital (1)				
Grande Prairie Region	**106.6**	70.2	**196.0**	216.4
Kaybob Region	**5.4**	33.6	**62.0**	172.5
Central Alberta and Other Region	**1.1**	16.8	**7.0**	33.5
Total base capital	**113.1**	120.6	**265.0**	422.4
Karr 6-18 Facility expansion	**–**	10.4	**45.5**	12.0
Corporate	**12.5**	2.4	**15.2**	8.3
Total capital additions	**125.6**	133.4	**325.7**	442.7
Land and property acquisitions	**1.9**	1.6	**6.2**	10.0
	127.5	135.0	**331.9**	452.7

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

Base capital expenditures totaled $113.1 million in the third quarter of 2019 compared to $120.6 million in the same period in 2018. Base capital expenditures were $265.0 million for the nine months ended September 30, 2019 compared to $422.4 million in the same period in 2018. Expenditures for the nine months ended September 30, 2019 mainly related to drilling and completion programs in the Grande Prairie and Kaybob Regions.

In the Grande Prairie Region, development activities for the nine months ended September 30, 2019 focused on completion operations at Wapiti for 12 (12.0 net) wells on the 5-3 pad, three of which were brought-on production through inline test facilities in late-September. Three additional wells were started-up on the 5-3 pad in October. The remaining wells are also scheduled to flowback on a rotational basis to recover completion fluids and prepare for the installation of permanent surface facilities. Grande Prairie Region activities also included completion operations at Karr for 5 (5.0 net) Montney wells on the 4-24 pad, which were brought-on production in late-September. The Company drilled 3 (3.0 net) new Montney wells on the Karr 1-19 pad, which are scheduled to be completed and brought on-stream late in the fourth quarter. Paramount incurred $45.5 million in 2019 related to the 6-18 Facility expansion, which was not included in the Company's $350 million base capital budget. The cash proceeds from the Midstream Transaction included the reimbursement of capital expenditures related to the 6-18 Facility expansion.

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

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

Capital expenditures for the 2019 capital programs at Wapiti and Central Alberta and Other Region are lower than originally budgeted. As a result of capital efficiencies realized to date in the 2019 program, the Company has accelerated drilling operations for 10 (10.0 net) Montney wells at Karr into the fourth quarter of 2019 that were originally scheduled for 2020, while maintaining its 2019 base capital budget at $350 million.

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	September 30, 2019	December 31, 2018
Cash and cash equivalents	**(11.1)**	(19.3)
Accounts receivable	**(91.9)**	(121.3)
Prepaid expenses and other	**(16.4)**	(9.6)
Accounts payable and accrued liabilities	**176.4**	231.2
Adjusted working capital deficit (1)	**57.0**	81.0
Paramount Facility	**720.9**	815.0
Net Debt (2)	**777.9**	896.0
Share capital	**2,184.8**	2,184.6
Retained earnings (accumulated deficit)	**(35.5)**	21.2
Reserves	**(78.5)**	44.7
Total Capital	**2,848.7**	3,146.5

(1) Adjusted working capital excludes risk management assets and liabilities, current accounts receivable amounts relating to subleases (September 30, 2019 - $2.1 million, December 31, 2018 – nil) and the current portion of asset retirement obligations and lease liabilities and other.

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

The change in net debt for the nine months ended September 30, 2019 is primarily due to proceeds from the Midstream Transaction and cash flows from operations, partially offset by capital expenditures. 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

The Company has a $1.5 billion financial covenant-based senior secured revolving bank credit 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. As at September 30, 2019, $8.2 million of undrawn letters of credit were outstanding under the Paramount Facility that reduce the amount available to be drawn.

Unsecured Letter of Credit Facility

During the third quarter, Paramount entered into a new $40 million unsecured demand revolving letter of credit facility (the "LC Facility") with a Canadian bank. Paramount's obligations under the LC Facility are supported by a performance security guarantee from Export Development Canada. As at September 30, 2019, $27.7 million of undrawn letters of credit were outstanding under the LC Facility.

Interest Rate Swaps

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

Contract type	Aggregate notional	Maturity date	Fixed contract rate	Reference	Fair value
Interest Rate Swap	$250 million	January 2023	2.3%	CDOR (1)	(4.6)
Interest Rate Swap	$250 million	January 2026	2.4%	CDOR (1)	(11.1)
					(15.7)

(1) Canadian Dollar Offered Rate.

In the first quarter of 2019, Paramount entered into interest rate swap contracts 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 September 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. To October 31, 2019, the Company has purchased and cancelled 2.6 million Common Shares under the 2019 NCIB at a total cost of $14.4 million. These purchases were mainly funded by the disposition of a portion of the Company's investment in MEG Energy Corp. 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 October 31, 2019, Paramount had 127,430,559 Common Shares outstanding (net of 859,659 Common Shares held in trust under the Company's restricted share unit plan) and 9,736,853 options to acquire Common Shares outstanding, of which 4,493,473 options are exercisable.

QUARTERLY INFORMATION

	2019			2018				2017
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Petroleum and natural gas sales	**199.8**	209.2	246.1	207.4	248.5	239.7	269.8	258.9
Net income (loss) (1)	**141.0**	(121.0)	(76.7)	(170.5)	(13.1)	(119.0)	(64.6)	(103.2)
Per share – basic & diluted ($/share)	***1.08***	*(0.93)*	*(0.59)*	*(1.31)*	*(0.10)*	*(0.90)*	*(0.48)*	*(0.76)*
Cash from operating activities	**48.6**	48.1	88.5	12.4	73.8	52.0	85.2	43.4
per share – basic & diluted ($/share)	***0.37***	*0.37*	*0.68*	*0.10*	*0.56*	*0.39*	*0.64*	*0.32*
Adjusted funds flow	**50.9**	54.2	100.5	45.5	58.2	62.6	97.6	110.1
Per share – basic & diluted ($/share)	***0.39***	*0.41*	*0.77*	*0.35*	*0.44*	*0.47*	*0.73*	*0.82*
Sales volumes								
Natural gas (MMcf/d)	**296.6**	309.7	308.0	315.2	303.8	334.1	351.1	359.9
Condensate and oil (Bbl/d)	**24,761**	23,312	23,679	24,898	22,868	23,815	25,391	26,285
Other NGLs (Bbl/d)	**6,851**	6,859	6,284	7,059	6,963	7,242	8,298	9,149
Total (Boe/d)	**81,046**	81,793	81,296	85,495	80,471	86,741	92,203	95,412
Average realized price								
Natural gas ($/Mcf)	**1.58**	1.76	3.37	2.73	1.93	1.71	2.59	2.11
Condensate and oil ($/Bbl)	**65.73**	71.02	63.26	45.54	79.83	77.25	70.10	66.65
Other NGLs ($/Bbl)	**9.78**	11.01	28.55	31.39	32.16	27.35	31.68	30.15
Total ($/Boe)	**26.80**	28.10	33.63	26.68	33.57	30.37	32.51	29.49

(1) Comparative amounts for the first, second and third quarters of 2018 and the fourth quarter of 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.

- Third quarter 2019 earnings include a $157.3 million gain on the sale of oil and gas assets, primarily related to the Midstream Transaction.
- 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.

OTHER INFORMATION

Contractual Obligations

Paramount had the following contractual obligations at September 30, 2019:

	Within 1 year	After one year but not more than three years	After three years but not more than five years	More than five years	Total
Paramount Facility (1)	–	–	720.9	–	**720.9**
Transportation and processing commitments (2)	222.5	499.3	449.9	1,410.4	**2,582.1**
Finance lease and other commitments (3)	13.5	23.2	3.6	0.1	**40.4**
	236.0	**522.5**	**1,174.4**	**1,410.5**	**3,343.4**

(1) Excluding interest.
(2) Certain of the transportation and processing commitments are secured by outstanding letters of credit totaling $10.3 million at September 30, 2019 (December 31, 2018 - $1.3 million).
(3) Undiscounted finance lease payments in respect of office and vehicle commitments have been reduced by sublease revenue amounts receivable.

Transportation and processing commitments mainly relate to long-term firm service arrangements for the processing and transportation of natural gas and liquids.

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 Liability's 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 lease liabilities and other	–	8.9	8.9
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 September 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 the fourth quarter of 2019;
- the scheduled completion of the Zama closure program and the anticipated reduction in future operating costs;
- planned exploration, development and production activities, including the anticipated timing of bringing new wells on production;
- the timing of completion of the 6-18 Facility expansion;
- budgeted capital expenditures and the maintenance of the 2019 base capital budget at $350 million;
- 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 "Base 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. Asset retirement settlements are excluded from the calculation of adjusted funds flow because such expenditures are not directly linked to the revenue generating activities of the Company. Paramount manages the timing of expenditures related to asset retirement obligation settlements in accordance with regulatory requirements and its overall approach to settling its asset retirement obligations and, as a result, amounts incurred may vary from period to period. Adjusted funds flow is not intended to represent cash from operating activities, net loss or any other GAAP measure and should not be construed as being an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS. 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**. **Base 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 the expansion of the 6-18 Facility prior to its sale, land and property acquisitions and corporate assets. The base 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	
Bbl	Barrels
Bbl/d	Barrels per day
NGLs	Natural gas liquids
Condensate	Pentane and heavier hydrocarbons

Oil Equivalent	
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day

Natural Gas	
Mcf	Thousands of cubic feet
MMcf	Millions of cubic feet
MMcf/d	Millions of cubic feet per day
GJ	Gigajoule
GJ/d	Gigajoules per day
MMbtu	Millions of British thermal units
AECO	AECO-C reference price
NYMEX	New York Mercantile Exchange

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 nine months ended September 30, 2019, the value ratio between crude oil and natural gas was approximately 53:1. 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.

Interim Condensed Consolidated Financial Statements (Unaudited)
For the three and nine months ended September 30, 2019

INTERIM CONDENSED CONSOLIDATED BALANCE SHEET

($ thousands)

As at	Note	September 30 2019	December 31 2018
		(Unaudited)	
ASSETS			
Current assets			
Cash and cash equivalents	13	11,091	19,295
Accounts receivable	6	93,981	121,330
Risk management - current	11	23,611	64,441
Prepaid expenses and other		16,411	9,641
		145,094	214,707
Risk management – long-term	11	4,354	–
Lease receivable	6	5,402	–
Exploration and evaluation	2	718,840	719,908
Property, plant and equipment, net	3	2,076,277	2,178,181
Investments in securities	4	155,781	231,732
Deferred income tax	10	665,313	773,575
		3,771,061	4,118,103
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		176,428	231,228
Risk management - current	11	3,187	–
Current portion of asset retirement obligations	6	16,350	32,000
Current portion of lease liabilities and other	6	13,944	–
		209,909	263,228
Long-term debt	5	720,923	815,000
Risk management – long-term	11	12,503	–
Asset retirement obligations and other	6	756,972	789,346
		1,700,307	1,867,574
Commitments and contingencies	14		
Shareholders' equity			
Share capital	7	2,184,770	2,184,608
Retained earnings (accumulated deficit)		(35,527)	21,189
Reserves	8	(78,489)	44,732
		2,070,754	2,250,529
		3,771,061	4,118,103

See the accompanying notes to these Interim Condensed Consolidated Financial Statements.

INTERIM CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)

($ thousands, except as noted)

	Note	Three months ended September 30		Nine months ended September 30	
		2019	2018	2019	2018
			(Restated – Note 1)		(Restated – Note 1)
Petroleum and natural gas sales		199,788	248,500	655,027	758,043
Royalties		(12,059)	(22,772)	(46,109)	(61,215)
Revenue	12	187,729	225,728	608,918	696,828
Gain (loss) on commodity contracts	11	17,050	(31,109)	(27,986)	(163,318)
		204,779	194,619	580,932	533,510
Expenses					
Operating expense		93,772	90,672	270,934	277,779
Transportation and NGLs processing		25,717	22,829	71,924	68,797
General and administrative		12,791	11,172	40,004	41,800
Share-based compensation	9	6,804	5,498	14,333	16,862
Depletion and depreciation	3	83,277	110,678	248,684	376,325
Exploration and evaluation	2	10,267	2,860	18,024	15,388
Gain on sale of oil and gas assets		(157,315)	(48,807)	(165,030)	(54,410)
Interest and financing	11	9,699	6,706	29,988	22,282
Accretion of asset retirement obligations	6	15,100	14,487	44,506	43,164
Change in asset retirement obligations	6	(73,480)	–	(73,480)	–
Closure costs	6	–	–	13,440	–
Gain on debt extinguishment		–	–	–	(3,126)
Transaction and reorganization costs		–	263	–	4,515
Other	4	8,648	(315)	8,767	(1,577)
		35,280	216,043	522,094	807,799
Other income (loss)		(1,553)	(5,292)	(408)	320
Income (loss) before tax		167,946	(26,716)	58,430	(273,969)
Income tax expense (recovery)					
Deferred	10	26,963	(13,631)	115,146	(77,271)
		26,963	(13,631)	115,146	(77,271)
Net income (loss)		140,983	(13,085)	(56,716)	(196,698)
Other comprehensive income (loss), net of tax	8				
Items that will be reclassified to net income (loss)					
Change in fair value of interest rate swaps, net of tax		383	–	(12,706)	–
Reclassification to net income (loss), net of tax		424	–	773	–
Items that will not be reclassified to net income (loss)					
Change in fair value of securities, net of tax	4	(112,522)	(11,719)	(123,843)	10,624
Comprehensive income (loss)		29,268	(24,804)	(192,492)	(186,074)
Net income (loss) per common share ($/share)	7				
Basic and diluted		1.08	(0.10)	(0.44)	(1.48)

See the accompanying notes to these Interim Condensed Consolidated Financial Statements.

INTERIM CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

(Unaudited)

($ thousands)

	Note	Three months ended September 30 2019	Three months ended September 30 2018	Nine months ended September 30 2019	Nine months ended September 30 2018
			(Restated – Note 1)		(Restated – Note 1)
Operating activities					
Net income (loss)		140,983	(13,085)	(56,716)	(196,698)
Add (deduct):					
Items not involving cash	13	(92,535)	68,666	254,680	403,116
Asset retirement obligations settled	6	(3,620)	(6,004)	(11,403)	(20,508)
Closure program expenditures	6	(4,909)	–	(9,298)	–
Gain on debt extinguishment	5	–	–	–	(3,126)
Change in non-cash working capital		8,656	24,229	7,914	28,237
Cash from operating activities		48,575	73,806	185,177	211,021
Financing activities					
Net draw (repayment) of revolving long-term debt	5	(188,771)	(63,842)	(94,077)	300,098
Lease liabilities – principal repayments	6	(1,879)	–	(5,555)	–
Redemption of 2019 Senior Notes	5	–	–	–	(303,624)
Common Shares issued, net of issue costs		–	41	110	719
Common Shares repurchased under NCIB	7	(212)	(24,556)	(212)	(65,767)
Common Shares purchased under restricted share unit plan	9	(4,516)	–	(4,516)	(9,219)
Cash used in financing activities		(195,378)	(88,357)	(104,250)	(77,793)
Investing activities					
Property, plant and equipment and exploration		(127,534)	(135,039)	(331,902)	(452,698)
Proceeds on sale of oil and gas assets		328,314	173,364	328,956	181,729
Investments		(49,308)	(3,716)	(55,338)	(3,716)
Change in non-cash working capital		(13,079)	(5,344)	(30,612)	52,432
Cash from (used in) investing activities		138,393	29,265	(88,896)	(222,253)
Net increase (decrease)		(8,410)	14,714	(7,969)	(89,025)
Foreign exchange on cash and cash equivalents		215	17	(235)	2,028
Cash and cash equivalents, beginning of period		19,286	21,601	19,295	123,329
Cash and cash equivalents, end of period		11,091	36,332	11,091	36,332
Supplemental cash flow information	13				

See the accompanying notes to these Interim Condensed Consolidated Financial Statements.

INTERIM CONDENSED CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

(Unaudited)

($ thousands, except as noted)

Nine months ended September 30	Note	2019		2018	
				(Restated – Note 1)	
		Shares (000's)		*Shares (000's)*	
Share Capital					
Balance, beginning of period		***130,326***	**2,184,608**	*134,713*	2,249,746
Issued		***13***	**158**	72	999
Common shares purchased and cancelled under NCIB	7	***(33)***	**(212)**	(4,137)	(65,767)
Change in vested and unvested Common Shares for restricted share unit plan	9	***(286)***	**216**	(231)	(748)
Balance, end of period		***130,020***	**2,184,770**	*130,417*	2,184,230
Retained Earnings (Accumulated Deficit)					
Balance, beginning of period			**21,189**		389,989
Net loss			**(56,716)**		(196,698)
Balance, end of period			**(35,527)**		193,291
Reserves	8				
Balance, beginning of period			**44,732**		26,522
Other comprehensive income (loss)			**(135,776)**		10,624
Contributed surplus			**12,555**		12,543
Reclassification of accumulated losses on securities sold			**–**		1,637
Balance, end of period			**(78,489)**		51,326
Total Shareholders' Equity			**2,070,754**		2,428,847

See the accompanying notes to these Interim Condensed Consolidated Financial Statements.

1. Basis of Presentation

Paramount Resources Ltd. ("Paramount" or the "Company") 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.

Paramount is the ultimate parent company of a consolidated group of companies and is incorporated and domiciled in Canada. The address of its registered office is 2800, 421 – 7th Avenue S.W., Calgary, Alberta, Canada, T2P 4K9. The consolidated group includes wholly-owned subsidiaries Fox Drilling Limited Partnership, Cavalier Energy and MGM Energy. The financial statements of Paramount's subsidiaries and partnerships are prepared for the same reporting periods as the parent in accordance with the Company's accounting policies. All intercompany balances and transactions have been eliminated.

These unaudited Interim Condensed Consolidated Financial Statements of the Company, as at and for the three and nine months ended September 30, 2019 (the "Interim Financial Statements"), were authorized for issuance by the Audit Committee of Paramount's Board of Directors on November 6, 2019.

These Interim Financial Statements have been prepared in accordance with *IAS 34 – Interim Financial Reporting* on a basis consistent with the accounting, estimation and valuation policies described in the Company's audited Consolidated Financial Statements as at and for the year ended December 31, 2018 (the "Annual Financial Statements"), except for changes in Paramount's accounting policies as a result of the adoption of *IFRS 16 – Leases* ("IFRS 16"), which are described below.

These Interim Financial Statements are stated in thousands of Canadian dollars, unless otherwise noted, and have been prepared on a historical cost basis, except for certain financial instruments which are stated at fair value. Certain information and disclosures normally required to be included in the notes to the Annual Financial Statements prepared in accordance with International Financial Reporting Standards have been condensed or omitted. These Interim Financial Statements should be read in conjunction with the Annual Financial Statements.

As described in Notes 1 and 22 of the Annual Financial Statements, effective December 31, 2018, Paramount voluntarily changed its accounting policy with respect to asset retirement obligations to utilize a credit-adjusted risk-free discount rate to determine the discounted amount of the liability presented at each balance sheet date. The Company had previously utilized a risk-free discount rate to determine the discounted amount of the liability. The change in accounting policy was applied retrospectively, including the restatement of certain comparative amounts in these Interim Financial Statements.

The Company applies hedge accounting to certain hedging instruments when such instruments are designated at inception as qualifying hedging relationships. Hedge effectiveness is evaluated by assessing the critical terms of the hedging relationship at inception, at the end of each reporting date and upon a significant change in the circumstances affecting hedge effectiveness. The effective portion of the change in the unrealized fair value of the hedging instrument is recognized in other comprehensive income ("OCI"). Accumulated gains or losses are reclassified from OCI to earnings as amounts are settled throughout the term of the arrangement. Any portion of the change in the fair value of the hedging instrument related to hedge ineffectiveness is recognized in earnings.

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. Paramount has established its accounting policy in accordance with IFRS 16 as follows:

The determination of whether an arrangement is, or contains a lease, is based on the substance of the arrangement at the inception date. An arrangement is a lease when the terms of the agreement relate to the use of a specific asset and the lessee has the right to control the use of the specified asset.

Lessee

On the date a leased asset is first available for use by the Company, a right-of-use ("ROU") asset and a corresponding lease liability are recognized. The ROU asset is depreciated over the lease term and the lease liability is reduced as payments are made under the agreement. Each lease payment is allocated between a principal repayment and an interest component.

Assets and liabilities recognized in respect of leases are recorded on a discounted basis. Lease liabilities consist of the net present value of the aggregate fixed lease payments, as defined by IFRS 16. Where the rate implicit in a lease is not readily determinable, lease payments are discounted using the Company's incremental borrowing rate. ROU assets are recognized at the amount corresponding to the amount of the initial lease liability. Lease payments in respect of short-term leases with terms of less than twelve months, or in respect of leases for which the underlying asset is of low value, are expensed as incurred.

Lessor

As a lessor, contractual arrangements which transfer substantially all of the risks and benefits of ownership of an asset to the lessee are accounted for as finance leases. Under a finance lease, the present value of the minimum lease payments receivable from the lessee are recorded as an account receivable. Lease payments received are applied against the receivable balance, with an interest component recognized as interest revenue.

If substantially all of the risks and benefits of ownership of an asset are not transferred to the lessee, the lease is classified as an operating lease and lease payments received are recognized as income over the term of the agreement.

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* 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 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 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	121,330	1,690	123,020
Lease receivable	–	6,933	6,933
Property, plant, and equipment, net	2,178,181	9,531	2,187,712
Accounts payable and accrued liabilities	231,228	(7,541)	223,687
Current portion of lease liabilities and other	–	8,941	8,941
Asset retirement obligations and other	789,346	16,754	806,100

Refer to Note 6 for further details regarding the Company's lease and sublease arrangements.

2. Exploration and Evaluation

	Nine months ended September 30, 2019	Twelve months ended December 31, 2018
Balance, beginning of period	719,908	785,764
Additions	3,126	8,300
Acquisitions	7,131	–
Change in asset retirement provision	99	–
Transfers to property, plant and equipment	(951)	(34,388)
Expired lease costs	(10,473)	(14,781)
Dispositions	–	(24,987)
Balance, end of period	718,840	719,908

Exploration and Evaluation Expense

	Three months ended September 30		Nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Geological and geophysical	2,436	2,322	7,551	10,599
Expired lease costs	7,831	538	10,473	4,789
	10,267	2,860	18,024	15,388

3. Property, Plant and Equipment

Nine months ended September 30, 2019	Petroleum and natural gas assets	Drilling rigs	Right-of-use assets	Other	Total
Cost					
Balance, December 31, 2018	4,041,098	159,817	–	46,574	4,247,489
Right-of-use assets [(1)]	–	–	13,965	(4,434)	9,531
Balance, January 1, 2019	4,041,098	159,817	13,965	42,140	4,257,020
Additions	327,969	971	1,851	4,331	335,122
Transfers from exploration and evaluation	951	–	–	–	951
Dispositions	(208,076)	–	–	(300)	(208,376)
Change in asset retirement provision	(17,649)	–	–	–	(17,649)
Cost, end of period	**4,144,293**	**160,788**	**15,816**	**46,171**	**4,367,068**
Accumulated depletion, depreciation and impairment					
Balance, December 31, 2018	(1,961,290)	(78,865)	–	(29,153)	(2,069,308)
Right-of-use assets [(1)]	–	–	(2,158)	2,158	–
Balance, January 1, 2019	(1,961,290)	(78,865)	(2,158)	(26,995)	(2,069,308)
Depletion and depreciation	(235,045)	(8,054)	(2,088)	(4,600)	(249,787)
Dispositions	28,004	–	–	300	28,304
Accumulated depletion, depreciation and impairment, end of period	**(2,168,331)**	**(86,919)**	**(4,246)**	**(31,295)**	**(2,290,791)**
Net book value, December 31, 2018	2,079,808	80,952	–	17,421	2,178,181
Net book value, September 30, 2019	**1,975,962**	**73,869**	**11,570**	**14,876**	**2,076,277**

(1) Recognized on adoption of IFRS 16, see notes 1 and 6.

In the third quarter of 2019, Paramount closed the sale of its Karr 6-18 natural gas facility and related midstream assets located in the Grande Prairie cash generating unit for net cash proceeds of $327.6 million. 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 completed in 2020. A gain of $153.7 million was recognized on the sale.

4. Investments in Securities

As at	September 30, 2019	December 31, 2018
Level one fair value hierarchy securities	86,988	36,017
Level three fair value hierarchy securities	68,793	195,715
	155,781	231,732

Investments that are categorized as level one fair value hierarchy securities are carried at their period-end value based on the trading prices of the security quoted in an active market. Estimates of fair value for investments that are categorized as level three fair value hierarchy securities are based on valuation techniques that incorporate unobservable inputs. The valuation techniques utilize market-based metrics of comparable companies and transactions, indications of value based on equity transactions of the entities and other indicators of value. Fair value estimates of level three fair value hierarchy securities are updated at each balance sheet date to confirm whether the carrying value of the investment continues to fall within a range of possible fair values indicated by such techniques. At September 30, 2019, the Company recorded a $118.1 million charge to other comprehensive income as a result of updates to fair value range estimates for level three fair value hierarchy securities. Other expense for the nine months ended

September 30, 2019 includes $8.8 million related to the estimated change in fair value of Strath Resources Ltd. warrants.

5. Long-Term Debt

As at	September 30, 2019	December 31, 2018
Paramount Facility	720,923	815,000

Paramount Facility

The Company has 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. As at September 30, 2019, $8.2 million of undrawn letters of credit were outstanding under the Paramount Facility that reduce the amount available to be drawn.

Unsecured Letter of Credit Facility

During the third quarter, Paramount entered into a new $40 million unsecured demand revolving letter of credit facility (the "LC Facility") with a Canadian bank. Paramount's obligations under the LC Facility are supported by a performance security guarantee from Export Development Canada. As at September 30, 2019, $27.7 million of undrawn letters of credit were outstanding under the LC Facility.

2019 Senior Notes

In April 2018, Paramount redeemed all $300 million principal amount of the Company's outstanding 7¼ percent senior unsecured notes due 2019 (the "2019 Senior Notes") and was discharged and released from all obligations and covenants related to the notes. The redemption was funded with drawings on the Paramount Facility. The Company recorded a net gain of $3.1 million in connection with the redemption of the 2019 Senior Notes. The 2019 Senior Notes were issued by Trilogy Energy Corp. ("Trilogy") in 2012 and became Paramount's obligation through the merger with Trilogy in 2017.

6. Asset Retirement Obligations and Other

As at September 30, 2019	Current	Long-term	Total
Lease liabilities (see note 1)	9,802	24,212	34,014
Closure costs	4,142	–	4,142
Lease liabilities and other	13,944	24,212	38,156
Asset retirement obligations	16,350	732,760	749,110
Asset retirement obligations and other	**30,294**	**756,972**	**787,266**

As at December 31, 2018	Current	Long-term	Total
Asset retirement obligations	32,000	775,921	807,921
Lease provision (see note 1)	–	13,425	13,425
	32,000	789,346	821,346

Asset Retirement Obligations

	Nine months ended September 30, 2019	Twelve months ended December 31, 2018
Asset retirement obligations, beginning of period	807,921	837,463
Additions	7,908	6,020
Acquisitions	3,333	–
Revisions to estimated retirement costs	(91,554)	(4,038)
Revisions due to change in discount rate	–	(50,910)
Obligations settled	(11,403)	(29,390)
Dispositions	(11,601)	(8,876)
Accretion expense	44,506	57,652
Asset retirement obligations, end of period	749,110	807,921

As at September 30, 2019, estimated undiscounted asset retirement obligations were $1,645.1 million (December 31, 2018 – $1,785.1 million). Asset retirement obligations have been determined using a weighted average credit-adjusted risk-free discount rate of 7.5 percent (December 31, 2018 – 7.5 percent) and an inflation rate of 2.0 percent (December 31, 2018 – 2.0 percent).

In the third quarter of 2019, the Company recorded a recovery of $73.5 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value ascribed to the property, plant and equipment of such properties as at September 30, 2019. The changes resulted from revisions to the estimated costs and timing of retirement.

Lease Liabilities

Paramount has lease liabilities in respect of office space and vehicles, which have been recognized at the discounted value of the remaining fixed lease payments. A weighted average incremental borrowing rate of approximately nine percent was used to determine the discounted amount of the liabilities. For the nine months ended September 30, 2019, total cash payments made in respect of these lease liabilities, net of sublease arrangements, were $6.7 million, of which $1.2 million was recognized as interest and financing expense.

For the nine months ended September 30, 2019, operating expenses related to arrangements containing short-term and low value leases which have not been included in the lease liability were approximately $0.3 million.

As at September 30, 2019, $7.4 million is due to the Company in respect of sublease arrangements for Paramount's office space, of which $2.0 million was classified as current and $5.4 million was classified as non-current. For the nine months ended September 30, 2019, $1.6 million was received in respect of office sublease arrangements, of which $0.4 million was recognized as interest revenue.

The minimum cash lease payments payable by the Company under these lease arrangements and receivable amounts due to the Company in respect of sublease arrangements are as follows:

	Lease Payments	Sublease Receivables
October 2019 to December 2019	2,791	541
2020	11,232	2,378
2021	10,840	2,424
2022	9,926	2,316
2023	1,932	518
	36,721	8,177

Closure costs

In the first quarter of 2019, the Company made the decision to cease its production operations at the Zama field in northern Alberta. The Zama closure program commenced in the first quarter of 2019 and is expected to span approximately twelve months. The Company recognized a provision of $13.4 million as at March 31, 2019 in respect of the expected costs of the program, of which $9.3 million has been incurred to September 30, 2019.

7. Share Capital

As at September 30, 2019, 130,019,659 (December 31, 2018 – 130,324,943) class A common shares of the Company ("Common Shares") were outstanding, net of 859,659 (December 31, 2018 – 574,045) Common Shares held in trust under the restricted share unit plan.

In January 2019, Paramount implemented a normal course issuer bid program (the "2019 NCIB") under which the Company may purchase up to 7,110,667 Common Shares for cancellation. 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. To October 31, 2019, the Company has purchased and cancelled 2,622,200 Common Shares under the 2019 NCIB at a total cost of $14.4 million.

Paramount previously implemented a normal course issuer bid in December 2017 (the "2018 NCIB"). The Company purchased and cancelled 4,239,359 Common Shares at a total cost of $66.4 million under the 2018 NCIB, which expired on December 21, 2018.

Weighted Average Common Shares

Three months ended September 30	2019		2018	
	Wtd. Avg Shares (000's)	Net income	*Wtd. Avg Shares (000's)*	Net loss
Net income (loss) – basic	*130,064*	140,983	*131,341*	(13,085)
Dilutive effect of Paramount Options	–	–	–	–
Net income (loss) – diluted	*130,064*	140,983	*131,341*	(13,085)

Nine months ended September 30	2019		2018	
	Wtd. Avg Shares (000's)	Net loss	*Wtd. Avg Shares (000's)*	Net loss
Net loss – basic	*130,332*	(56,716)	*132,601*	(196,698)
Dilutive effect of Paramount Options	–	–	–	–
Net loss – diluted	*130,332*	(56,716)	*132,601*	(196,698)

Outstanding stock options that can be exchanged for the Company's Common Shares are potentially dilutive and are included in Paramount's diluted per share calculations when they are dilutive to net income per share. There were 9.7 million options to acquire Common Shares outstanding at September 30, 2019 (September 30, 2018 – 9.2 million), all of which (September 30, 2018 – 9.2 million) were anti-dilutive.

8. Reserves

Nine months ended September 30, 2019	Unrealized losses on securities	Unrealized losses on interest rate swaps	Contributed surplus	Total Reserves
Balance, beginning of period	(99,052)	–	143,784	44,732
Other comprehensive loss, before tax	(126,970)	(15,691)	–	(142,661)
Deferred tax	3,127	3,758	–	6,885
Share-based compensation	–	–	12,603	12,603
Options exercised	–	–	(48)	(48)
Balance, end of period	**(222,895)**	**(11,933)**	**156,339**	**(78,489)**

9. Share-Based Compensation

Options to Acquire Common Shares of Paramount ("Paramount Options")

	Nine months ended September 30, 2019		Twelve months ended December 31, 2018	
	Number	Weighted average exercise price ($/share)	*Number*	Weighted average exercise price ($/share)
Balance, beginning of period	*12,465,163*	15.67	*10,028,920*	19.12
Granted	*280,000*	6.79	*3,726,500*	8.18
Exercised (1)	*(13,430)*	8.17	*(79,536)*	9.80
Cancelled or forfeited	*(3,015,514)*	19.19	*(1,168,710)*	21.42
Expired	*–*	–	*(42,011)*	26.73
Balance, end of period	***9,716,219***	**14.33**	*12,465,163*	15.67
Options exercisable, end of period	***2,571,389***	**16.93**	*3,620,293*	18.09

(1) For Paramount Options exercised during the nine months ended September 30, 2019, the weighted average market price of Paramount's Common Shares on the dates exercised was $9.14 per share (twelve months ended December 31, 2018 – $16.70 per share).

Share-based compensation expense for the nine months ended September 30, 2019 includes $3.1 million related to 1,985,952 options cancelled in September 2019.

Restricted Share Unit Plan – Shares Held in Trust

	Nine months ended September 30, 2019		Twelve months ended December 31, 2018	
	Shares (000's)		*Shares (000's)*	
Balance, beginning of period	*574*	2,209	*346*	2,366
Shares purchased	*713*	4,516	*548*	9,219
Change in vested and unvested shares	*(427)*	(4,732)	*(320)*	(9,376)
Balance, end of period	***860***	**1,993**	*574*	2,209

10. Income Tax

The following table reconciles income taxes calculated at the Canadian statutory rate to Paramount's recorded income tax expense (recovery):

	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Income (loss) before tax	167,946	(26,716)	58,430	(273,969)
Effective Canadian statutory income tax rate	26.5%	27.0%	26.5%	27.0%
Expected income tax expense (recovery)	44,506	(7,213)	15,484	(73,972)
Effect on income taxes of:				
Change in statutory and other rates	(5,324)	–	100,596	–
Gain on sale of oil and gas assets	(17,129)	–	(17,129)	–
Change in value of investments	2,337	–	2,337	–
Gain on redemption of 2019 Senior Notes	–	–	–	(1,823)
Change in unrecognized deferred income tax asset	314	271	765	658
Share-based compensation	1,734	1,240	3,340	3,462
Non-deductible items and other	525	(7,929)	9,753	(5,596)
Income tax expense (recovery)	26,963	(13,631)	115,146	(77,271)

11. Financial Instruments and Risk Management

As at	September 30, 2019	December 31, 2018
Financial commodity contracts – current	23,611	64,441
Financial commodity contracts – long-term	4,354	–
Risk management asset	27,965	64,441

As at	September 30, 2019	December 31, 2018
Interest rate swaps – current	(3,187)	–
Interest rate swaps – long-term	(12,503)	–
Risk management liability	(15,690)	–

The Company is exposed to market risks from changes in commodity prices, interest rates, foreign currency rates, credit risk and liquidity risk. From time-to-time, Paramount enters into derivative financial instruments to manage these risks.

The fair values of risk management financial instruments are estimated using a market approach incorporating level two fair value hierarchy inputs, including forward market curves and price quotes for similar instruments, provided by financial institutions.

Changes in the fair value of risk management assets and liabilities are as follows:

	Nine months ended September 30, 2019	Twelve months ended December 31, 2018
Fair value, beginning of period	64,441	(19,060)
Changes in fair value – financial commodity contracts	(27,986)	7,026
Changes in fair value – interest rate swaps	(14,673)	–
Settlements paid (received)	(9,507)	76,475
Fair value, end of period	12,275	64,441

Financial Commodity Contracts

The Company had the following financial commodity contracts in place as at September 30, 2019:

Instruments	Aggregate notional	Average fixed price	Fair value	Remaining term
Oil – NYMEX WTI Swaps (Sale)	16,000 Bbl/d	CDN$78.05/Bbl	9,960	October 2019 – December 2019
Oil – NYMEX WTI Calls (Sale)	2,000 Bbl/d	CDN$82.00/Bbl (1)	489	October 2019 – December 2019
Oil – NYMEX WTI Swaps (Sale)	4,000 Bbl/d	CDN$80.11/Bbl	17,414	January 2020 – December 2020
Other			102	
			27,965	

(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.

Interest Rate Swaps

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

Contract Type	Aggregate notional	Maturity Date	Fixed Contract Rate	Reference	Fair value
Interest Rate Swaps	$250 million	January 2023	2.3%	CDOR (1)	(4,581)
Interest Rate Swaps	$250 million	January 2026	2.4%	CDOR (1)	(11,109)
					(15,690)

(1) Canadian Dollar Offered Rate.

In the first quarter of 2019, Paramount entered into interest rate swap contracts 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 September 30, 2019, there were no changes to the critical terms of the hedging relationship and no hedge ineffectiveness was identified.

12. Revenue By Product

	Three months ended September 30		Nine months ended September 30	
	2019	2018	2019	2018
Natural gas	43,094	53,854	185,933	187,853
Condensate and oil	149,741	167,956	435,211	495,572
Other natural gas liquids	6,164	20,603	29,186	62,282
Royalty and sulphur income	789	6,087	4,697	12,336
Royalties expense	(12,059)	(22,772)	(46,109)	(61,215)
	187,729	225,728	608,918	696,828

13. Consolidated Statement of Cash Flows - Selected Information

Items Not Involving Cash

	Three months ended September 30		Nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Commodity contracts	**(11,397)**	1,047	**36,476**	96,170
Share-based compensation	**6,804**	5,498	**14,333**	16,862
Depletion and depreciation (1)	**83,277**	110,678	**248,684**	376,325
Exploration and evaluation	**7,831**	538	**10,473**	4,789
Gain on sale of oil and gas assets (1)	**(157,315)**	(48,807)	**(165,030)**	(54,410)
Accretion of asset retirement obligations (1)	**15,100**	14,487	**44,506**	43,164
Closure costs	**–**	–	**13,440**	–
Change in asset retirement obligations	**(73,480)**	–	**(73,480)**	–
Deferred income tax (1)	**26,963**	(13,631)	**115,146**	(77,271)
Other	**9,682**	(1,144)	**10,132**	(2,513)
	(92,535)	68,666	**254,680**	403,116

(1) 2018 amounts restated, refer to Note 1.

Supplemental Cash Flow Information

	Three months ended September 30		Nine months ended September 30	
	2019	**2018**	**2019**	**2018**
Interest paid	**8,501**	6,501	**27,783**	21,677

Components of Cash and Cash Equivalents

As at	September 30, 2019	December 31, 2018
Cash	**11,091**	19,295
Cash equivalents	**–**	–
	11,091	19,295

14. Commitments & Contingencies

Paramount had the following commitments as at September 30, 2019:

	Within one year	After one year but not more than five years	More than five years
Petroleum and natural gas transportation and processing commitments (1)	222,452	949,160	1,410,410
Other commitments	4,638	7,140	92
	227,090	**956,300**	**1,410,502**

(1) Certain of the transportation and processing commitments are secured by outstanding letters of credit totaling $10.3 million at September 30, 2019 (December 31, 2018 – $1.3 million.)

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.

CORPORATE INFORMATION

EXECUTIVE OFFICERS

J. H. T. Riddell
Chairman and President and Chief Executive Officer

B. K. Lee
Executive Vice President, Finance and Chief Financial Officer

E. M. Shier
General Counsel, Corporate Secretary and Vice President, Land

D. B. Reid
Executive Vice President, Operations

R. R. Sousa
Executive Vice President, Corporate Development and Planning

J. B. Williams
Executive Vice President, Kaybob Region

P. R. Kinvig
Vice President Finance, Capital Markets

DIRECTORS

J. H. T. Riddell (2)
Chairman and President and Chief Executive Officer
Paramount Resources Ltd.
Calgary, Alberta

J. G. M. Bell (1) (3) (4)
President and Chief Executive Officer
Founders Advantage Capital Corp.
Calgary, Alberta

W. A. Gobert (3) (4) (5)
Independent Businessman
Calgary, Alberta

J. C. Gorman (1) (4) (5)
Independent Businessman
Calgary, Alberta

D. Jungé C.F.A. (2) (4)
Chairman of the Board
Pitcairn Trust Company
Bryn Athyn, Pennsylvania

R. M. MacDonald (1) (4)
Independent Businessman
Oakville, Ontario

R. K. MacLeod (2) (4) (5)
Independent Businessman
Calgary, Alberta

S. L. Riddell Rose
President and
Chief Executive Officer
Perpetual Energy Inc.
Calgary, Alberta

J. B. Roy (1) (3) (4)
Independent Businessman
Calgary, Alberta

(1) Member of Audit Committee
(2) Member of Environmental, Health and Safety Committee
(3) Member of Compensation Committee
(4) Member of Corporate Governance Committee
(5) Member of Reserves Committee

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Canadian Imperial Bank of Commerce

National Bank of Canada

ATB Financial

The Toronto-Dominion Bank

Export Development Canada

RESERVES EVALUATORS

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Calgary, Alberta

AUDITORS

Ernst & Young LLP
Calgary, Alberta

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
("POU")