Third Quarter 2021 Results

Paramount Resources Ltd. Announces Third Quarter 2021 Results, Updated 2021 Guidance, 2022 Capital Budget and Guidance and Increased Dividend

Calgary, Alberta – November 4, 2021

Paramount Resources Ltd. ("Paramount" or the "Company") (TSX:POU) is pleased to announce strong third quarter 2021 financial and operating results, upwardly revised 2021 guidance and its approved 2022 capital expenditure budget that is forecast to generate approximately $455 million in free cash flow in 2022 on production of between 90,000 Boe/d and 94,000 Boe/d (46 percent liquids).(1)(2) The Company is also pleased to announce a tripling of its regular monthly dividend from $0.02 to $0.06 per class A common share ("Common Share") effective November 2021.

Q3 2021 HIGHLIGHTS

- Sales volumes averaged 82,150 Boe/d (45 percent liquids) in the third quarter of 2021.
    - Karr sales volumes averaged 39,878 Boe/d (52 percent liquids), in line with expectations.
    - Wapiti sales volumes averaged 14,651 Boe/d (62 percent liquids), approximately 4,000 Boe/d higher than in the second quarter despite a 10-day scheduled plant outage. This 38 percent increase in production was mainly the result of new production from the seven well 6-4 pad that was brought onstream in July.
    - Early production rates at the two-well Willesden Green 4-7 pad brought onstream in July are extremely encouraging. Despite being restricted by facility constraints, average gross peak 30-day production per well was 1,498 Boe/d (3.3 MMcf/d of shale gas and 948 Bbl/d of NGLs) with an average CGR of 287 Bbl/MMcf.(3)
- Cash from operating activities was $97.0 million in the third quarter. Adjusted funds flow was $148.4 million or $1.12 per basic share.(4) Free cash flow was $72.6 million.

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(1) "Free cash flow" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section. See the "2022 Budget and Guidance" section for a description of the assumptions upon which the free cash flow forecast is based.

(2) In this press release, "liquids" refers to NGLs (including condensate) and oil combined, "natural gas" refers to conventional natural gas and shale gas combined, "condensate and oil" refers to condensate, light and medium crude oil and tight oil combined and "other NGLs" refers to ethane, propane and butane combined. See the Product Type Information section for a complete breakdown of sales volumes for applicable periods by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil. See also "Oil and Gas Measures and Definitions" in the Advisories section.

(3) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 4% and liquids sales volumes are lower by approximately 9% 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. CGR means condensate to gas ratio and is calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See "Oil and Gas Measures and Definitions" in the Advisories section.

(4) "Adjusted funds flow" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.

- Third quarter capital spending totaled $68.9 million and was focused on drilling and completion activities at Karr, Wapiti and the Willesden Green Duvernay.
  - Preliminary all-in lease construction, drilling, completion, equip and tie-in (collectively "DCET") costs at the five-well Karr 5-16 East pad that was brought on production in late October 2021 averaged $6.3 million per well, approximately 15 percent lower than average DCET costs at the 5-16 West pad that was brought onstream in the fourth quarter of 2020.
  - The Company continues to achieve lower costs in its Karr and Wapiti drilling and completion programs despite emerging industry cost inflation by utilizing its wholly-owned Fox Drilling rigs and crews and securing fixed rates with certain service providers.
- Per unit operating costs continue to decrease and averaged $11.02/Boe in the third quarter of 2021, down from $11.23/Boe in the second quarter and $11.63/Boe in the first quarter. Karr operating costs averaged $9.03/Boe in the third quarter of 2021.
- Abandonment and reclamation expenditures in the third quarter totaled $6.9 million, net of $0.9 million in funding under the Alberta Site Rehabilitation Program ("ASRP").
- The Company implemented a regular monthly dividend in July and repurchased 197,500 Common Shares under its normal course issuer bid ("NCIB") in the third quarter at an average price of $13.66 per share.
- Paramount closed the sale of its non-operated Birch asset for proceeds of approximately $85 million.
- The carrying value of the Company's investments in securities at September 30, 2021 was approximately $300 million, approximately $75 million higher on a quarter over quarter basis.

UPDATED 2021 GUIDANCE

- Paramount expects fourth quarter sales volumes to range between 85,000 Boe/d and 86,500 Boe/d (45 percent liquids). As a result, full year 2021 sales volumes are expected to average approximately 82,000 Boe/d (44 percent liquids), achieving the high end of the previous guidance range of 80,000 Boe/d to 82,000 Boe/d, 1,000 Boe/d higher than the mid-point.
- The Company has added approximately $15 million of capital expenditures in the second half of 2021, which include additional activities at Wapiti to accelerate the achievement of targeted plateau production of 30,000 Boe/d into 2023 and further debottlenecking initiatives at Karr. Full year 2021 capital spending is now expected to be between $285 and $295 million.
- Paramount is forecasting 2021 free cash flow of approximately $215 million, an increase of $30 million from previous guidance. The increase reflects year-to-date actual results, updated sales volumes guidance and revised commodity price and other assumptions for the fourth quarter of 2021.(1)
- Year-end net debt to adjusted funds flow is forecast to be approximately 0.8x, below the Company's previously targeted range of 1.0x to 2.0x.(2)

(1) The stated forecast is based on the following assumptions for 2021: (i) the midpoint of forecast capital spending and production, (ii) $25 million in net abandonment and reclamation costs, (iii) realized pricing of $47.55/Boe (US$67.63/Bbl WTI, US$3.94/MMBtu NYMEX, $3.59/GJ AECO), (iv) royalties of $4.60/Boe, (v) operating costs of $11.15/Boe and (vi) transportation and processing costs of $4.00/Boe.

(2) "Net debt" and "Net debt to adjusted funds flow" are Non-GAAP financial measures. See "Non-GAAP Financial Measures" in the Advisories section. The forecast of year end net debt to adjusted funds flow assumes the payment of a regular monthly dividend of $0.06 per Common Share commencing in November 2021 and the conversion of the Company's $35 million of convertible debentures into Common Shares in the fourth quarter of 2021.

2022 BUDGET AND GUIDANCE

The Company's 2022 capital budget is expected to range between $500 million and $540 million, excluding land acquisitions and abandonment and reclamation activities, an increase of $165 million at midpoint from preliminary guidance. The budget includes the acceleration of approximately $70 million in activities at Wapiti, $60 million to advance a number of high return opportunities in the Kaybob and Central Alberta & Other Regions and additional growth capital that will primarily benefit 2023 production. Paramount remains committed to prudently managing its capital resources and has the flexibility to adjust its capital expenditure plans depending on commodity prices and other factors.

Annual average sales volumes in 2022 are now expected to be between 90,000 Boe/d and 94,000 Boe/d (46 percent liquids), an increase of 6,000 Boe/d from previous preliminary guidance.

- First half 2022 sales volumes are expected to average between 81,000 Boe/d and 85,000 Boe/d (44 percent liquids) after accounting for a planned 16-day full field outage at Karr for turnaround activities at third-party midstream facilities.
- Second half 2022 sales volumes are expected to average between 99,000 Boe/d and 103,000 Boe/d (47 percent liquids) as numerous wells are brought onstream related to capital activities initiated earlier in 2022.

Paramount is forecasting approximately $455 million of free cash flow in 2022, $135 million higher than the Company's prior preliminary guidance.(1)

The 2022 capital budget is broken down as follows at midpoint:

- $290 million of sustaining capital and maintenance activities;
- $160 million of growth capital associated with production benefits in 2022; and
- $70 million of growth capital associated with production benefits largely in 2023.

The breakdown by region is as follows at midpoint:

- Grande Prairie − $365 million;
- Kaybob − $130 million;
- Central Alberta & Other − $10 million; and
- Corporate − $15 million.

The Company has budgeted approximately $41 million for abandonment and reclamation activities in 2022. Approximately $8 million is to be funded directly through the ASRP, resulting in approximately $33 million net to Paramount. The majority of these funds will be directed to the Zama area.

(1) The stated free cash flow forecast is based on the following assumptions for 2022: (i) the midpoint of forecast capital spending and production, (ii) $33 million in net abandonment and reclamation costs, (iii) realized pricing of $53.70/Boe (US$74.44/Bbl WTI, US$4.35/MMBtu NYMEX, $3.95/GJ AECO), (iv) royalties of $6.65/Boe, (v) operating costs of $11.00/Boe and (vi) transportation and processing costs of $3.85/Boe.

FREE CASH FLOW PRIORITIES

Paramount's free cash flow priorities continue to be (i) the achievement of targeted leverage levels, (ii) shareholder returns and (iii) incremental growth.

- With strong 2021 performance and commodity prices, the Company expects year-end 2021 net debt to adjusted funds flow will be approximately 0.8x, below the previously targeted range of 1.0x to 2.0x.
- The Company is reducing its targeted long-term leverage level to approximately $300 million in net debt. This target is expected to be achieved in the third quarter of 2022, implying a net debt to trailing 12-month adjusted funds flow ratio of less than 0.5x at the end of that quarter.(1)
- Paramount implemented a regular monthly dividend of $0.02 per share in July 2021 and is tripling its monthly dividend beginning in November 2021 to $0.06 per share, implying a 10 percent payout ratio for 2022 and a 3.4 percent current dividend yield.(2)
- Remaining 2022 free cash flow will be available to:
    - further augment shareholder returns through increases in the regular monthly dividend, special dividends or opportunistic repurchases of Common Shares under the NCIB; and
    - reinvest in incremental organic growth or strategic acquisitions.

Paramount has hedged approximately 23 percent of its 2022 midpoint forecast production to provide greater free cash flow certainty. With these hedges, the Company's 2022 capital program, targeted net debt reduction and $0.06 per share regular monthly dividend would remain fully funded down to an annual average WTI price in 2022 of approximately US$52.50/Bbl with no changes to the Company's natural gas pricing assumptions.

PRELIMINARY 2023 GUIDANCE

Based on preliminary planning and current market conditions, Paramount anticipates 2023 capital spending, excluding land acquisitions and abandonment and reclamation activities, to range between $475 million and $525 million, broken down as follows at midpoint:

- $330 million of sustaining capital and maintenance activities; and
- $170 million of growth capital.

The breakdown by region is as follows at midpoint:

- Grande Prairie − $295 million;
- Kaybob − $170 million;
- Central Alberta & Other − $25 million; and
- Corporate − $10 million.

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(1) The forecasted timing of achieving the targeted net debt level and net debt to adjusted funds flow assumes the payment of a regular monthly dividend of $0.06 per Common Share commencing in November 2021 and the conversion of the Company's $35 million of convertible debentures into Common Shares in the fourth quarter of 2021.

(2) Payout ratio is calculated as total annual dividends assuming a $0.06 per Common Share regular monthly dividend divided by forecast 2022 midpoint adjusted funds flow.

A capital program in this range would be expected to result in 2023 annual average sales volumes of between 97,500 Boe/d and 102,500 Boe/d (48 percent liquids) and free cash flow of approximately $450 million.(1)

FIVE-YEAR OUTLOOK

To highlight Paramount's free cash flow and production growth potential, the Company is providing an initial five-year outlook through to the end of 2026. At current strip prices and subject to change as conditions evolve, the Company anticipates:

- annual capital spending, excluding land acquisitions and abandonment and reclamation activities, of approximately $500 million;
- a compound annual production growth rate of approximately 5 percent; and
- cumulative free cash flow of over $2.7 billion.(2)

Paramount had total tax pools of approximately $4.7 billion as of September 30, 2021, including approximately $3.5 billion of immediately deductible non-capital loss and SR&ED pools. At current strip prices, the Company does not expect to pay Canadian income taxes within the next five years.

INCREASED DIVIDEND

Paramount's Board of Directors has approved an increase in the Company's regular monthly dividend from $0.02 to $0.06 per Common Share. The first increased dividend will be payable on November 30, 2021 to shareholders of record on November 15, 2021. The dividend will be designated as an "eligible dividend" for Canadian income tax purposes.

REDEMPTION OF CONVERTIBLE DEBENTURES

The Company has delivered notices to redeem all $35 million of its 7.5% senior unsecured convertible debentures, effective December 3, 2021. It is expected that all holders will exercise their right to convert their debentures into Common Shares prior to the redemption date, resulting in approximately 5.3 million Common Shares being issued.

(1) The free cash flow estimate is based on the following assumptions for 2023: (i) the midpoint of expected capital spending and production, (ii) $40 million in abandonment and reclamation costs, (iii) realized pricing of $48.55/Boe (US$67.39/Bbl WTI, US$3.56/MMBtu NYMEX, $3.28/GJ AECO), (iv) royalties of $5.95/Boe, (v) operating costs of $10.50/Boe and (vi) transportation and processing costs of $3.70/Boe.

(2) The stated anticipated cumulative free cash flow is based on the following assumptions: (i) the stated annual capital expenditures and compound annual production growth; (ii) approximately $40 million in average annual abandonment and reclamation costs, (iii) strip commodity prices and foreign exchange rates as at October 22, 2021, and (iv) internal management estimates of future royalties, operating costs and transportation and processing costs.

HEDGING

The Company's current hedging position is summarized below.

	Type (1)	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Average Price (2)
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	10,000	–	–	–	–	US$45.82/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	–	3,500	3,500	3,500	3,500	US$75.79/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	6,000	–	–	–	–	CDN$88.45/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	–	9,500	–	–	–	CDN$87.90/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	–	–	3,500	3,500	3,500	CDN$91.38/Bbl
Oil – WTI Costless Collars (Bbl/d)	Financial	–	7,000	7,000	7,000	7,000	CDN$82.50/Bbl (Floor) CDN$100.47/Bbl (Ceiling)
Condensate – Basis (Sale) (Bbl/d)	Physical	855	2,098	–	–	–	WTI + US$3.13/Bbl
Gas – NYMEX Swaps (Sale) (MMbtu/d)	Financial	110,000	–	–	–	–	US$3.37/MMbtu
Gas – NYMEX Swaps (Sale) (MMbtu/d)	Financial	–	40,000	–	–	–	US$4.15/MMbtu
Gas – AECO fixed price (GJ/d)	Physical	116,848	–	–	–	–	CDN$3.16/GJ
Gas – AECO fixed price (GJ/d)	Physical	–	40,000	–	–	–	CDN$4.06/GJ
Gas – AECO fixed price (GJ/d)	Physical	–	–	30,000	30,000	10,109	CDN$3.54/GJ

(1) Financial, refers to financial commodity contracts. Physical, refers to fixed-priced and basis physical contracts.
(2) Average price is calculated using a weighted average of notional volumes and prices.

REVIEW OF OPERATIONS

GRANDE PRAIRIE REGION

Grande Prairie Region sales volumes and netbacks are summarized below:(1)

	Q3 2021		Q2 2021		*% Change*
Sales volumes					
Natural gas (MMcf/d)	**148.0**		134.3		*10*
Condensate and oil (Bbl/d)	**26,648**		24,090		*11*
Other NGLs (Bbl/d)	**3,274**		2,874		*14*
Total (Boe/d)	**54,586**		49,345		*11*
% liquids	***55%***		*55%*		
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*% Change in $ millions*
Petroleum and natural gas sales	**275.8**	***54.92***	217.7	*48.47*	*27*
Royalties	**(20.5)**	***(4.08)***	(15.3)	*(3.40)*	*34*
Operating expense	**(52.6)**	***(10.47)***	(48.8)	*(10.88)*	*8*
Transportation and NGLs processing	**(22.5)**	***(4.48)***	(21.4)	*(4.76)*	*5*
	180.2	***35.89***	132.2	*29.43*	*36*

(1) "Netback" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.

KARR AREA

Karr sales volumes and netbacks are summarized below:

	Q3 2021		Q2 2021		*% Change*
Sales volumes					
Natural gas (MMcf/d)	**114.4**		107.6		*6*
Condensate and oil (Bbl/d)	**18,328**		18,458		*(1)*
Other NGLs (Bbl/d)	**2,477**		2,281		*9*
Total (Boe/d)	**39,878**		38,679		*3*
% liquids	***52%***		*54%*		
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*% Change in $ millions*
Petroleum and natural gas sales	**195.3**	***53.23***	168.0	*47.72*	*16*
Royalties	**(17.1)**	***(4.66)***	(13.1)	*(3.72)*	*31*
Operating expense	**(33.1)**	***(9.03)***	(33.1)	*(9.40)*	*-*
Transportation and NGLs processing	**(15.7)**	***(4.27)***	(16.0)	*(4.52)*	*(2)*
	129.4	***35.27***	105.8	*30.08*	*22*

Third quarter sales volumes at Karr averaged 39,878 Boe/d (52 percent liquids) compared to 38,679 Boe/d (54 percent liquids) in the second quarter. Plateau production of approximately 40,000 Boe/d that was first achieved in March has been sustained through efficient and reliable operations, continued strong performance from the six-well 3-10 pad that first produced in February and new well production from the five-well 7-18 pad that came onstream in late-July. The Company continues to seek efficiencies in its operations while maintaining its focus on safety, asset integrity, reliability and environmental performance.

The 7-18 pad has outperformed internal type well projections, averaging gross peak 30-day production per well of 2,137 Boe/d (6.4 MMcf/d of shale gas and 1,076 Bbl/d of NGLs) with an average CGR of 169 Bbl/MMcf.[(1)] The Company projects that this pad will achieve payout approximately five months after coming onstream.

While remaining sharply focused on maintaining well performance, Paramount continues to realize lower than historical DCET costs despite experiencing certain inflationary pressures. Preliminary DCET costs at the five-well Karr 5-16 East pad that was brought on production in late-October 2021 averaged $6.3 million per well, approximately 15 percent lower than average DCET costs of the 5-16 West pad that was brought onstream in the fourth quarter of 2020. Drilling operations are ongoing at the twelve-well 16-17 pad and the Company expects that seven of the twelve wells will be drilled by year-end. The 16-17 pad was initially planned as a ten well pad, but two additional wells were added prior to the commencement of drilling.

Karr unit operating costs trended lower in the third quarter as a result of higher production volumes and the Company's continued focus on capturing efficiencies and streamlining operations. Paramount achieved operating costs at Karr of $9.03/Boe in the third quarter of 2021, lower than targeted operating costs of $10.00/Boe at plateau production of approximately 40,000 Boe/d. The Company also achieved a record netback of $35.27/Boe at Karr in the third quarter.

In 2022, Paramount plans to maintain plateau production at Karr of 40,000 Boe/d by drilling 14 Montney wells and bringing onstream 16 wells, consistent with the Company's expectation that a total of 12 to 16 new wells per year are needed to maintain plateau production. The twelve-well 16-17 pad is currently being

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 6% and liquids sales volumes are lower by approximately 6% 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. CGR means condensate to gas ratio and is calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See "Oil and Gas Measures and Definitions" in the Advisories section.

drilled and will be brought on production in two phases, with the first seven wells scheduled to come onstream in the second quarter of 2022 and the remaining five wells to come onstream in the second half of the year. Drilling of the four-well 1-2 North pad is scheduled to commence in the second quarter and the Company plans to bring all four wells onstream in late-2022. The Company also plans to bring onstream additional gas lift compression in the year to support liquids production as well as build out certain infrastructure to debottleneck future production.

WAPITI AREA

Wapiti sales volumes and netbacks are summarized below:

	Q3 2021		Q2 2021		% Change
Sales volumes					
Natural gas (MMcf/d)	**33.3**		26.4		*26*
Condensate and oil (Bbl/d)	**8,310**		5,629		*48*
Other NGLs (Bbl/d)	**790**		582		*36*
Total (Boe/d)	**14,651**		10,604		*38*
% liquids	***62%***		*59%*		
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*% Change in $ millions*
Petroleum and natural gas sales	**80.4**	***59.62***	49.6	*51.41*	*62*
Royalties	**(3.4)**	***(2.49)***	(2.1)	*(2.24)*	*62*
Operating expense	**(19.2)**	***(14.25)***	(15.4)	*(16.00)*	*25*
Transportation and NGLs processing	**(6.9)**	***(5.09)***	(5.5)	*(5.65)*	*25*
	50.9	***37.79***	26.6	*27.52*	*91*

Third quarter sales volumes at Wapiti averaged 14,651 Boe/d (62 percent liquids) compared to 10,604 Boe/d (59 percent liquids) in the second quarter due to new well production from the seven-well 6-4 pad that was brought onstream in July. Gross peak 30-day production per well from the 6-4 pad averaged 1,292 Boe/d (3.0 MMcf/d of shale gas and 794 Bbl/d of NGLs) with an average CGR of 266 Bbl/MMcf.(1) Third quarter production was impacted by the previously disclosed scheduled ten-day outage at the third-party Wapiti natural gas processing facility.

Drilling operations at the seven-well 9-22 pad are now complete, with four of the seven wells having been configured as monobores. Compared with conventional multiple casing wellbores, monobore wells require less steel in the form of casing and less time on lease installing and cementing the additional casing, resulting in lower capital costs. Additional cost and well productivity benefits are also anticipated due to higher pumping rates afforded by the larger diameter wellbore. The Company plans to complete, tie-in and bring onstream four wells in December with the remaining three wells to be brought onstream in the first quarter of 2022.

As a result of capital cost savings achieved to date in 2021 and in support of reaching plateau production of 30,000 Boe/d at Wapiti in 2023, Paramount is accelerating the commencement of drilling operations of the eight-well 8-22 pad into 2021.

In 2022, the Company plans to grow Wapiti production to approximately 27,000 Boe/d by year end by drilling 32 wells and bringing onstream a total of 22 wells. Drilling, completion and tie-in activities at the eight-well 8-22 pad are scheduled to commence in late-2021 and continue through the first half of 2022,

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 13% and liquids sales volumes are lower by approximately 1% 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. CGR means condensate to gas ratio and is calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See Oil and Gas Measures and Definitions in the Advisories section.

with the majority of the wells to be brought onstream in the second quarter of 2022. Paramount plans to drill, complete and tie-in two additional eight-well pads, at 6-32 and 16-15, with drilling scheduled for the second and third quarters of 2022 respectively. The 6-32 pad is expected to be onstream in the second half of 2022 while the majority of the 16-15 pad wells will be brought onstream in early 2023. Drilling of the eight-well 8-15 pad is scheduled for late 2022. The Company also plans to complete a tenure well in 2022.

KAYBOB REGION

Kaybob Region sales volumes averaged 21,054 Boe/d (28 percent liquids) in the third quarter of 2021 compared to 22,688 Boe/d (28 percent liquids) in the second quarter. The decrease in production is largely attributable to natural declines.

In 2022, Paramount plans to pursue the development of its Duvernay assets at Kaybob North and Kaybob Smoky. At Kaybob North, the Company plans to drill the remaining two wells at the three-well 12-21 pad and bring all three wells onstream in the second half of 2022. At Kaybob Smoky, plans include the expansion of the Company's 100% owned and operated 6-16 facility and the drilling, completion, tie-in and bringing onstream of the four-well 10-35 pad, also in the second half of 2022.

The Company expects to realize capital cost efficiencies in its Kaybob Duvernay plays, similar to those achieved over the past two years at Karr and Wapiti, as it commences pad development and captures economies of scale.

The Company plans to pursue other high return opportunities at Kaybob in 2022, including bringing onstream four Montney gas wells, two Montney oil wells and two Gething oil wells, seven of which will be drilled in 2022. Other activities include an expansion of the enhanced oil recovery scheme at the Company's Kaybob Montney Oil property.

CENTRAL ALBERTA & OTHER REGION

Central Alberta & Other Region sales volumes averaged 6,510 Boe/d (22 percent liquids) in the third quarter of 2021 compared to 7,962 Boe/d (13 percent liquids) in the second quarter. Sales volumes in the third quarter decreased primarily due to the sale of the non-operated Birch assets in July and, to a lesser extent, a third-party pipeline outage and natural declines. New well production from the two-well Willesden Green Duvernay 4-7 pad that was brought on production in July partially offset these decreases. Despite being restricted by facility constraints, average gross peak 30-day production per well at the 4-7 pad was 1,498 Boe/d (3.3 MMcf/d of shale gas and 948 Bbl/d of NGLs) with an average CGR of 287 Bbl/MMcf.

The Company holds a material, contiguous Duvernay position at Willesden Green and continues to actively evaluate longer-term full field development plans for this asset. Material learnings from the drilling of the two wells at the 4-7 pad, particularly in drilling long reach laterals in the Duvernay formation, have resulted in further optimization to pad layouts in the full field development plans across the Company's Duvernay lands, improving economics. DCET costs at the 4-7 pad averaged $11.3 million per well. The Company anticipates reductions in average well costs once commercial scale development commences and critical infrastructure is in place.

In 2022, planned activities include the addition of water infrastructure and FEED studies for future facility expansion that will benefit Duvernay development in the Willesden Green area.

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 reserves and resources, including longer-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 2021 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.

A summary of historical financial and operating results is also available on Paramount's website at https://www.paramountres.com/investors/financial-shareholder-reports/.

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FINANCIAL AND OPERATING RESULTS [1]

($ millions, except as noted)	Q3 2021		Q2 2021	
Net income (loss)		292.7		(74.3)
per share – basic ($/share)		*2.20*		*(0.56)*
per share – diluted ($/share)		*2.06*		*(0.56)*
Cash from operating activities		97.0		112.1
per share – basic ($/share)		*0.73*		*0.84*
per share – diluted ($/share)		*0.68*		*0.84*
Adjusted funds flow		148.4		86.0
per share – basic ($/share)		*1.12*		*0.65*
per share – diluted ($/share)		*1.04*		*0.65*
Total assets		3,882.9		3,655.6
Long-term debt		522.4		608.4
Net debt		576.8		724.5
Common shares outstanding *(thousands)* [2]		133,207		133,314
Sales volumes				
Natural gas (MMcf/d)		269.7		273.1
Condensate and oil (Bbl/d)		32,177		29,543
Other NGLs (Bbl/d) [3]		5,017		4,938
Total (Boe/d)		82,150		79,995
% liquids		*45%*		*43%*
Grande Prairie Region (Boe/d)		54,586		49,345
Kaybob Region (Boe/d)		21,054		22,688
Central Alberta & Other Region (Boe/d)		6,510		7,962
Total (Boe/d)		82,150		79,995
Netback		*$/Boe* [3]		*$/Boe* [3]
Natural gas revenue	96.5	*3.89*	74.8	*3.01*
Condensate and oil revenue	249.9	*84.42*	209.6	*77.96*
Other NGLs revenue	21.7	*47.05*	14.4	*32.11*
Royalty and other revenue	1.0	—	0.9	—
Petroleum and natural gas sales	369.1	*48.84*	299.7	*41.17*
Royalties	(30.9)	*(4.09)*	(24.9)	*(3.43)*
Operating expense	(83.3)	*(11.02)*	(81.8)	*(11.23)*
Transportation and NGLs processing [4]	(30.3)	*(4.01)*	(30.3)	*(4.16)*
Netback	224.6	*29.72*	162.7	*22.35*
Financial commodity contract settlements	(59.0)	*(7.81)*	(54.1)	*(7.44)*
Netback including financial commodity contract settlements	165.6	*21.91*	108.6	*14.91*
Total Capital Expenditures				
Grande Prairie Region		53.1		66.5
Kaybob Region		1.7		3.9
Central Alberta & Other Region		9.7		11.8
Corporate [5]		1.6		1.2
Land acquisitions		2.8		0.1
Total capital expenditures		68.9		83.5
Asset retirement obligation settlements		6.9		3.2

(1) Readers are referred to the advisories concerning Non-GAAP Financial Measures and Oil and Gas Measures and Definitions in the Advisories section of this document. This table contains the following Non-GAAP financial measures: Adjusted funds flow, Net debt, Netback and Total capital expenditures. Readers are referred to the Product Type Information section of this document for a complete breakdown of sales volumes for applicable periods by the specific product types.
(2) Presented net of shares held in trust under the Company's restricted share unit plan (000's of common shares): Q3 2021: 1,536 and Q2 2021: 1,538.
(3) Natural gas revenue presented as $/Mcf.
(4) Includes downstream transportation costs and NGLs fractionation costs.
(5) Includes transfers between regions.

PRODUCT TYPE INFORMATION

This press release refers to sales volumes of "natural gas", "condensate and oil", "NGLs", "Other NGLs" and "Liquids". "Natural gas" refers to conventional natural gas and shale gas combined. "Condensate and oil" refers to condensate, light and medium crude oil and tight oil combined. "NGLs" refers to condensate and Other NGLs combined. "Other NGLs" refers to ethane, propane and butane combined. "Liquids" refers to condensate and oil and Other NGLs combined. Below is a complete breakdown of sales volumes for applicable periods by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil. Numbers may not add due to rounding.

	Total		Grande Prairie Region		Kaybob Region		Central Alberta & Other Region	
	Q3 2021	Q2 2021	Q3 2021	Q2 2021	Q3 2021	Q2 2021	Q3 2021	Q2 2021
Shale gas (MMcf/d)	**207.1**	205.8	**145.8**	132.2	**36.9**	39.3	**24.4**	34.3
Conventional natural gas (MMcf/d)	**62.6**	67.3	**2.2**	2.1	**54.4**	58.0	**6.0**	7.2
Natural gas (MMcf/d)	**269.7**	273.1	**148.0**	134.3	**91.3**	97.3	**30.4**	41.5
Condensate (Bbl/d)	**29,670**	26,784	**26,639**	24,086	**2,072**	2,319	**959**	379
Other NGLs (Bbl/d)	**5,017**	4,938	**3,274**	2,874	**1,415**	1,569	**328**	495
NGLs (Bbl/d)	**34,687**	31,722	**29,913**	26,960	**3,487**	3,888	**1,287**	874
Tight oil (Bbl/d)	**475**	494	**–**	–	**368**	354	**107**	140
Light and medium crude oil (Bbl/d)	**2,032**	2,265	**9**	4	**1,979**	2,224	**44**	37
Crude oil (Bbl/d)	**2,507**	2,759	**9**	4	**2,347**	2,578	**151**	177
Total (Boe/d)	**82,150**	79,995	**54,586**	49,345	**21,054**	22,688	**6,510**	7,962

	Karr		Wapiti	
	Q3 2021	Q2 2021	Q3 2021	Q2 2021
Shale gas (MMcf/d)	**113.0**	106.3	**32.7**	25.9
Conventional natural gas (MMcf/d)	**1.4**	1.3	**0.6**	0.5
Natural gas (MMcf/d)	**114.4**	107.6	**33.3**	26.4
NGLs (Bbl/d)	**20,805**	20,739	**9,100**	6,211
Total (Boe/d)	**39,878**	38,679	**14,651**	10,604

The Company forecasts that fourth quarter 2021 sales volumes will average between 85,000 Boe/d and 86,500 Boe/d (55 percent shale gas and conventional natural gas combined, 39 percent light and medium crude oil, tight oil and condensate combined and 6 percent other NGLs).

The Company forecasts that 2021 annual sales volumes will average approximately 82,000 Boe/d (56 percent shale gas and conventional natural gas combined, 38 percent light and medium crude oil, tight oil and condensate combined and 6 percent other NGLs).

The Company forecasts that 2022 sales volumes will average between 90,000 Boe/d and 94,000 Boe/d (54 percent shale gas and conventional natural gas combined, 40 percent light and medium crude oil, tight oil and condensate combined and 6 percent other NGLs). First half 2022 sales volumes are expected to average between 81,000 Boe/d and 85,000 Boe/d (56 percent shale gas and conventional natural gas combined, 38 percent light and medium crude oil, tight oil and condensate combined and 6 percent other NGLs). Second half 2022 sales volumes are expected to average between 99,000 Boe/d and 103,000 Boe/d (53 percent shale gas and conventional natural gas combined, 41 percent light and medium crude oil, tight oil and condensate combined and 6 percent other NGLs).

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:

- forecast free cash flow in 2021 and 2022;
- forecast 2021 year-end net debt to annual adjusted funds flow;
- planned capital expenditures in 2021 and 2022;
- forecast sales volumes for 2021 and 2022 and certain periods therein;
- the expectation that plateau production will be reached at Wapiti in 2023;
- the anticipated meeting by the Company of its $300 million net debt target by the end of the third quarter of 2022 and the implied net debt to adjusted funds flow ratio at the end of the third quarter of 2022;
- the Company's priorities and expectations respecting the allocation of free cash flow;
- planned abandonment and reclamation expenditures and activities in 2022;
- preliminary anticipated capital expenditures in 2023 and the resulting expected 2023 average sales volumes and free cash flow;
- the Company's five-year outlook for capital spending, annual production growth rate and cumulative free cash flow;
- the Company's expectation that it will not be required to pay Canadian income taxes within the next five years;
- the expectation that all holders will exercise their right to convert their debentures into Common Shares prior to the redemption date;
- planned exploration, development and production activities, including the expected timing of completing and bringing new wells on production;
- the expectation that a total of 12 to 16 wells per year are needed to maintain plateau production at Karr;
- preliminary estimated drilling, completion and equipping costs;
- the payment of future dividends under the Company's monthly dividend program; and
- expected capital cost efficiencies at the Company's Kaybob Duvernay properties and the expectation that average well costs at the Company's Duvernay properties will be reduced once commercial scale development commences.

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 commodity prices and the potential impact of the COVID-19 pandemic thereon;
- the likely impact of the COVID-19 pandemic on operations;
- the ability to realize expected cost savings;
- royalty rates, taxes and capital, operating, processing, transportation, general & administrative and other costs;
- foreign currency exchange rates and interest rates;
- general business, economic and market conditions;
- the performance of wells and facilities;
- 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 and the capacity and reliability of facilities;
- the ability of Paramount to market its production 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, product yields and resource recoveries) and operational improvements, efficiencies and results consistent with expectations;
- the timely receipt of required governmental and regulatory approvals;
- the receipt of benefits under government programs;
- the application of regulatory requirements respecting abandonment and reclamation;
- in the case of the expectation that all holders will exercise their right to convert their debentures into Common Shares prior to the redemption date, the assumption that the trading price of the Common Shares will continue to remain substantially above the conversion price of the debentures; and
- anticipated timelines and budgets being met in respect of drilling programs and other operations (including well completions and tie-ins, the construction, commissioning and start-up of new and expanded facilities, including third-party facilities, and facility turnarounds and maintenance).

In addition to the above, the Company's expectation to not pay Canadian income taxes within the next five years is based on the current tax regime, the Company's tax pools and the assumptions with respect to production, expenditures, commodity prices, royalties and costs in the five years ended 2026 set forth herein. Taxable income varies depending on total income and expenses and Paramount's estimate is sensitive to assumptions regarding commodity prices, production, cash from operating activities, capital spending levels and acquisition and disposition transactions. Changes in these factors could result in the Company paying income taxes earlier than expected.

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 commodity prices, including in relation to the impact of the COVID-19 pandemic;
- changes in capital spending plans and planned exploration and development activities;
- the potential for changes to preliminary anticipated 2023 capital expenditures prior to finalization and changes to the resulting expected 2023 average sales volumes and free cash flow;
- the potential for changes to the Company's five-year outlook for capital spending, annual production growth rate and cumulative free cash flow;
- changes in foreign currency exchange rates and interest rates;
- the uncertainty of estimates and projections relating to future revenue, free cash flow, production, reserves additions, product 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 from operating activities 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 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, insurance claims, 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.

There are risks that may result in the Company changing, suspending or discontinuing its monthly dividend program, including changes to free cash flow, operating results, capital requirements, financial position, market conditions or corporate strategy and the need to comply with requirements under debt agreements and applicable laws respecting the declaration and payment of dividends. There are no assurances as to the continuing declaration and payment of future dividends under the Company's monthly dividend program or the amount or timing of any such dividends.

The foregoing list of risks is not exhaustive. For more information relating to risks, see the sections titled "*Risk Factors*" in Paramount's annual information form for the year ended December 31, 2020, 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.

Certain forward-looking information in this press release, including forecast free cash flow in 2021, 2022 and future periods and forecast 2021 and 2022 net debt to annual adjusted funds flow ratios, may also constitute a "financial outlook" within the meaning of applicable securities laws. A financial outlook involves statements about Paramount's prospective financial performance or position and is based on and subject to the assumptions and risk factors described above in respect of forward-looking information generally as well as any other specific assumptions and risk factors in relation to such financial outlook noted in this press release. Such assumptions are based on management's assessment of the relevant information currently available and any financial outlook included in this press release is provided for the purpose of helping readers understand Paramount's current expectations and plans for the future. Readers are cautioned that reliance on any financial outlook may not be appropriate for other purposes or in other circumstances and that the risk factors described above or other factors may cause actual results to differ materially from any financial outlook.

Non-GAAP Financial Measures

In this press release, "adjusted funds flow", "free cash flow", "netback", "net debt", "net debt to adjusted funds flow" and "total capital expenditures", together the "Non-GAAP financial measures", are used and do not have any standardized meanings as prescribed by International Financial Reporting Standards.

"Adjusted funds flow" refers to cash from (used in) operating activities before net changes in non-cash working capital, geological and geophysical expenses, asset retirement obligation settlements, closure costs, provisions and other, dispute settlements 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 obligation 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 managing its asset retirement obligations and, as a result, amounts incurred may vary significantly 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 are the calculations of adjusted funds flow from the nearest GAAP measure for the three months ended September 30, 2021 and June 30, 2021:

Three months ended	Sept 30, 2021 (MM$)	Jun 30, 2021 (MM$)
Cash from operating activities	**97.0**	**112.1**
Change in non-cash working capital	42.9	(47.6)
Geological and geophysical expenses	1.6	1.8
Asset retirement obligations settled	6.9	3.2
Closure costs	–	–
Provisions and other	–	16.5
Dispute settlements	–	–
Transaction and reorganization costs	–	–
Adjusted funds flow	**148.4**	**86.0**

"Free cash flow" refers to adjusted funds flow less total capital expenditures and asset retirement obligation settlements. Free cash flow is used by management and investors to assess the amount of internally generated cash available to repay debt, reinvest in the business or return to shareholders. The following is the calculation of free cash flow from the nearest GAAP measure for the three months ended September 30, 2021 and June 30, 2021:

Three months ended	Sept 30, 2021 (MM$)	Jun 30, 2021 (MM$)
Adjusted funds flow	**148.4**	**86.0**
Total capital expenditures	(68.9)	(83.5)
Asset retirement obligation settlements	(6.9)	(3.2)
Free cash flow	**72.6**	**(0.7)**

"Netback" equals petroleum and natural gas sales less royalties, operating expense 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 tables under the headings "Review of Operations" and "Financial and Operating Results" 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 the Company's Management's Discussion and Analysis for the three months and nine months ended September 30, 2021 (the "MD&A") for the calculation of net debt.

"Net debt to adjusted funds flow" is a ratio calculated as the period end net debt divided by adjusted funds flow for the trailing four quarters. The ratio of net debt to adjusted funds flow is commonly used by management and investors to assess the Company's overall debt position.

"Total capital expenditures" refers to the Company's property, plant and equipment and exploration expenditures. Refer to the Total Capital Expenditures section of the MD&A for the calculation thereof.

Non-GAAP financial 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 financial measures are unlikely to be comparable to similar measures presented by other issuers.

Oil and Gas Measures and Definitions

Abbreviations

Liquids	
Bbl	Barrels
Bbl/d	Barrels per day
MBbl	Thousands of barrels
NGLs	Natural gas liquids
Condensate	Pentane and heavier hydrocarbons
WTI	West Texas Intermediate

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

Oil Equivalent	
Boe	Barrels of oil equivalent
MBoe	Thousands of barrels of oil equivalent
MMBoe	Millions of barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day

This press release 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, 2021, the value ratio between crude oil and natural gas was approximately 26:1. 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 refers to "CGR", a metric commonly used in the oil and natural gas industry. "CGR" means condensate to gas ratio and is calculated by dividing wellhead raw liquids volumes by wellhead raw natural gas volumes. This metric 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.

Additional information respecting the Company's oil and gas properties and operations is provided in the Company's annual information form for the year ended December 31, 2020 which is available on SEDAR at www.sedar.com.

Management's Discussion and Analysis
For the three and nine months ended September 30, 2021

This Management's Discussion and Analysis ("MD&A"), dated November 3, 2021 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, 2021 (the "Interim Financial Statements") and Paramount's audited Consolidated Financial Statements as at and for the year ended December 31, 2020 (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.

The disclosures in this document include forward-looking information and financial outlooks, non-GAAP financial measures and certain oil and gas measures. Readers are referred to the Advisories section of this document concerning such matters. Certain comparative figures have been reclassified to conform to the current years' presentation. 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 reserves and resources. Paramount's principal properties are located in Alberta and British Columbia. Paramount commenced operations as a public company in 1978 and has adapted to a multitude of operating and economic climates over the years. The Company's Class A common shares ("Common Shares") are listed on the Toronto Stock Exchange under the symbol "POU".

Paramount's operations are organized into the following three regions:

- the Grande Prairie Region, located in the Peace River Arch area of Alberta, which is focused on Montney developments at Karr and Wapiti;
- the Kaybob Region, located in west-central Alberta, which includes the Kaybob North and Ante Creek Montney oil developments, Duvernay developments at Kaybob Smoky, Kaybob North and Kaybob South and other shale gas and conventional natural gas producing properties; and
- the Central Alberta & Other Region, which includes the Willesden Green Duvernay development in central Alberta and shale gas producing properties in the Horn River Basin in northeast British Columbia.

The Company's assets include: (i) strategic investments in exploration and pre-development stage assets, including prospective shale gas acreage in the Liard Basin, prospective natural gas and oil acreage in the Mackenzie Delta and Central Mackenzie and interests held by the Company's wholly-owned subsidiary Cavalier Energy Inc. prospective for in-situ thermal oil recovery and heavy oil production; (ii) drilling rigs owned by the Company's wholly-owned limited partnership Fox Drilling Limited Partnership; and (iii) investments in other entities.

NOTE REGARDING PRODUCT TYPES

This MD&A includes references to sales volumes of "natural gas", "condensate and oil", "NGLs", "Other NGLs" and "Liquids". "Natural gas" refers to conventional natural gas and shale gas combined. "Condensate and oil" refers to condensate, light and medium crude oil and tight oil combined. "NGLs" refers to condensate and Other NGLs combined. "Other NGLs" refers to ethane, propane and butane combined. "Liquids" refers to condensate and oil and Other NGLs combined. Readers are referred to the Product

Type Information section of this document for a complete breakdown of sales volumes for applicable periods by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

FINANCIAL AND OPERATING HIGHLIGHTS (1) (2)

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
FINANCIAL				
Petroleum and natural gas sales	369.1	138.8	948.7	424.0
Net income (loss)	292.7	(23.3)	135.9	(334.1)
Per share – basic ($/share)	*2.20*	*(0.17)*	*1.02*	*(2.50)*
Per share – diluted ($/share)	*2.06*	*(0.17)*	*0.97*	*(2.50)*
Cash from operating activities	97.0	11.4	290.4	27.7
Per share – basic ($/share)	*0.73*	*0.09*	*2.18*	*0.21*
Per share – diluted ($/share)	*0.68*	*0.09*	*2.06*	*0.21*
Adjusted funds flow	148.4	29.5	325.3	82.1
Per share – basic ($/share)	*1.12*	*0.22*	*2.45*	*0.61*
Per share – diluted ($/share)	*1.04*	*0.22*	*2.31*	*0.61*
Total assets			3,882.9	3,041.9
Long-term debt			522.4	792.7
Net debt			576.8	836.5
Total liabilities			1,471.8	1,336.5
Dividends declared ($/share)	0.06	–	0.06	–
Common shares outstanding (thousands) (3)			133,207	133,784
OPERATIONAL				
Sales volumes				
Natural gas (MMcf/d)	269.7	224.0	272.0	246.1
Condensate and oil (Bbl/d)	32,177	19,782	30,533	21,495
Other NGLs (Bbl/d)	5,017	3,952	5,041	4,102
Total (Boe/d)	82,150	61,064	80,901	66,621
% Liquids	*45%*	*39%*	*44%*	*38%*
Realized prices				
Natural gas ($/Mcf)	3.89	1.94	3.35	2.05
Condensate and oil ($/Bbl)	84.42	48.74	77.43	44.23
Other NGLs ($/Bbl)	47.05	18.10	37.18	13.60
Petroleum and natural gas sales ($/Boe)	48.84	24.70	42.96	23.23
Total capital expenditures	68.9	50.5	211.7	155.8

(1) Readers are referred to the advisories concerning Non-GAAP financial measures and Oil and Gas Measures and Definitions in the Advisories section and to the reconciliations of such Non-GAAP financial measures to their most directly comparable measure under GAAP in the applicable sections of this document. This table contains the following Non-GAAP financial measures: Adjusted funds flow, Net debt and Total capital expenditures.

(2) "Natural gas" refers to conventional natural gas and shale gas combined. "Condensate and oil" refers to condensate, light and medium crude oil and tight oil combined. "Other NGLs" refers to ethane, propane and butane combined. Readers are referred to the Product Type Information section of this document for a complete breakdown of sales volumes and revenues for all applicable periods by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

(3) Common Shares are presented net of shares held in trust under the Company's restricted share unit plan (000's of Common Shares): 2021: 1,536 and 2020: 414.

Q3 2021 OVERVIEW

In the third quarter of 2021, Paramount delivered production results in line with guidance, achieved reductions in per unit operating costs and generated significant free cash flow that was used to reduce indebtedness and fund shareholder returns through dividends and purchases of Common Shares under the Company's normal course issuer bid ("NCIB") program.

Sales volumes averaged 82,150 Boe/d (45% liquids) in the third quarter of 2021 compared to 79,995 Boe/d (43% liquids) in the second quarter. Sales volumes at Karr averaged 39,878 Boe/d (52% liquids) in the third quarter compared to 38,679 Boe/d (54% liquids) in the second quarter. Sales volumes at Wapiti averaged 14,651 Boe/d (62% liquids) in the third quarter compared to 10,604 Boe/d (59% liquids) in the second quarter. The quarter-over-quarter increase in production at Wapiti occurred despite a ten-day scheduled plant outage and was mainly the result of new well production from a seven-well pad that was brought onstream in July 2021.

Crude oil and condensate prices continued to strengthen in the third quarter of 2021 as the global economy and energy demand recover from the COVID-19 pandemic and supply increases remain tempered. Paramount also benefited from significant increases in natural gas prices in the third quarter. The recovery and pricing conditions remain, in part, dependent on the course of the COVID-19 pandemic. The Company continues to proactively respond to the pandemic and the risks that it poses, including the risks described in this MD&A under "Risk Factors".

Operating costs averaged $11.02/Boe in the third quarter of 2021, down from $11.23/Boe in the second quarter. Karr operating costs averaged $9.03/Boe in the third quarter of 2021, down from $9.40/Boe in the second quarter.

Third quarter capital expenditures, which were focused on drilling and completion activities at Karr, Wapiti, and the Willesden Green Duvernay, totaled $68.9 million. Preliminary all-in lease construction, drilling, completion, equip and tie-in costs at the five-well Karr 5-16 East pad that was brought on production in late October 2021 averaged $6.3 million per well, approximately 15 percent lower than average costs at the 5-16 West pad that was brought onstream in the fourth quarter of 2020. The Company continues to achieve lower costs in its Karr and Wapiti drilling and completion programs despite emerging industry cost inflation by utilizing its wholly-owned Fox Drilling rigs and crews and securing fixed rates with certain service providers.

Cash from operating activities was $97.0 million in the third quarter of 2021 compared to $112.1 million in the second quarter. Adjusted funds flow was $148.4 million in the third quarter of 2021 compared to $86.0 million in the second quarter. Free cash flow was $72.6 million in the third quarter compared to ($0.7) million in the second quarter. The free cash flow generated during the quarter, along with proceeds of dispositions, was allocated to: (i) the reduction of indebtedness, contributing to a $147.7 million reduction in net debt quarter-over-quarter to $576.8 million, (ii) the payment of the $0.02 per Common Share regular monthly dividend implemented in July 2021 and (iii) the repurchase for cancellation of 197,500 Common Shares under the NCIB. See "Liquidity and Capital Resources" in this MD&A.[1]

In July 2021, the Company closed the sale of its non-operated Birch assets for proceeds of approximately $85 million.

(1) "Adjusted funds flow", "Free cash flow" and "Net debt" are Non-GAAP financial measures. See "Non-GAAP Financial Measures" in the Advisories section.

UPDATED 2021 GUIDANCE

Paramount expects fourth quarter sales volumes to range between 85,000 Boe/d and 86,500 Boe/d (45 percent liquids). As a result, full year 2021 sales volumes are expected to average approximately 82,000 Boe/d (44 percent liquids), achieving the high end of the previous guidance range of 80,000 Boe/d to 82,000 Boe/d, 1,000 Boe/d higher than the mid-point.

The Company has added approximately $15 million of capital expenditures in the second half of 2021, which include additional activities at Wapiti to accelerate the achievement of targeted plateau production of 30,000 Boe/d into 2023 and further debottlenecking initiatives at Karr. Full year 2021 capital spending is now expected to be between $285 and $295 million.

Paramount is forecasting 2021 free cash flow of approximately $215 million, an increase of $30 million from previous guidance. The increase reflects year-to-date actual results, updated sales volumes guidance and revised commodity price and other assumptions for the fourth quarter of 2021. The forecast is based on the following assumptions for 2021: (i) the midpoint of forecast capital spending and production, (ii) $25 million in net abandonment and reclamation costs, (iii) realized pricing of $47.55/Boe (US$67.63/Bbl WTI, US$3.94/MMBtu NYMEX, $3.59/GJ AECO), (iv) royalties of $4.60/Boe, (v) operating costs of $11.15/Boe and (vi) transportation and processing costs of $4.00/Boe.

Year-end net debt to adjusted funds flow is forecast to be approximately 0.8x, below the Company's previous guidance of 1.0x.(1)

2022 BUDGET AND GUIDANCE

The Company's 2022 capital budget is expected to range between $500 million and $540 million, excluding land acquisitions and abandonment and reclamation activities, an increase of $165 million at midpoint from preliminary guidance. The budget includes the acceleration of approximately $70 million in activities at Wapiti, $60 million to advance a number of high return opportunities in the Kaybob and Central Alberta & Other Regions and additional growth capital that will primarily benefit 2023 production. Paramount remains committed to prudently managing its capital resources and has the flexibility to adjust its capital expenditure plans depending on commodity prices and other factors.

Annual average sales volumes in 2022 are now expected to be between 90,000 Boe/d and 94,000 Boe/d (46% liquids), an increase of 6,000 Boe/d from previous preliminary guidance.

- First half 2022 sales volumes are expected to average between 81,000 Boe/d and 85,000 Boe/d (44% liquids) after accounting for a planned 16-day full field outage at Karr for turnaround activities at third-party midstream facilities.
- Second half 2022 sales volumes are expected to average between 99,000 Boe/d and 103,000 Boe/d (47% liquids) as numerous wells are brought onstream related to capital activities initiated earlier in 2022.

Paramount is forecasting approximately $455 million of free cash flow in 2022, $135 million higher than the Company's prior preliminary guidance. The free cash flow forecast is based on the following assumptions for 2022: (i) the midpoint of forecast capital spending and production, (ii) $33 million in net abandonment and reclamation costs, (iii) realized pricing of $53.70/Boe (US$74.44/Bbl WTI, US$4.35/MMBtu NYMEX,

(1) "Net debt to adjusted funds flow" is Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section. The forecast of year end net debt to adjusted funds flow assumes the payment of a regular monthly dividend of $0.06 per Common Share commencing in November 2021 and the conversion of the Company's $35 million of convertible debentures into Common Shares in the fourth quarter of 2021.

$3.95/GJ AECO), (iv) royalties of $6.65/Boe, (v) operating costs of $11.00/Boe and (vi) transportation and processing costs of $3.85/Boe.

The 2022 capital budget is broken down as follows at midpoint:

- $290 million of sustaining capital and maintenance activities;
- $160 million of growth capital associated with production benefits in 2022; and
- $70 million of growth capital associated with production benefits largely in 2023.

The breakdown by region is as follows at midpoint:

- Grande Prairie − $365 million;
- Kaybob − $130 million;
- Central Alberta & Other − $10 million; and
- Corporate − $15 million.

The Company has budgeted approximately $41 million for abandonment and reclamation activities in 2022. Approximately $8 million is to be funded directly through the Alberta Site Rehabilitation Program (the "ASRP"), resulting in approximately $33 million net to Paramount. The majority of these funds will be directed to the Zama area.

FREE CASH FLOW PRIORITIES

Paramount's free cash flow priorities continue to be (i) the achievement of targeted leverage levels, (ii) shareholder returns and (iii) incremental growth.

- With strong 2021 performance and commodity prices, the Company expects year-end 2021 net debt to adjusted funds flow will be approximately 0.8x, below the previously targeted range of 1.0x to 2.0x.
- The Company is reducing its targeted long-term leverage level to approximately $300 million in net debt. This target is expected to be achieved in the third quarter of 2022, implying a net debt to trailing 12-month adjusted funds flow ratio of less than 0.5x at the end of that quarter.(1)
- Paramount implemented a regular monthly dividend of $0.02 per share in July 2021. On November 4, 2021, the Company announced that it is tripling its regular monthly dividend to $0.06 per share beginning in November 2021.
- Remaining 2022 free cash flow will be available to:
    - further augment shareholder returns through increases in the regular monthly dividend, special dividends or opportunistic repurchases of Common Shares under the NCIB; and
    - reinvest in incremental organic growth or strategic acquisitions.

Paramount has hedged approximately 23 percent of its 2022 midpoint forecast production to provide greater free cash flow certainty. With these hedges, the Company's 2022 capital program, targeted net debt reduction and $0.06 per share regular monthly dividend would remain fully funded down to an annual

(1) The forecasted timing of achieving the targeted net debt level and net debt to adjusted funds flow assumes the payment of a regular monthly dividend of $0.06 per Common Share commencing in November 2021 and the conversion of the Company's $35 million of convertible debentures into Common Shares in the fourth quarter of 2021.

average WTI price of approximately US$52.50/Bbl with no changes to the Company's natural gas pricing assumptions. See "Operating Results – Financial Commodity Contracts".

PRELIMINARY 2023 GUIDANCE

Based on preliminary planning and current market conditions, Paramount anticipates 2023 capital spending, excluding land acquisitions and abandonment and reclamation activities, to range between $475 million and $525 million, broken down as follows at midpoint:

- $330 million of sustaining capital and maintenance activities; and
- $170 million of growth capital.

The breakdown by region is as follows at midpoint:

- Grande Prairie − $295 million;
- Kaybob − $170 million;
- Central Alberta & Other − $25 million; and
- Corporate − $10 million.

A capital program in this range would be expected to result in 2023 annual average sales volumes of between 97,500 Boe/d and 102,500 Boe/d (48% liquids) and free cash flow of approximately $450 million. The free cash flow estimate is based on the following assumptions for 2023: (i) the midpoint of expected capital spending and production, (ii) $40 million in abandonment and reclamation costs, (iii) realized pricing of $48.55/Boe (US$67.39/Bbl WTI, US$3.56/MMBtu NYMEX, $3.28/GJ AECO), (iv) royalties of $5.95/Boe, (v) operating costs of $10.50/Boe and (vi) transportation and processing costs of $3.70/Boe.

CONSOLIDATED RESULTS

Net Income (Loss)

Paramount recorded net income of $292.7 million for the three months ended September 30, 2021 compared to a net loss of $23.3 million in the same period in 2020. Significant factors contributing to the change are shown below:

Three months ended September 30	
Net loss – 2020	**(23.3)**
• Lower depletion, depreciation and impairment (reversal) in 2021, mainly due to impairment reversals of $282.6 million, partially offset by a lower recovery related to changes in asset retirement obligations and higher depletion expense in 2021	238.8
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	180.3
• Gain on the sale of oil and gas assets in 2021 compared to a loss in 2020	40.3
• Lower interest and financing expense in 2021	8.4
• Income tax expense in 2021 compared to a recovery in 2020	(107.6)
• Higher loss on financial commodity contracts in 2021	(44.9)
• Other	0.7
Net income – 2021	**292.7**

Paramount recorded net income of $135.9 million for the nine months ended September 30, 2021 compared to a net loss of $334.1 million in the same period in 2020. Significant factors contributing to the change are shown below:

Nine months ended September 30	
Net loss – 2020	**(334.1)**
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	426.0
• Lower depletion, depreciation and impairment (reversal) in 2021, mainly due to impairment reversals of $296.6 million in 2021 compared to impairment charges of $191.8 million in 2020, partially offset by a charge related to changes in asset retirement obligations in 2021 compared to a recovery in 2020	227.1
• Gain on the sale of oil and gas assets in 2021 compared to a loss in 2020	80.8
• Lower income tax expense in 2021; 2020 included the derecognition of $130.0 million of the deferred income tax asset	25.6
• Loss on financial commodity contracts in 2021 compared to a gain in 2020	(236.9)
• Loss on settlement of dissent payment entitlement in 2021	(22.6)
• Higher provisions in 2021	(19.3)
• Higher general and administrative expense in 2021, mainly due to the receipt of benefits under the Canada Emergency Wage Subsidy ("CEWS") program in 2020	(5.9)
• Other	(4.8)
Net income – 2021	**135.9**

Cash From Operating Activities

Cash from operating activities for the three months ended September 30, 2021 was $97.0 million compared to cash from operating activities of $11.4 million for the same period in 2020. Significant factors contributing to the change are shown below:

Three months ended September 30	
Cash from operating activities – 2020	**11.4**
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	180.3
• Lower interest and financing expense in 2021	8.8
• Payments on financial commodity contract settlements in 2021 compared to receipts in 2020	(68.8)
• Change in non-cash working capital	(27.3)
• Higher asset retirement obligation settlements in 2021	(6.1)
• Other	(1.3)
Cash from operating activities – 2021	**97.0**

Cash from operating activities for the nine months ended September 30, 2021 was $290.4 million compared to $27.7 million for the same period in 2020. Significant factors contributing to the change are shown below:

Nine months ended September 30	
Cash from operating activities – 2020	**27.7**
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	426.0
• Change in non-cash working capital	18.0
• Lower asset retirement obligation settlements in 2021	16.6
• Payments on financial commodity contract settlements in 2021 compared to receipts in 2020	(175.5)
• Higher provisions in 2021	(19.3)
• Higher general and administrative expense in 2021, mainly due to the receipt of benefits under the CEWS program in 2020	(5.9)
• Other	2.8
Cash from operating activities – 2021	**290.4**

Adjusted Funds Flow [(1)]

The following is a reconciliation of adjusted funds flow to the nearest GAAP measure:

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Cash from operating activities	**97.0**	11.4	**290.4**	27.7
Change in non-cash working capital	**42.9**	15.6	**(12.6)**	5.4
Geological and geophysical expenses	**1.6**	1.7	**5.1**	6.2
Asset retirement obligations settled	**6.9**	0.7	**18.4**	34.9
Provisions and other	–	0.1	**24.0**	4.9
Transaction and reorganization costs	–	–	–	3.0
Adjusted funds flow	**148.4**	29.5	**325.3**	82.1
Adjusted funds flow (*$/Boe*)	**19.63**	5.25	**14.73**	4.50

(1) "Adjusted funds flow" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.

Adjusted funds flow was $148.4 million in the third quarter of 2021 compared to $29.5 million in the third quarter of 2020. Significant factors contributing to the change are shown below:

Three months ended September 30	
Adjusted funds flow – 2020	**29.5**
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	180.3
• Lower interest and financing expense in 2021	8.8
• Payments on financial commodity contract settlements in 2021 compared to receipts in 2020	(68.8)
• Other	(1.4)
Adjusted funds flow – 2021	**148.4**

Adjusted funds flow for the nine months ended September 30, 2021 was $325.3 million compared to $82.1 million for the same period in 2020. Significant factors contributing to the change are shown below:

Nine months ended September 30	
Adjusted funds flow – 2020	**82.1**
• Higher netback in 2021, mainly due to higher commodity prices and sales volumes	426.0
• Payments on financial commodity contract settlements in 2021 compared to receipts in 2020	(175.5)
• Higher general and administrative expense in 2021, mainly due to the receipt of benefits under the CEWS program in 2020	(5.9)
• Other	(1.4)
Adjusted funds flow – 2021	**325.3**

OPERATING RESULTS

Netback [(1)]

	Three months ended September 30				Nine months ended September 30			
	2021		2020		2021		2020	
		($/Boe)[(2)]		($/Boe)[(2)]		($/Boe)[(2)]		($/Boe)[(2)]
Natural gas revenue	96.5	3.89	40.0	1.94	248.6	3.35	138.2	2.05
Condensate and oil revenue	249.9	84.42	88.7	48.74	645.4	77.43	260.5	44.23
Other NGLs revenue	21.7	47.05	6.6	18.10	51.2	37.18	15.3	13.60
Royalty and other revenue	1.0	–	3.5	–	3.5	–	10.0	–
Petroleum and natural gas sales	369.1	48.84	138.8	24.70	948.7	42.96	424.0	23.23
Royalties	(30.9)	(4.09)	(4.3)	(0.77)	(74.5)	(3.37)	(19.6)	(1.07)
Operating expense	(83.3)	(11.02)	(62.4)	(11.10)	(249.4)	(11.29)	(217.3)	(11.90)
Transportation and NGLs processing [(3)]	(30.3)	(4.01)	(27.8)	(4.95)	(88.4)	(4.00)	(76.7)	(4.20)
Netback	224.6	29.72	44.3	7.88	536.4	24.30	110.4	6.06
Commodity contract settlements	(59.0)	(7.81)	9.8	1.75	(145.8)	(6.60)	29.7	1.62
Netback including commodity contract settlements	165.6	21.91	54.1	9.63	390.6	17.70	140.1	7.68

(1) "Netback" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.
(2) Natural gas revenue presented per Mcf.
(3) Includes downstream transportation costs and NGLs fractionation costs.

Petroleum and natural gas sales were $369.1 million in the third quarter of 2021, an increase of $230.3 million from the third quarter of 2020. Petroleum and natural gas sales were $948.7 million for the nine months ended September 30, 2021, an increase of $524.7 million compared to the same period in 2020.

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 Other	Total
Three months ended September 30, 2020	40.0	88.7	6.6	3.5	138.8
Effect of changes in sales volumes	8.2	55.6	1.8	–	65.6
Effect of changes in prices	48.3	105.6	13.3	–	167.2
Change in royalty and other revenue	–	–	–	(2.5)	(2.5)
Three months ended September 30, 2021	**96.5**	**249.9**	**21.7**	**1.0**	**369.1**

	Natural Gas	Condensate and Oil	Other NGLs	Royalty and Other	Total
Nine months ended September 30, 2020	138.2	260.5	15.3	10.0	424.0
Effect of changes in sales volumes	13.9	108.2	3.4	–	125.5
Effect of changes in prices	96.5	276.7	32.5	–	405.7
Change in royalty and other revenue	–	–	–	(6.5)	(6.5)
Nine months ended September 30, 2021	**248.6**	**645.4**	**51.2**	**3.5**	**948.7**

Sales Volumes [(1)]

	Three months ended September 30											
	Natural gas (MMcf/d)			Condensate and oil (Bbl/d)			Other NGLs (Bbl/d)			Total (Boe/d)		
	2021	2020	*% Change*	**2021**	2020	*% Change*	**2021**	2020	*% Change*	**2021**	2020	*% Change*
Grande Prairie	**148.0**	67.3	*120*	**26,648**	13,960	*91*	**3,274**	2,060	*59*	**54,586**	27,237	*100*
Kaybob	**91.3**	113.8	*(20)*	**4,419**	5,142	*(14)*	**1,415**	1,363	*4*	**21,054**	25,477	*(17)*
Central Alberta & Other	**30.4**	42.9	*(29)*	**1,110**	680	*63*	**328**	529	*(38)*	**6,510**	8,350	*(22)*
Total	**269.7**	224.0	*20*	**32,177**	19,782	*63*	**5,017**	3,952	*27*	**82,150**	61,064	*35*

(1) Readers are referred to the Product Type Information section of this document for more information respecting the composition of sales volumes by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

Sales volumes were 82,150 Boe/d (45% liquids) in the third quarter of 2021 compared to 61,064 Boe/d (39% liquids) in the same period in 2020. The Company focused its capital program in 2020 and the first nine months of 2021 on its developments at Karr and Wapiti, which resulted in higher 2021 sales volumes in the liquids rich Grande Prairie Region and lower sales volumes in the Kaybob and Central Alberta & Other Regions due to declines.

At Karr, third quarter 2021 sales volumes were 39,878 Boe/d (52% liquids) compared to 19,246 Boe/d (57% liquids) in the same period in 2020. The increase resulted from development activities where Paramount brought 14 new wells on production in 2021 in addition to 10 new wells brought onstream in the last four months of 2020.

Sales volumes at Wapiti increased to 14,651 Boe/d (62% liquids) in the third quarter of 2021 compared to 7,925 Boe/d (63% liquids) in the third quarter of 2020. The increase mainly resulted from development activities where the Company brought seven wells on production in the third quarter of 2021 in addition to five new wells brought onstream in the fourth quarter of 2020.

Production at Wapiti was impacted by approximately 1,900 Boe/d in the third quarter of 2021 as a result of a scheduled ten-day outage at the third-party Wapiti natural gas processing plant (the "Wapiti Plant"). This outage was undertaken to permanently address the source of the approximate six-week unplanned outage that occurred at the facility in the third quarter of 2020.

Third quarter 2021 sales volumes were also lower by approximately 2,800 Boe/d (16.0 MMcf/d of conventional gas and 147 Bbl/d of NGLs) in the Kaybob Region and approximately 1,900 Boe/d (8.2 MMcf/d of shale gas and 513 Bbl/d of NGLs) in the Central Alberta & Other Region compared to the third quarter of 2020 due to non-core dispositions completed in 2021.

In July 2021, Paramount closed the sale of its non-operated Birch assets in northeast British Columbia (the "Birch Property"), which were included in the Central Alberta & Other Region, for proceeds of approximately $85 million (the "Birch Disposition"). The Birch Property had average sales volumes of approximately 2,300 Boe/d (10.7 MMcf/d of shale gas and 524 Bbl/d of NGLs) and a netback of approximately $3 million in the second quarter of 2021, the last full quarter prior to sale.

In the first quarter of 2021, the Company sold certain properties in the Kaybob and Central Alberta & Other Regions for proceeds of approximately $79 million. These assets had average sales volumes of approximately 2,700 Boe/d (15.4 MMcf/d of conventional natural gas and 142 Bbl/d of NGLs) and a netback of approximately $3 million in the fourth quarter of 2020, the last full quarter prior to sale.

	Nine months ended September 30											
	Natural gas (MMcf/d)			Condensate and oil (Bbl/d)			Other NGLs (Bbl/d)			Total (Boe/d)		
	2021	2020	*% Change*	**2021**	2020	*% Change*	**2021**	2020	*% Change*	**2021**	2020	*% Change*
Grande Prairie	**135.0**	73.4	*84*	**24,914**	14,786	*68*	**3,045**	1,807	*69*	**50,465**	28,824	*75*
Kaybob	**98.8**	128.5	*(23)*	**4,860**	6,058	*(20)*	**1,553**	1,765	*(12)*	**22,879**	29,232	*(22)*
Central Alberta & Other	**38.2**	44.2	*(14)*	**759**	651	*17*	**443**	530	*(16)*	**7,557**	8,565	*(12)*
Total	**272.0**	246.1	*11*	**30,533**	21,495	*42*	**5,041**	4,102	*23*	**80,901**	66,621	*21*

(1) Readers are referred to the Product Type Information section of this document for more information respecting the composition of sales volumes by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

Sales volumes were 80,901 Boe/d (44% liquids) in the nine months ended September 30, 2021 compared to 66,621 Boe/d (38% liquids) in the same period in 2020. The Company focused its capital program in 2020 and the first nine months of 2021 on its developments at Karr and Wapiti, which resulted in higher 2021 sales volumes in the liquids rich Grande Prairie Region and lower sales volumes in the Kaybob and Central Alberta & Other Regions due to declines.

At Karr, sales volumes were 37,286 Boe/d (53% liquids) for the nine months ended September 30, 2021 compared to 18,715 Boe/d (54% liquids) in the same period in 2020. The increase resulted from development activities where Paramount brought 14 new wells on production in 2021 in addition to 10 new wells brought onstream in the last four months of 2020.

Sales volumes at Wapiti increased to 13,122 Boe/d (61% liquids) in the nine months ended September 30, 2021 compared to 10,022 Boe/d (64% liquids) in the same period in 2020. The increase mainly resulted from development activities where the Company brought seven wells on production in the third quarter of 2021 in addition to five new wells brought onstream in the fourth quarter of 2020. Wapiti sales volumes in 2020 were impacted by outages at the Wapiti Plant which amounted to approximately ten weeks of downtime.

For the nine months ended September 30, 2021, sales volumes were also lower by approximately 2,600 Boe/d (14.6 MMcf/d of conventional gas and 131 Bbl/d of NGLs) in the Kaybob Region and approximately 500 Boe/d (2.0 MMcf/d of shale gas and 132 Bbl/d of NGLs) in the Central Alberta & Other Region compared to the same period in 2020 due to non-core dispositions completed in 2021.

Commodity Prices

	Three months ended September 30			Nine months ended September 30		
	2021	2020	% Change	**2021**	2020	% Change
Natural Gas						
Paramount realized price ($/Mcf)	**3.89**	1.94	*101*	**3.35**	2.05	*63*
AECO daily spot ($/GJ)	**3.41**	2.12	*61*	**3.11**	1.98	*57*
AECO monthly index ($/GJ)	**3.36**	2.04	*65*	**2.94**	1.96	*50*
Dawn ($/MMbtu)	**5.18**	2.44	*112*	**4.12**	2.36	*75*
NYMEX (US$/MMbtu)	**4.32**	2.13	*103*	**3.34**	1.92	*74*
Malin – monthly index (US$/MMbtu)	**4.12**	1.90	*117*	**3.19**	1.90	*68*
Condensate and Oil						
Paramount realized condensate & oil price ($/Bbl)	**84.42**	48.74	*73*	**77.43**	44.23	*75*
Edmonton light sweet crude oil ($/Bbl)	**84.18**	49.05	*72*	**76.37**	44.13	*73*
West Texas Intermediate (US$/Bbl)	**70.56**	40.93	*72*	**64.82**	38.32	*69*
Other NGLs (1)						
Paramount realized Other NGLs price ($/Bbl)	**47.05**	18.10	*160*	**37.18**	13.60	*173*
Conway – propane ($/Bbl)	**61.80**	26.02	*138*	**51.18**	23.00	*123*
Belvieu – butane ($/Bbl)	**70.48**	30.23	*133*	**56.38**	28.61	*97*
Foreign Exchange						
$CDN / 1 $US	**1.26**	1.33	*(5)*	**1.25**	1.35	*(7)*

(1) "Other NGLs" refers to ethane, propane and butane combined. Readers are referred to the Product Type Information section of this document.

Paramount's natural gas portfolio primarily consists of sales priced at Alberta, British Columbia, California, Chicago, Ventura and Eastern Canada markets, which are sold in a combination of daily, monthly, seasonal and fixed-priced physical contracts. The Company's natural gas portfolio includes arrangements to sell approximately 60,000 GJ/d of natural gas at Dawn, approximately 22,000 GJ/d of natural gas at Malin and 40,000 GJ/d of natural gas sales priced at the US Midwest.

The Company had the following fixed-price physical sales contracts in place at September 30, 2021:

	Location	Average fixed price	Remaining term
Natural gas – 50,000 GJ/d	AECO	CDN$2.52/GJ	October 2021
Natural gas – 100,000 GJ/d	AECO	CDN$3.27/GJ	October 2021 - December 2021
Natural gas – 40,000 GJ/d	AECO	CDN$4.06/GJ	January 2022 - March 2022

Subsequent to September 30, 2021, the Company entered into the following fixed-price physical sales contracts:

	Location	Average fixed price	Remaining term
Natural gas – 30,000 GJ/d	AECO	CDN$3.54/GJ	April 2022 – October 2022
Condensate – 2,538 Bbl/d	FSPL (1)	WTI + US$3.15/Bbl	December 2021
Condensate – 2,098 Bbl/d	FSPL (1)	WTI + US$3.13/Bbl	January 2022 – March 2022

(1) FSPL refers to refers to condensate delivered into the Fort Saskatchewan Pipeline at Edmonton.

Paramount ships a majority of its condensate and crude oil production on third-party pipelines for sale in Edmonton, Alberta, where volumes generally receive higher prices due to the greater diversity of potential purchasers. A minimal portion of the Company's production is sold at the lease when warranted by economic or operational factors. Sales prices for condensate and crude oil are based on West Texas Intermediate reference prices, adjusted for transportation, quality and density differentials.

The Company's butane and propane volumes are generally sold under contracts that are renewed annually in April each year. The Company's propane and butane contracts in place in the first nine months of 2021 had more favorable differentials to West Texas Intermediate reference prices than in the same period in 2020.

Financial Commodity Contracts

From time-to-time Paramount enters into financial commodity contracts to manage exposure to commodity price volatility. Changes in the fair value of the Company's financial commodity contracts are as follows:

	Nine months ended September 30, 2021	Twelve months ended December 31, 2020
Fair value, beginning of period	**(22.7)**	6.1
Changes in fair value	**(203.8)**	8.8
Settlements paid (received)	**145.8**	(37.6)
Fair value, end of period	**(80.7)**	(22.7)

For further details on the Company's financial commodity contracts, refer to Note 12 of the Interim Financial Statements.

Subsequent to September 30, 2021, the Company entered into the following financial commodity contracts:

Instruments	Aggregate notional	Average fixed price	Remaining term
Oil – NYMEX WTI Swaps (Sale)	3,500 Bbl/d	CDN$91.38/Bbl	January 2022 – December 2022
Oil – NYMEX WTI Swaps (Sale)	3,500 Bbl/d	US$75.79/Bbl	January 2022 – December 2022
Oil – NYMEX WTI Costless Collars	7,000 Bbl/d	CDN$82.50/Bbl (Floor) CDN$100.47/Bbl (Ceiling)	January 2022 – December 2022

The following table summarizes the Company's financial commodity contracts and fixed-price physical contracts at November 3, 2021:

	Type (1)	Q4 2021	Q1 2022	Q2 2022	Q3 2022	Q4 2022	Average Price (2)
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	10,000	–	–	–	–	US$45.82/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	–	3,500	3,500	3,500	3,500	US$75.79/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	6,000	–	–	–	–	CDN$88.45/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	–	9,500	–	–	–	CDN$87.90/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	–	–	3,500	3,500	3,500	CDN$91.38/Bbl
Oil – WTI Costless Collars (Bbl/d)	Financial	–	7,000	7,000	7,000	7,000	CDN$82.50/Bbl (Floor) CDN$100.47/Bbl (Ceiling)
Condensate – Basis (Sale) (Bbl/d)	Physical	855	2,098	–	–	–	WTI + US$3.13/Bbl
Gas – NYMEX Swaps (Sale) (MMbtu/d)	Financial	110,000	–	–	–	–	US$3.37/MMbtu
Gas – NYMEX Swaps (Sale) (MMbtu/d)	Financial	–	40,000	–	–	–	US$4.15/MMbtu
Gas – AECO fixed price (GJ/d)	Physical	116,848	–	–	–	–	CDN$3.16/GJ
Gas – AECO fixed price (GJ/d)	Physical	–	40,000	–	–	–	CDN$4.06/GJ
Gas – AECO fixed price (GJ/d)	Physical	–	–	30,000	30,000	10,109	CDN$3.54/GJ

(1) Financial, refers to financial commodity contracts. Physical, refers to fixed-priced and basis physical contracts.
(2) Average price is calculated using a weighted average of notional volumes and prices.

Royalties

	Three months ended September 30				Nine months ended September 30			
	2021	Rate	2020	Rate	2021	Rate	2020	Rate
Royalties	30.9	8.4%	4.3	3.2%	74.5	7.9%	19.6	4.7%
$/Boe	*4.09*		*0.77*		*3.37*		*1.07*	

Royalties were $30.9 million in the third quarter of 2021, compared to $4.3 million in the same period in 2020. Royalties for the nine months ended September 30, 2021 were $74.5 million compared to $19.6 million in the first nine months of 2020. Royalties increased in the three and nine months ended September 30, 2021 primarily as a result of higher commodity prices and increased sales volumes.

Operating Expense

	Three months ended September 30			Nine months ended September 30		
	2021	2020	% Change	2021	2020	% Change
Operating expense	83.3	62.4	*33*	249.4	217.3	*15*
$/Boe	*11.02*	*11.10*	*(1)*	*11.29*	*11.90*	*(5)*

Operating expenses were $83.3 million, or $11.02 per Boe, in the third quarter of 2021 compared to $62.4 million, or $11.10 per Boe, in the same period in 2020. Operating expenses were $249.4 million, or $11.29 per Boe, in the first nine months of 2021 compared to $217.3 million, or $11.90 per Boe, in the same period in 2020.

Operating costs in the third quarter of 2021 were higher compared to the same period in 2020, primarily as a result of higher production and processing fees in the Grande Prairie Region in 2021, increased maintenance activities, higher electricity prices and the receipt in 2020 of benefits under the CEWS program. These increases were partially offset by lower operating costs because of lower production in the Kaybob and Central Alberta & Other Regions.

Operating expenses for the nine months ended September 30, 2021 were higher than the same period in 2020, mainly due to higher production and processing fees in the Grande Prairie Region in 2021, supplier cost reductions unique to the second quarter of 2020 and equalizations related to prior periods that reduced operating costs in 2020. These increases were partially offset by lower operating costs because of lower production in the Kaybob and Central Alberta & Other Regions and cost reductions from water disposal wells brought into service in the first half of 2020.

Transportation and NGLs Processing

	Three months ended September 30			Nine months ended September 30		
	2021	2020	% Change	2021	2020	% Change
Transportation and NGLs processing	30.3	27.8	9	88.4	76.7	15
$/Boe	*4.01*	*4.95*	*(19)*	*4.00*	*4.20*	*(5)*

Transportation and NGLs processing was $30.3 million and $88.4 million for the three and nine months ended September 30, 2021, respectively, compared to $27.8 million and $76.7 million for the corresponding periods in 2020. Transportation and NGLs processing costs increased in 2021 mainly as a result of higher contracted transportation capacity for Karr.

Other Operating Items

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Depletion and depreciation (excluding impairment / reversal)	(75.0)	(54.6)	(220.1)	(189.1)
Change in asset retirement obligations	2.2	25.6	(109.3)	121.0
(Impairment) of petroleum and natural gas assets / reversal	282.6	–	296.6	(191.8)
Gain (loss) on sale of oil and gas assets	32.3	(8.0)	72.1	(8.7)
Exploration and evaluation expense	(6.7)	(1.7)	(29.7)	(25.2)

Depletion and depreciation expense increased to $75.0 million in the third quarter of 2021 compared to $54.6 million in the same period of 2020. Depletion and depreciation expense increased to $220.1 million in the nine months ended September 30, 2021 compared to $189.1 million in the same period in 2020. The increase in depletion and depreciation expense in 2021 was mainly attributable to the impact of higher sales volumes, which was partially offset by lower depletion rates in the Grande Prairie Region.

For the nine months ended September 30, 2021, the Company recorded a charge of $109.3 million (nine months ended September 30, 2020 – a recovery of $121.0 million) to earnings mainly 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 property, plant and equipment. The changes mainly resulted from a revision in the credit-adjusted risk-free rate used to discount these obligations.

At September 30, 2021, the Company recorded an aggregate of $282.6 million in reversals of previously recorded impairment charges to petroleum and natural gas assets, comprised of $270.3 million related to the Kaybob cash-generating unit ("CGU") and $12.3 million related to the Northern CGU. The impairment reversals resulted from an increase in the estimated recoverable amount of such CGUs compared to the prior impairment assessment performed at December 31, 2020.

The $282.6 million in aggregate impairment reversals represent the amount to bring the carrying values of the Kaybob and Northern CGUs to the amounts, net of depletion and amortization, had no impairment charges been recognized in prior periods. The increase in the estimated recoverable amount of these CGUs was mainly due to higher and sustained forecasted condensate, crude oil and natural gas prices and the increase in the Company's market capitalization since the prior impairment assessment performed at December 31, 2020.

The recoverable amount of the Kaybob and Northern CGUs as at September 30, 2021 was estimated on a fair value less costs of disposal basis, using a discounted cash flow method (level 3 fair value hierarchy estimate). Cash flows were projected over the expected remaining productive life of the proved plus probable reserves assigned to the Kaybob and Northern CGUs, at discount rates of 11.0 percent and 13.0 percent, respectively. The net cash flows from the proved plus probable reserves estimated by Paramount's independent qualified reserves evaluator as at December 31, 2020 were mechanically updated by Management to October 1, 2021, including to reflect commodity price estimates at October 1, 2021. The reserves evaluation process is inherently subjective and involves considerable estimation uncertainty.

The following table sets out the forecast benchmark commodity prices and exchange rates used to determine estimated recoverable amounts at October 1, 2021[1]:

(Average for the period)	(Oct-Dec) 2021	2022	2023	2024	2025	2026-2035	Thereafter
Natural Gas [2]							
AECO ($/MMBtu)	4.57	3.83	3.26	2.99	3.05	3.12 – 3.72	+2%/yr
Henry Hub (US$/MMBtu)	5.40	4.25	3.44	3.17	3.24	3.30 – 3.95	+2%/yr
Crude Oil and Condensate [2]							
Edmonton Condensate ($/Bbl)	94.79	88.36	83.33	80.56	82.16	83.81 – 100.16	+2%/yr
WTI (US$/Bbl)	75.17	71.00	67.77	65.57	66.88	68.22 – 81.52	+2%/yr
Foreign Exchange							
$US / 1 $CDN	0.795	0.798	0.80	0.80	0.80	0.80	0.80

(1) Average of forecasts published by: (i) McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. at October 1, 2021 and (ii) Sproule Associates Ltd. at September 30, 2021.
(2) Forecast benchmark prices are adjusted for quality differentials, heat content, distance to market and other factors in determining estimated recoverable amounts.

At March 31, 2020, the Company recorded impairments of $188.3 million and $3.5 million related to petroleum and natural gas assets in the Kaybob and Northern CGUs, respectively. At December 31, 2020, the Company recorded aggregate impairment reversals of $333.7 million from previously recorded impairment charges, comprised of $287.7 million, $30.6 million and $15.4 million related to petroleum and natural gas assets in the Kaybob, Northern and Central Alberta CGUs, respectively. For additional information on impairments and impairment reversals in 2020, refer to Note 5 of the Annual Financial Statements.

The Birch Property, which was included in the Northern CGU, was reclassified as held for sale as at June 30, 2021. As the consideration received on the Birch Disposition exceeded the carrying value of the asset, which had previously been reduced by impairment charges, a reversal of previously recorded impairment charges of $14.1 million was recorded for the three months ended June 30, 2021. This reversal represented the amount required to increase the carrying value of the Birch assets to the amount that would have been determined, net of depletion and amortization, had no impairment charges been recognized in prior periods. A gain of $36 million was recognized on the sale for the three months ended September 30, 2021.

A gain of $39.4 million was recognized on the sale of certain properties in the Kaybob and Central Alberta CGUs in the first quarter of 2021.

Exploration and evaluation expense was $6.7 million and $29.7 million for the three and nine months ended September 30, 2021, respectively, compared to $1.7 million and $25.2 million for the corresponding periods in 2020. The increase in 2021 was primarily due to higher expenses for expired mineral leases.

INVESTMENTS IN SECURITIES

As at	September 30, 2021	December 31, 2020
Level one fair value hierarchy securities ("Level One Securities")	231.0	48.4
Level three fair value hierarchy securities ("Level Three Securities")	71.9	11.1
	302.9	59.5

Paramount holds investments in a number of publicly-traded and private corporations as part of its portfolio of investments. Investments that are categorized as Level One Securities are carried at their period-end trading prices. Estimates of fair values for investments that are categorized as Level Three 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 including financial and operating results of the entities. Fair value estimates of Level Three 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.

For the three and nine months ended September 30, 2021, the Company recorded $74.7 million and $242.4 million, respectively, to other comprehensive income ("OCI") as a result of changes in the fair value estimates of investments in securities.

Changes in the fair value of investments in securities are as follows:

	Nine months ended September 30, 2021	Twelve months ended December 31, 2020
Investments in securities, beginning of period	59.5	156.9
Changes in fair value of Level One Securities – recorded in OCI	181.6	(50.6)
Changes in fair value of Level Three Securities – recorded in OCI	60.8	32.5
Transfer to dissent payment entitlement	–	(89.3)
Derecognition of Strathcona warrants	(0.1)	–
Changes in fair value of Strathcona warrants – recorded in earnings	0.1	(1.7)
Additions	1.0	11.7
Investments in securities, end of period	302.9	59.5

ASSET RETIREMENT OBLIGATIONS

The Alberta Energy Regulator's area-based closure program allows companies to approach abandonment and reclamation activities in an efficient and cost-effective manner by targeting efforts in a concentrated area. Paramount's strategy is to utilize the advantages of the area-based closure program by focusing its abandonment and reclamation activities on the Hawkeye property, which was shut-in in 2018, and the Zama property, which was shut-in in 2019.

Abandonment and reclamation expenditures in the nine months ending September 30, 2021 totaled $18.4 million, net of approximately $3.4 million in funding under the ASRP. Activities in the first nine months of 2021 included the abandonment of 151 wells, 129 of which were abandoned under the Company's ongoing area-based closure program at Zama.

The Company's budget for abandonment and reclamation activities in 2021 remains unchanged at approximately $31 million. Approximately $6 million is to be funded directly under the ASRP, resulting in approximately $25 million net to Paramount. The majority of 2021 activities will be performed at Zama.

As at September 30, 2021, estimated undiscounted, uninflated asset retirement obligations were $1,287.2 million (December 31, 2020 – $1,351.7 million). As at September 30, 2021, the Company's discounted asset retirement obligations were $628.5 million (discounted at 7.0% and using an inflation rate of 2.0%) compared to $419.5 million as at December 31, 2020 (discounted at 11.0% and using an inflation rate of 2.0%). For further details concerning the Company's asset retirement obligations, refer to the Interim Financial Statements.

CORPORATE

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
General and administrative	(10.4)	(7.8)	(29.7)	(23.7)
Share-based compensation	(3.0)	(5.6)	(11.1)	(6.2)
Interest and financing	(8.7)	(17.1)	(38.0)	(35.9)
Accretion of asset retirement obligations	(10.6)	(11.0)	(32.1)	(32.1)
Loss on dissent payment entitlement	–	–	(22.6)	–
Deferred income tax (expense) recovery	(89.1)	18.5	(49.0)	(74.6)

General and administrative expenses were higher for the three and nine months ended September 30, 2021 compared to the same periods in 2020 mainly due to the impact in 2020 of benefits received under the CEWS program, which totaled $1.8 million and $5.5 million for the three and nine months ended September 30, 2020, respectively.

Share-based compensation expense was higher for the nine months ended September 30, 2021 mainly due to the reinstatement of incentive compensation programs that had been suspended in the first half of 2020.

Interest and financing expenses were lower in the third quarter of 2021 compared to the same period in 2020 mainly as a result of lower interest rates under the Company's financial covenant-based senior secured revolving bank credit facility (the "Paramount Facility") and lower average debt balances.

Paramount held 85 million common shares of Strath Resources Ltd. ("Strath") prior to its amalgamation with Cona Resources Ltd. in August 2020 to form Strathcona Resources Ltd. ("Strathcona"). Paramount objected to the amalgamation and exercised its right of dissent under section 191 of the *Business Corporations Act* (Alberta) with respect to its Strath shares. As a result, the Company was entitled to be paid in cash the fair value of its Strath shares, determined as of the close of business on July 24, 2020. In June 2021, Paramount received $67 million cash in settlement of the dissent proceedings and for the sale of its remaining securities in Strathcona. A loss of $22.6 million was recognized on the settlement.

TOTAL CAPITAL EXPENDITURES (1)

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Drilling, completion and tie-ins	64.1	44.8	200.3	135.3
Facilities and gathering	0.4	4.2	4.0	15.7
Corporate	1.6	1.5	4.6	4.2
Land and property acquisitions	2.8	–	2.8	0.6
Total capital expenditures	68.9	50.5	211.7	155.8
Grande Prairie Region	53.1	46.1	170.8	132.6
Kaybob Region	1.7	2.7	10.7	14.6
Central Alberta & Other Region	9.7	0.2	22.8	3.8
Corporate	1.6	1.5	4.6	4.2
Land and property acquisitions	2.8	–	2.8	0.6
Total capital expenditures	68.9	50.5	211.7	155.8

(1) "Total Capital Expenditures" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.

Total capital expenditures were $68.9 million in the third quarter of 2021 compared to $50.5 million in the third quarter of 2020. Total capital expenditures were $211.7 million for the nine months ended September 30, 2021 compared to $155.8 million in the same period in 2020. Expenditures in the first nine months of 2021 were mainly directed to drilling and completion programs in the Grande Prairie Region. Significant capital program activities undertaken in the nine months ended September 30, 2021 are described below:

- At Karr, the Company drilled 16 (16.0 net) wells, commenced drilling operations on 4 (4.0 net) wells, commenced completion operations on 5 (5.0 net) wells and completed and brought on production 14 (14.0 net) wells.

- At Wapiti, Paramount drilled 11 (11.0 net) wells, commenced drilling operations on 1 (1.0 net) well, and completed and brought on production 7 (7.0 net) wells.

- In the Kaybob Region, the Company completed and brought on production 1 (1.0 net) oil well at Ante Creek.

- In the Central Alberta & Other region, Paramount drilled, completed and brought on production 2 (2.0 net) wells at Willesden Green.

LIQUIDITY AND CAPITAL RESOURCES

Paramount's primary objectives in managing its capital structure are to:

i. maintain a flexible capital structure which optimizes the cost of capital at an acceptable level of risk;

ii. maintain sufficient liquidity to support ongoing operations, capital expenditure programs, regular monthly dividends and other planned shareholder returns, strategic initiatives and the settlement of obligations when due; and

iii. maximize shareholder returns.

As described under "Free Cash Flow Priorities", Paramount is targeting a long-term leverage level of approximately $300 million in net debt.

Paramount manages its capital structure to support current and long-term 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, 2021	December 31, 2020
Cash and cash equivalents	(1.4)	(4.6)
Accounts receivable (1)	(140.1)	(97.7)
Prepaid expenses and other	(13.8)	(9.9)
Accounts payable and accrued liabilities	209.7	152.8
Adjusted working capital deficit (1) (2)	54.4	40.6
Long-term debt	522.4	813.5
Net debt (2)	576.8	854.1
Share capital	2,208.7	2,207.4
Accumulated deficit	(97.8)	(235.1)
Equity component of convertible debentures	1.7	–
Reserves	298.5	65.4
Total Capital	2,987.9	2,891.8

(1) Adjusted working capital excludes risk management assets and liabilities, accounts receivable relating to subleases (September 30, 2021 – $2.4 million, December 31, 2020 – $2.3 million) and the current portion of asset retirement obligations and other.
(2) "Net Debt" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.

Paramount's operations are capital intensive and adequate sources of liquidity are required to fund ongoing exploration and development activities, discharge asset retirement obligations and satisfy contractual commitments. Paramount's available capital resources include cash from operating activities and available capacity under the Paramount Facility, the terms of which are described further below.

Based on the forecasts of 2021 and 2022 sales volumes and the pricing and other assumptions set out in this MD&A under "Q3 2021 Overview" and "2022 Budget and Guidance", Paramount expects to fully fund budgeted fourth quarter 2021 and 2022 capital expenditures with cash from operating activities. Paramount may utilize borrowing capacity under the Paramount Facility for liquidity from time to time to temporarily fund operations during periods of the year in which expenditures exceed cash from operating activities.

The ability of cash from operating activities to satisfy the Company's funding requirements in the fourth quarter of 2021, 2022 and future years is dependent on a number of factors, including commodity prices, sales volumes, royalties, operating and transportation costs, general and administrative and interest expenses and foreign exchange rates.

Paramount may also determine to divest of assets or investments in securities from time to time to reduce indebtedness, fund operations or provide incremental shareholder returns. In the first nine months of 2021, the Company sold non-core properties for aggregate proceeds of approximately $166 million and received $67 million cash in settlement of the Strath dissent proceedings and for the sale of its remaining securities in Strathcona, which proceeds were used to reduce indebtedness under the Paramount Facility.

Subject to market conditions and availability, proceeds from new debt and/or equity financings may also provide additional sources of capital from time to time. In January 2021, as described below under "Convertible Debentures", the Company issued $35.0 million of senior unsecured convertible debentures and used the proceeds to reduce indebtedness under the Paramount Facility.

Paramount Facility

In June 2021, the Company renewed its financial covenant-based senior secured revolving bank credit facility.

The Paramount Facility currently has a credit limit of $900 million, which can be increased to $1.0 billion at Paramount's request pursuant to an accordion feature in the facility, subject to incremental lender commitments. The maturity date of the Paramount Facility is June 2, 2024. The Paramount Facility is secured by a charge over substantially all of the assets of the Company and its subsidiaries.

Borrowings under the Paramount Facility bear interest at the prime lending rate, US base rate, CDOR, or LIBOR, as selected by the Company, plus an applicable margin which varies based on the Company's Senior Secured Debt to Consolidated EBITDA ratio.

Paramount is subject to the following two financial covenants under the Paramount Facility which are tested at the end of each fiscal quarter and calculated on a trailing twelve-month basis:

- Senior Secured Debt to Consolidated EBITDA to be 3.50 to 1.00 or less; and
- Consolidated EBITDA to Consolidated Interest Expense to be 2.50 to 1.00 or greater.

Senior Secured Debt currently consists of amounts drawn on the Paramount Facility.

Consolidated EBITDA is adjusted for material acquisitions and dispositions and is generally calculated as net income before Consolidated Interest Expense, taxes, depletion, depreciation, amortization, impairment and exploration and evaluation expense and is also adjusted to exclude non-recurring items and other non-cash items including gains or losses on dispositions of oil and gas assets, unrealized mark-to-market amounts on derivatives, unrealized foreign exchange gains and losses, share-based compensation expense and accretion.

Consolidated Interest Expense is reduced by customary adjustments including interest income.

The Paramount Facility contains a covenant requiring prior lender consent for the payment of dividends and other distributions if the Senior Secured Debt to Consolidated EBITDA ratio is greater than 2.50 to 1.00 *pro forma* the payment of the distribution.

Paramount was in compliance with the financial covenants under the Paramount Facility at September 30, 2021.

The Company had undrawn letters of credit outstanding under the Paramount Facility totaling $2.3 million at September 30, 2021 that reduce the amount available to be drawn on the facility.

Unsecured Letter of Credit Facility

The Company has a $70 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 ("PSG") from Export Development Canada. In May 2021, the PSG was extended to June 30, 2022.

At September 30, 2021, $42.6 million in undrawn letters of credit were outstanding under the LC Facility (December 31, 2020 – $40.7 million).

Convertible Debentures

In January 2021, the Company completed a private placement of $35.0 million of senior unsecured convertible debentures (the "Convertible Debentures"). An entity controlled by Paramount's President and Chief Executive Officer and Chairman purchased $25.0 million of the Convertible Debentures. The Convertible Debentures mature on January 31, 2024 (the "Maturity Date"), bear interest at 7.50 percent per annum payable monthly in arrears and are convertible by the holder into Common Shares at any time prior to the Maturity Date. At September 30, 2021, the conversion price of the debentures was $6.69 per Common Share if converted prior to January 31, 2022, $7.30 per Common Share if converted on or after January 31, 2022 and prior to January 31, 2023 and $7.91 per Common Share if converted on or after January 31, 2023. These prices are subject to customary anti-dilution adjustments.

The Convertible Debentures are redeemable by Paramount, in whole or in part, at any time prior to the Maturity Date, at a redemption price (expressed as percentages of principal amount) equal to 107.50 percent prior to January 31, 2022, 103.75 percent on or after January 31, 2022 and prior to January 31, 2023 and 101.875 percent on or after January 31, 2023.

The Convertible Debentures are treated as a compound financial instrument that contain a liability and an equity component and were initially recognized at fair value, net of issue costs of $0.1 million. The fair value of the liability component was initially recognized at the date of issuance using the effective interest method, discounted using the estimated interest rate of a debt instrument having similar terms but without a conversion feature. The fair value of the conversion feature was determined at the date of issuance as the difference between the principal amount and the fair value of the liability component at the date of issue, which has been classified within shareholders' equity.

The liability component of the Convertible Debentures is carried at amortized cost and is accreted over the term of the Convertible Debentures to the principal amount using the effective interest method. This accretion, along with interest on the Convertible Debentures, is recorded as interest and financing expense. The equity component is not remeasured subsequent to initial recognition. The equity component and the accreted liability component will be reclassified to share capital should the Convertible Debentures be converted into Common Shares.

As at September 30, 2021, there were $35.0 million aggregate principal amount of Convertible Debentures outstanding.

In November 2021, the Company delivered notices to redeem all $35 million of the Convertible Debentures, effective December 3, 2021. It is expected that all holders will exercise their right to convert their debentures into Common Shares prior to the redemption date, resulting in approximately 5.3 million Common Shares being issued.

Cash Flow Hedges

The Company had the following floating-to-fixed interest rate and electricity swaps in place at September 30, 2021:

Contract type	Aggregate notional	Remaining term	Average fixed contract rate	Reference	Fair value
Interest Rate Swaps	$250 million	October 2021 - January 2023	2.3%	CDOR (1)	(5.2)
Interest Rate Swaps	$250 million	October 2021 - January 2026	2.4%	CDOR (1)	(10.1)
Electricity Swaps	5 MWh/d (2)	October 2021 - December 2021	$51.68/MWh	AESO Pool Price (3)	0.5
Electricity Swaps	5 MWh/d (2)	January 2023 - December 2023	$62.50/MWh	AESO Pool Price (3)	0.2
Electricity Swaps	5 MWh/d (2)	January 2024 - December 2024	$53.25/MWh	AESO Pool Price (3)	0.2
					(14.4)

(1) Canadian Dollar Offered Rate.
(2) "MWh" means MegaWatt per hour for the remaining term.
(3) Floating hourly rate established by the Alberta Electric System Operator.

The Company has classified these arrangements as cash flow hedges and applied hedge accounting. At September 30, 2021, $20 million of floating-to-fixed interest rate swaps were de-designated as cash flow hedges due to declines in borrowings under the Paramount Facility. There were no other changes to the critical terms of the hedging relationships and no hedge ineffectiveness was identified on the floating-to-fixed electricity swaps.

In the third quarter of 2021, Paramount entered into floating-to-fixed price swaps to manage exposure to the variable market price of electricity by fixing the underlying AESO Pool Price on a portion of the Company's anticipated power requirements for 2023 and 2024.

Share Capital

As at November 1, 2021, Paramount had 133,456,272 Common Shares outstanding (net of 1,536,075 Common Shares held in trust under the Company's restricted share unit plan) and 11,592,199 options to acquire Common Shares outstanding, of which 3,224,755 options are exercisable.

As at November 1, 2021, $35.0 million aggregate principal amount of Convertible Debentures were issued and outstanding and 5.2 million Common Shares were issuable upon conversion of the outstanding Convertible Debentures at the current conversion price of $6.69 per Common Share.

Dividends and NCIB

In June 2021, Paramount announced the implementation of a monthly dividend program with respect to its Common Shares. Dividends declared in the nine months ended September 30, 2021 totaled $0.06 per share.

On October 29, 2021, the Company paid a dividend of $0.02 per Common Share to the shareholders of record on October 15, 2021.

Paramount's Board of Directors has approved an increase in the Company's regular monthly dividend from $0.02 to $0.06 per Common Share. The first increased dividend will be payable on November 30, 2021 to shareholders of record on November 15, 2021.

In June 2021, Paramount implemented the NCIB. Paramount may purchase up to 7,308,743 Common Shares under the NCIB. Any Common Shares purchased pursuant to the NCIB will be cancelled by the Company. The NCIB will terminate on the earlier of June 29, 2022 and the date on which the maximum number of Common Shares that can be acquired pursuant to the NCIB are purchased. Purchases of Common Shares under the NCIB will be effected through the facilities of the TSX or alternative Canadian trading systems at the market price at the time of purchase. To date in 2021, the Company repurchased and cancelled 197,500 Common Shares under the NCIB at a total cost of $2.7 million.

QUARTERLY INFORMATION

	2021			2020				2019
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Petroleum and natural gas sales	**369.1**	299.7	279.9	202.0	138.8	113.2	172.1	259.9
Net income (loss)	**292.7**	(74.3)	(82.5)	311.5	(23.3)	(75.7)	(235.1)	(31.1)
Per share – basic ($/share)	***2.20***	*(0.56)*	*(0.62)*	*2.35*	*(0.17)*	*(0.57)*	*(1.76)*	*(0.24)*
Per share – diluted ($/share)	***2.06***	*(0.56)*	*(0.62)*	*2.35*	*(0.17)*	*(0.57)*	*(1.76)*	*(0.24)*
Cash from (used in) operating activities	**97.0**	112.1	81.3	53.2	11.4	(14.2)	30.5	70.5
Per share – basic ($/share)	***0.73***	*0.84*	*0.61*	*0.40*	*0.09*	*(0.11)*	*0.23*	*0.54*
Per share – diluted ($/share)	***0.68***	*0.84*	*0.61*	*0.40*	*0.09*	*(0.11)*	*0.23*	*0.54*
Adjusted funds flow	**146.4**	86.0	90.9	67.9	29.5	19.0	33.5	93.5
Per share – basic ($/share)	***1.12***	*0.65*	*0.69*	*0.51*	*0.22*	*0.14*	*0.25*	*0.71*
Per share – diluted ($/share)	***1.04***	*0.65*	*0.69*	*0.51*	*0.22*	*0.14*	*0.25*	*0.71*
Dividends declared ($/share)	**0.06**	–	–	–	–	–	–	–
Sales volumes (1)								
Natural gas (MMcf/d)	**269.7**	273.1	273.1	256.3	224.0	253.2	261.5	299.0
Condensate and oil (Bbl/d)	**32,177**	29,543	29,854	25,752	19,782	22,823	21,898	28,516
Other NGLs (Bbl/d)	**5,017**	4,938	5,170	4,987	3,952	3,817	4,539	7,064
Total (Boe/d)	**82,150**	79,995	80,540	73,460	61,064	68,839	70,022	85,411
Liquids %	***45%***	*43%*	*43%*	*42%*	*39%*	*39%*	*38%*	*42%*
Realized prices								
Natural gas ($/Mcf)	**3.89**	3.01	3.14	2.83	1.94	1.94	2.25	2.73
Condensate and oil ($/Bbl)	**84.42**	77.96	69.20	52.03	48.74	29.05	55.92	66.70
Other NGLs ($/Bbl)	**47.05**	32.11	32.29	20.61	18.10	12.28	10.75	13.03
Total ($/Boe)	**48.84**	41.17	38.61	29.89	24.70	18.07	27.01	33.08

(1) Readers are referred to the Product Type Information section of this document for more information respecting the composition of sales volumes by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

Significant Items Impacting Quarterly Results

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

- Third quarter 2021 earnings include aggregate impairment reversals of $282.6 million from previously recorded impairment charges of petroleum and natural gas assets and a $32.3 million gain on the sale of oil and gas assets, partially offset by a $47.0 million loss on financial commodity contracts.
- The second quarter 2021 loss includes a $75.7 million loss on financial commodity contracts and a charge of $42.0 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value.
- The first quarter 2021 loss includes an $81.2 million loss on financial commodity contracts, a charge of $69.5 million mainly related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value and a $41.4 million gain on the sale of oil and gas assets.
- Fourth quarter 2020 earnings include aggregate impairment reversals of $333.7 million from previously recorded impairment charges of petroleum and natural gas assets and a deferred income tax recovery

of $64.4 million, partially offset by a charge of $29.7 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value.

- The third quarter 2020 loss includes a recovery of $25.6 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value.
- The second quarter 2020 loss includes a recovery of $13.6 million related to deferred income tax.
- The first quarter 2020 loss includes a $191.8 million impairment of petroleum and natural gas assets, and a derecognition of $130.0 million of the deferred income tax asset, partially offset by a recovery of $94.8 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 property, plant and equipment.
- The fourth quarter 2019 loss includes a recovery of $33.8 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 property, plant and equipment.

OTHER INFORMATION

Provisions

For the nine months ended September 30, 2021, the Company recorded provisions of $24.0 million with respect to arrangements with a service provider. The Company has unsettled claims of a greater amount against the same service provider with respect to certain related matters which have not been recognized. The outcome of all of these matters remains uncertain.

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.

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.

ADOPTION OF ACCOUNTING STANDARDS

Financial Instruments

Effective January 1, 2021, the Company adopted the phase two amendments to IFRS 9 – *Financial Instruments,* IAS 39 – *Financial Instruments: Recognition and Measurement*, IFRS 7 – *Financial Instruments: Disclosures,* IFRS 4 – *Insurance Contracts* and IFRS 16 – *Leases*. These amendments provide guidance in applying IFRS when there are changes to contractual cash flows or hedging relationships arising from the replacement of an interest rate benchmark with an alternative benchmark rate pursuant to the Interbank Offered Rate ("IBOR") reform. There has been no impact on the recognized assets, liabilities or comprehensive income (loss) of the Company resulting from the adoption of these amendments. The Company's floating-to-fixed interest rate swaps, which are described in Note 12 of the

Interim Financial Statements, may be impacted by these amendments in the future as hedge accounting is applied to these instruments and hedging relationships may be impacted by the IBOR reform.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

During the three months ended September 30, 2021, 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. Paramount does not believe that process changes put in place in connection with the COVID-19 pandemic have materially affected 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.

RISK FACTORS

Readers should, in conjunction with their review of this MD&A, carefully review the "Risk Factors" section in the Company's Annual Information Form for the year ended December 31, 2020, which is available under the Company's profile on SEDAR at www.sedar.com.

The course of the COVID-19 pandemic and its impacts remain highly uncertain. The impacts of the pandemic on Paramount's future operations and financial performance are unknown and are dependent on a number of unpredictable factors outside of the knowledge and control of Management, including: (i) the duration and severity of the pandemic; (ii) the impact of the pandemic on economic growth, inflation, supply chains, commodity prices and financial and capital markets; and (iii) governmental responses and restrictions. These uncertainties may continue to persist beyond the point where the outbreak of the COVID-19 virus has subsided. See "Risk Factors – COVID 19 Pandemic" in the Annual Information Form.

CRITICAL ACCOUNTING ESTIMATES

The timely preparation of financial statements requires Management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosures regarding contingent assets and liabilities. Estimates and assumptions are regularly evaluated and are based on Management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Changes in judgments, estimates and assumptions based on new information could result in a material change to the carrying amount of assets or liabilities and have a material impact on assets, liabilities, revenues and expenses recognized in future periods.

The potential impacts of the COVID-19 pandemic have been considered by Management in making judgments, estimates and assumptions used in the preparation of the Interim Financial Statements, but the inherent risks and uncertainties resulting from the pandemic may result in material changes to such judgments, estimates and assumptions in future periods as additional information becomes available.

PRODUCT TYPE INFORMATION

This MD&A includes references to sales volumes of "natural gas", "condensate and oil" and "Other NGLs" and revenues therefrom. "Natural gas" refers to conventional natural gas and shale gas combined. "Condensate and oil" refers to condensate, light and medium crude oil and tight oil combined. "Other NGLs" refers to ethane, propane and butane combined. Below is a complete breakdown of sales volumes for applicable periods by the specific product types of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil. Numbers may not add due to rounding.

	2021			2020				2019	YTD	
	Q3	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**2021**	**2020**
SALES VOLUMES - BY PRODUCT TYPE										
Shale gas (MMcf/d)	**207.1**	205.8	197.8	170.7	141.0	156.0	158.9	176.6	203.7	151.9
Conventional natural gas (MMcf/d)	**62.6**	67.3	75.3	85.6	83.0	97.2	102.6	122.4	68.3	94.2
Natural gas (MMcf/d)	**269.7**	273.1	273.1	256.3	224.0	253.2	261.5	299.0	272.0	246.1
Condensate (Bbl/d)	**29,670**	26,784	27,017	22,782	17,020	19,615	17,908	23,956	27,833	18,177
Other NGLs (Bbl/d)	**5,017**	4,938	5,170	4,987	3,952	3,817	4,539	7,064	5,041	4,102
NGLs (Bbl/d)	**34,687**	31,722	32,187	27,769	20,972	23,432	22,447	31,020	32,874	22,279
Tight oil (Bbl/d)	**475**	494	479	437	457	381	575	745	483	471
Light and medium crude oil (Bbl/d)	**2,032**	2,265	2,358	2,533	2,305	2,827	3,416	3,815	2,217	2,847
Crude oil (Bbl/d)	**2,507**	2,759	2,837	2,970	2,762	3,208	3,991	4,560	2,700	3,318
Total (Boe/d)	**82,150**	79,995	80,540	73,460	61,064	68,839	70,022	85,411	80,901	66,621

SALES VOLUMES – BY REGION BY PRODUCT TYPE										
GRANDE PRAIRIE REGION										
Shale gas (MMcf/d)	**145.8**	132.2	120.6	92.7	66.0	76.8	73.1	91.5	132.9	72.0
Conventional natural gas (MMcf/d)	**2.2**	2.1	2.0	1.6	1.3	1.5	1.5	1.9	2.1	1.4
Natural gas (MMcf/d)	**148.0**	134.3	122.6	94.3	67.3	78.3	74.6	93.4	135.0	73.4
Condensate (Bbl/d)	**26,639**	24,086	23,974	19,635	13,959	16,292	14,058	18,760	24,909	14,767
Other NGLs (Bbl/d)	**3,274**	2,874	2,984	2,429	2,060	1,680	1,680	2,376	3,045	1,807
NGLs (Bbl/d)	**29,913**	26,960	26,958	22,064	16,019	17,972	15,738	21,136	27,954	16,574
Tight oil (Bbl/d)	**–**	–	–	–	–	–	–	–	–	–
Light and medium crude oil (Bbl/d)	**9**	4	–	–	1	17	39	91	5	19
Crude oil (Bbl/d)	**9**	4	–	–	1	17	39	91	5	19
Total (Boe/d)	**54,586**	49,345	47,385	37,782	27,237	31,039	28,214	36,789	50,465	28,824

KAYBOB REGION										
Shale gas (MMcf/d)	**36.9**	39.3	42.1	41.9	40.4	44.4	48.6	48.3	39.5	44.5
Conventional natural gas (MMcf/d)	**54.4**	58.0	65.8	76.3	73.4	87.1	91.6	89.1	59.3	84.0
Natural gas (MMcf/d)	**91.3**	97.3	107.9	118.2	113.8	131.5	140.2	137.4	98.8	128.5
Condensate (Bbl/d)	**2,072**	2,319	2,611	2,631	2,577	2,954	3,385	3,899	2,332	2,971
Other NGLs (Bbl/d)	**1,415**	1,569	1,677	1,953	1,363	1,718	2,218	2,504	1,553	1,765
NGLs (Bbl/d)	**3,487**	3,888	4,288	4,584	3,940	4,672	5,603	6,403	3,885	4,736
Tight oil (Bbl/d)	**368**	354	342	299	308	203	394	541	355	302
Light and medium crude oil (Bbl/d)	**1,979**	2,224	2,321	2,480	2,257	2,762	3,343	3,331	2,173	2,785
Crude oil (Bbl/d)	**2,347**	2,578	2,663	2,779	2,565	2,965	3,737	3,872	2,528	3,087
Total (Boe/d)	**21,054**	22,688	24,938	27,056	25,477	29,561	32,700	33,167	22,879	29,232

	2021			2020				2019	YTD	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	2021	2020
CENTRAL ALBERTA & OTHER REGION										
Shale gas (MMcf/d)	24.4	34.3	35.1	36.1	34.6	34.8	37.1	36.8	31.3	35.4
Conventional natural gas (MMcf/d)	6.0	7.2	7.5	7.7	8.3	8.6	9.6	31.4	6.9	8.8
Natural gas (MMcf/d)	30.4	41.5	42.6	43.8	42.9	43.4	46.7	68.2	38.2	44.2
Condensate (Bbl/d)	959	379	433	515	484	369	465	1,298	592	439
Other NGLs (Bbl/d)	328	495	509	605	529	419	641	2,184	443	530
NGLs (Bbl/d)	1,287	874	942	1,120	1,013	788	1,106	3,482	1,035	969
Tight oil (Bbl/d)	107	140	136	138	149	178	180	203	128	169
Light and medium crude oil (Bbl/d)	44	37	37	54	47	48	33	393	39	43
Crude oil (Bbl/d)	151	177	173	192	196	226	213	596	167	212
Total (Boe/d)	6,510	7,962	8,217	8,622	8,350	8,239	9,108	15,455	7,557	8,565

	2021			2020				2019	YTD	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	2021	2020
SALES VOLUMES – KARR BY PRODUCT TYPE										
Shale gas (MMcf/d)	113.0	106.3	89.1	69.6	48.6	45.5	58.7	68.6	102.9	50.9
Conventional natural gas (MMcf/d)	1.4	1.3	1.1	0.9	0.6	0.6	0.7	0.5	1.3	0.6
Natural gas (MMcf/d)	114.4	107.6	90.2	70.5	49.2	46.1	59.4	69.1	104.2	51.5
Condensate (Bbl/d)	18,328	18,458	16,095	13,348	9,541	7,501	9,691	11,816	17,635	8,913
Other NGLs (Bbl/d)	2,477	2,281	2,108	1,817	1,503	829	1,290	1,614	2,290	1,208
NGLs (Bbl/d)	20,805	20,739	18,203	15,165	11,044	8,330	10,981	13,430	19,925	10,121
Total (Boe/d)	39,878	38,679	33,230	26,914	19,246	16,009	20,885	24,943	37,286	18,715
SALES VOLUMES – WAPITI BY PRODUCT TYPE										
Shale gas (MMcf/d)	32.7	25.9	31.5	22.8	17.4	31.3	14.5	22.9	30.0	21.1
Conventional natural gas (MMcf/d)	0.6	0.5	0.6	0.5	0.4	0.6	0.3	0.7	0.6	0.4
Natural gas (MMcf/d)	33.3	26.4	32.1	23.3	17.8	31.9	14.8	23.6	30.6	21.5
Condensate (Bbl/d)	8,310	5,629	7,884	6,286	4,414	8,786	4,364	6,865	7,276	5,849
Other NGLs (Bbl/d)	790	582	867	589	548	841	386	706	746	592
NGLs (Bbl/d)	9,100	6,211	8,751	6,875	4,962	9,627	4,750	7,571	8,022	6,441
Total (Boe/d)	14,651	10,604	14,107	10,764	7,925	14,940	7,209	11,498	13,122	10,022

The Company forecasts that fourth quarter 2021 sales volumes will average between 85,000 Boe/d and 86,500 Boe/d (55% gas and conventional natural gas combined, 39% light and medium crude oil, tight oil and condensate combined and 6% other NGLs).

The Company forecasts that 2021 annual sales volumes will average approximately 82,000 Boe/d (56% shale gas and conventional natural gas combined, 38% light and medium crude oil, tight oil and condensate combined and 6% other NGLs).

The Company forecasts that 2022 sales volumes will average between 90,000 Boe/d and 94,000 Boe/d (54% shale gas and conventional natural gas combined, 40% light and medium crude oil, tight oil and condensate combined and 6% other NGLs). First half 2022 sales volumes are expected to average between 81,000 Boe/d and 85,000 Boe/d (56% shale gas and conventional natural gas combined, 38% light and medium crude oil, tight oil and condensate combined and 6% other NGLs). Second half 2022 sales volumes are expected to average between 99,000 Boe/d and 103,000 Boe/d (53% shale gas and conventional natural gas combined, 41% light and medium crude oil, tight oil and condensate combined and 6% other NGLs).

ADVISORIES

Forward-looking Information

Certain statements in this MD&A 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:

- forecast free cash flow in 2021 and 2022;
- forecast 2021 year-end net debt to annual adjusted funds flow;
- planned capital expenditures in 2021 and 2022;
- forecast sales volumes for 2021 and 2022 and certain periods therein;
- the expectation that plateau production will be reached at Wapiti in 2023;
- the anticipated meeting by the Company of its $300 million net debt target by the end of the third quarter of 2022 and the implied net debt to adjusted funds flow ratio at the end of the third quarter of 2022;
- the Company's priorities and expectations respecting the allocation of free cash flow;
- planned abandonment and reclamation expenditures and activities in 2021 and 2022;
- preliminary anticipated capital expenditures in 2023 and the resulting expected 2023 average sales volumes and free cash flow;
- preliminary estimated drilling, completion and equipping costs;
- the payment of future dividends under the Company's monthly dividend program;
- the expectation that all holders will exercise their right to convert their Convertible Debentures into Common Shares prior to the redemption date;
- planned exploration, development and production activities, including the expected timing of drilling, completing and bringing new wells on production;
- the expectation that the Company will be able to fund budgeted capital expenditures in 2021 and 2022 with cash from operating activities;
- the anticipation that legal proceedings will not have a material impact on Paramount's financial position; and
- the potential impacts of the COVID-19 pandemic.

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 commodity prices and the potential impact of the COVID-19 pandemic thereon;
- the likely impact of the COVID-19 pandemic on operations;
- the ability to realize expected cost savings;
- 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 performance of wells and facilities;
- 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 and the capacity and reliability of facilities;

- the ability of Paramount to market its production 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, product yields and resource recoveries) and operational improvements, efficiencies and results consistent with expectations;
- the timely receipt of required governmental and regulatory approvals;
- the receipt of benefits under government programs;
- the application of regulatory requirements respecting abandonment and reclamation;
- the merits of outstanding and pending legal proceedings;
- anticipated timelines and budgets being met in respect of drilling programs and other operations (including well completions and tie-ins, the construction, commissioning and start-up of new and expanded facilities, including third-party facilities and facility turnarounds and maintenance); and
- in the case of the expectation that all holders will exercise their right to convert their Convertible Debentures into Common Shares prior to the redemption date, the assumption that the trading price of the Common Shares will continue to remain substantially above the conversion price of the Convertible Debentures.

Although Paramount believes that the expectations reflected in such forward-looking information are reasonable based on the information available at the time of this MD&A, 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:

- those risks set out in this MD&A under "Risk Factors";
- fluctuations in commodity prices, including in relation to the impact of the COVID-19 pandemic;
- the potential for changes to preliminary anticipated 2023 capital expenditures prior to finalization and changes to the resulting expected 2023 average sales volumes and free cash flow;
- changes in capital spending plans and planned exploration and development activities;
- changes in foreign currency exchange rates and interest rates;
- the uncertainty of estimates and projections relating to future revenue, free cash flow, production, reserves additions, product 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 sales volumes, 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 operating activities 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 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.

There are risks that may result in the Company changing, suspending or discontinuing its monthly dividend program, including changes to free cash flow, operating results, capital requirements, financial position, market conditions or corporate strategy and the need to comply with requirements under debt agreements and applicable laws respecting the declaration and payment of dividends. There are no assurances as to the continuing declaration and payment of future dividends under the Company's monthly dividend program or the amount or timing of any such dividends.

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, 2020, 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.

Certain forward-looking information in this MD&A, including forecast free cash flow in 2021, 2022 and future periods and forecast 2021 and 2022 net debt to annual adjusted funds flow ratios, may also constitute a "financial outlook" within the meaning of applicable securities laws. A financial outlook involves statements about Paramount's prospective financial performance or position and is based on and subject to the assumptions and risk factors described above in respect of forward-looking information generally as well as any other specific assumptions and risk factors in relation to such financial outlook noted in this MD&A. Such assumptions are based on management's assessment of the relevant information currently available and any financial outlook included in this MD&A is provided for the purpose of helping readers understand Paramount's current expectations and plans for the future. Readers are cautioned that reliance on any financial outlook may not be appropriate for other purposes or in other circumstances and that the risk factors described above or other factors may cause actual results to differ materially from any financial outlook.

Non-GAAP Financial Measures

In this document, "adjusted funds flow", "free cash flow", "netback", "net debt", "adjusted working capital" "net debt to adjusted funds flow" and "total capital expenditures", collectively the "Non-GAAP Financial Measures", are used and do not have any standardized meanings as prescribed by IFRS.

"Adjusted funds flow" refers to cash from (used in) operating activities before net changes in non-cash working capital, geological and geophysical expenses, asset retirement obligation settlements, closure costs, provisions and other, dispute settlements 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 obligation 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 managing its asset retirement obligations and, as a result, amounts incurred may vary significantly 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 from operating activities as determined in accordance with IFRS. Refer to the Consolidated Results section of this MD&A for the calculation thereof.

"Free cash flow" refers to adjusted funds flow less total capital expenditures and asset retirement obligation settlements. Free cash flow is used by Management and investors to assess the amount of internally generated cash available to repay debt, reinvest in the business or return to shareholders.

The following is the reconciliation of free cash flow from the nearest GAAP measure for the three months ended September 30, 2021 and June 30, 2021:

Three months ended ($ millions)	September 30, 2021	June 30, 2021
Cash from operating activities	**97.0**	**112.1**
Change in non-cash working capital	42.9	(47.6)
Geological and geophysical expenses	1.6	1.8
Asset retirement obligations settled	6.9	3.2
Closure costs	–	–
Provisions and other	–	16.5
Transaction and reorganization costs	–	–
Adjusted funds flow	**148.4**	**86.0**
Total capital expenditures	(68.9)	(83.5)
Asset retirement obligation settlements	(6.9)	(3.2)
Free cash flow	**72.6**	**(0.7)**

"Netback" equals petroleum and natural gas sales less royalties, operating expense 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".

"Net debt to adjusted funds flow" is a ratio calculated as the period end net debt divided by adjusted funds flow for the trailing four quarters. The ratio of net debt to adjusted funds flow is commonly used by management and investors to assess the Company's overall debt position.

"Total capital expenditures" refers to the Company's property, plant and equipment and exploration expenditures. Refer to the Total Capital Expenditures section of this MD&A for the calculation thereof.

The Non-GAAP Financial 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 Financial Measures are unlikely to be comparable to similar measures presented by other issuers.

Oil and Gas Measures and Definitions

Abbreviations

Liquids	
Bbl	Barrels
Bbl/d	Barrels per day
NGLs	Natural gas liquids
Condensate	Pentane and heavier hydrocarbons
WTI	West Texas Intermediate

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

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

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, 2021, the value ratio between crude oil and natural gas was approximately 26:1. 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, 2021

INTERIM CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)
($ thousands)

As at	Note	September 30 2021	December 31 2020
ASSETS			
Current assets			
Cash and cash equivalents	15	1,414	4,590
Accounts receivable		142,478	99,986
Risk management – current	12	467	408
Prepaid expenses and other		13,764	9,931
		158,123	114,915
Lease receivable	7	985	2,758
Dissent payment entitlement	4	–	89,250
Investments in securities	5	302,924	59,529
Risk management – long-term	12	418	–
Exploration and evaluation	2	544,638	612,129
Property, plant and equipment, net	3	2,283,889	1,959,603
Deferred income tax	11	591,874	658,811
		3,882,851	3,496,995
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities		209,675	152,756
Risk management – current	12	89,657	32,281
Asset retirement obligations and other – current	7	30,769	32,229
		330,101	217,266
Long-term debt	6	522,397	813,491
Risk management – long-term	12	6,411	19,441
Asset retirement obligations and other – long-term	7	612,879	409,016
		1,471,788	1,459,214
Commitments and contingencies	16		
Shareholders' equity			
Share capital	8	2,208,718	2,207,408
Accumulated deficit		(97,778)	(235,061)
Equity component of convertible debentures	6	1,673	–
Reserves	9	298,450	65,434
		2,411,063	2,037,781
		3,882,851	3,496,995

See the accompanying notes to these Interim Condensed Consolidated Financial Statements

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)

($ thousands, except as noted)

	Note	Three months ended September 30 2021	Three months ended September 30 2020	Nine months ended September 30 2021	Nine months ended September 30 2020
Petroleum and natural gas sales		369,137	138,756	948,704	424,019
Royalties		(30,923)	(4,326)	(74,491)	(19,608)
Revenue	13	338,214	134,430	874,213	404,411
Gain (loss) on financial commodity contracts	12	(47,010)	(2,084)	(203,905)	32,994
		291,204	132,346	670,308	437,405
Expenses					
Operating expense		83,313	62,361	249,383	217,302
Transportation and NGLs processing		30,279	27,817	88,426	76,728
General and administrative		10,367	7,759	29,691	23,745
Share-based compensation	10	3,017	5,605	11,111	6,176
Depletion, depreciation and impairment (reversal)	3	(209,794)	28,960	32,753	259,875
Exploration and evaluation	2	6,695	1,708	29,711	25,154
(Gain) loss on sale of oil and gas assets	3	(32,296)	7,962	(72,104)	8,742
Interest and financing		8,691	17,121	38,042	35,869
Accretion of asset retirement obligations	7	10,573	11,002	32,140	32,144
Reorganization costs		–	–	–	3,048
Settlement of dissent payment entitlement	4	–	–	22,595	–
Foreign exchange		(1,243)	351	(145)	31
		(90,398)	170,646	461,603	688,814
Other income (loss)	14	190	(3,520)	(23,770)	(8,122)
Income (loss) before tax		381,792	(41,820)	184,935	(259,531)
Income tax expense (recovery)					
Deferred	11	89,132	(18,481)	49,030	74,614
		89,132	(18,481)	49,030	74,614
Net income (loss)		292,660	(23,339)	135,905	(334,145)
Other comprehensive income (loss), net of tax	9				
Items that will be reclassified to net income (loss)					
Change in fair value of cash flow hedges, net of tax		617	(436)	6,396	(21,843)
Reclassification to net income (loss), net of tax		1,483	1,807	4,493	3,873
Items that will not be reclassified to net income (loss)					
Change in fair value of securities, net of tax		66,241	(1,327)	218,824	(33,682)
Comprehensive income (loss)		361,001	(23,295)	365,618	(385,797)
Net income (loss) per common share ($/share)	8				
Basic		2.20	(0.17)	1.02	(2.50)
Diluted		2.06	(0.17)	0.97	(2.50)

See the accompanying notes to these Interim Condensed Consolidated Financial Statements

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

($ thousands)

	Note	Three months ended September 30 2021	Three months ended September 30 2020	Nine months ended September 30 2021	Nine months ended September 30 2020
Operating activities					
Net income (loss)		292,660	(23,339)	135,905	(334,145)
Add (deduct):					
Items not involving cash	15	(145,879)	51,133	160,280	402,180
Asset retirement obligations settled	7	(6,879)	(732)	(18,381)	(34,947)
Change in non-cash working capital		(42,890)	(15,626)	12,590	(5,356)
Cash from operating activities		97,012	11,436	290,394	27,732
Financing activities					
Net draw (repayment) of revolving long-term debt	6	(86,984)	37,119	(326,554)	159,752
Lease liabilities – principal repayments	7	(1,952)	(1,897)	(5,737)	(5,671)
Convertible debentures issued, net of issue costs		–	–	34,919	–
Dividends		(8,088)	–	(8,088)	–
Common Shares issued, net of issue costs		621	–	5,113	15
Common Shares repurchased under NCIB	8	(2,703)	–	(2,703)	–
Common Shares purchased under restricted share unit plan	10	–	–	(10,691)	–
Cash from (used in) financing activities		(99,106)	35,222	(313,741)	154,096
Investing activities					
Property, plant and equipment and exploration		(68,891)	(50,512)	(211,697)	(155,763)
Proceeds of disposition		86,518	389	165,737	(1,743)
Investments		–	(60)	(1,012)	(997)
Proceeds from dissent payment entitlement, net		–	–	66,782	–
Change in non-cash working capital		(16,329)	3,160	174	(27,817)
Cash from (used in) investing activities		1,298	(47,023)	19,984	(186,320)
Net decrease		(796)	(365)	(3,363)	(4,492)
Foreign exchange on cash and cash equivalents		233	(190)	187	(470)
Cash and cash equivalents, beginning of period		1,977	1,609	4,590	6,016
Cash and cash equivalents, end of period		1,414	1,054	1,414	1,054
Supplemental cash flow information	15				

See the accompanying notes to these Interim Condensed Consolidated Financial Statements

INTERIM CONDENSED CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(Unaudited)

($ thousands, except as noted)

Nine months ended September 30	Note	2021		2020	
		Shares (000's)		*Shares (000's)*	
Share capital					
Balance, beginning of period		***132,284***	**2,207,408**	*133,337*	2,207,485
Issued		***742***	**6,557**	*1*	19
Common Shares repurchased and cancelled under NCIB	8	***(198)***	**(2,703)**	–	–
Change in Common Shares for restricted share unit plan	10	***379***	**(2,544)**	*446*	89
Balance, end of period	8	***133,207***	**2,208,718**	*133,784*	2,207,593
Accumulated deficit					
Balance, beginning of period			**(235,061)**		(128,487)
Net income (loss)			**135,905**		(334,145)
Dividends			**(8,088)**		–
Recognition of deferred income tax asset	11		**9,466**		–
Reclassification of accumulated losses on securities			**–**		(83,881)
Balance, end of period			**(97,778)**		(546,513)
Equity component of convertible debentures	6				
Balance, beginning of period			**–**		–
Issued			**1,673**		–
Balance, end of period			**1,673**		–
Reserves	9				
Balance, beginning of period			**65,434**		4,182
Other comprehensive income (loss)			**229,713**		(51,652)
Contributed surplus			**3,303**		7,949
Reclassification of accumulated losses on securities			**–**		83,881
Balance, end of period			**298,450**		(44,360)
Total shareholders' equity			**2,411,063**		1,705,440

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 reserves and resources. The Company also pursues longer-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 Inc. 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. Intercompany balances and transactions have been eliminated.

These unaudited Interim Condensed Consolidated Financial Statements, as at and for the three and nine months ended September 30, 2021 (the "Interim Financial Statements"), were authorized for issuance by the Audit Committee of Paramount's Board of Directors on November 3, 2021.

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, 2020 (the "Annual Financial Statements"). Certain comparative figures have been reclassified to conform to the current years' presentation.

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 have been condensed or omitted. These Interim Financial Statements should be read in conjunction with the Annual Financial Statements.

Adoption of Accounting Standards

Financial Instruments

Effective January 1, 2021, the Company adopted the phase two amendments to IFRS 9 – *Financial Instruments,* IAS 39 – *Financial Instruments: Recognition and Measurement*, IFRS 7 – *Financial Instruments: Disclosures,* IFRS 4 – *Insurance Contracts and* IFRS 16 – *Leases*. These amendments provide guidance in applying IFRS when there are changes to contractual cash flows or hedging relationships arising from the replacement of an interest rate benchmark with an alternative benchmark rate pursuant to the Interbank Offered Rate ("IBOR") reform. There has been no impact on the recognized assets, liabilities or comprehensive income (loss) of the Company resulting from the adoption of these amendments. The Company's floating-to-fixed interest rate swaps, which are described in Note 12, may be impacted by these amendments in the future as hedge accounting is applied to these instruments and hedging relationships may be impacted by the IBOR reform.

Significant Accounting Estimates, Assumptions & Judgments

The timely preparation of financial statements requires Management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosures regarding contingent assets and liabilities. Estimates and assumptions are regularly evaluated and are based on Management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Changes in judgments, estimates and assumptions based on new information could result in a material change to the carrying amount of assets or liabilities and have a material impact on assets, liabilities, revenues and expenses recognized in future periods.

The course of the COVID-19 pandemic and its impacts remain highly uncertain. The impacts of the pandemic on Paramount's future operations and financial performance are unknown and are dependent on a number of unpredictable factors outside of the knowledge and control of Management, including: (i) the duration and severity of the pandemic; (ii) the impact of the pandemic on economic growth, inflation, supply chains, commodity prices and financial and capital markets; and (iii) governmental responses and restrictions. These uncertainties may continue to persist beyond the point where the outbreak of the COVID-19 virus has subsided. The potential impacts of the COVID-19 pandemic have been considered by Management in making judgments, estimates and assumptions used in the preparation of these Interim Financial Statements, but the inherent risks and uncertainties resulting from the pandemic may result in material changes to such judgments, estimates and assumptions in future financial periods as additional information becomes available.

2. Exploration and Evaluation

	Nine months ended September 30, 2021	Twelve months ended December 31, 2020
Balance, beginning of period	**612,129**	650,414
Additions	**7,641**	3,294
Change in asset retirement obligations	**1,047**	(724)
Transfers to property, plant and equipment	**(12,745)**	(8,735)
Expired lease costs	**(24,541)**	(25,585)
Dispositions (see Note 3)	**(38,893)**	(6,535)
Balance, end of period	**544,638**	612,129

Exploration and Evaluation Expense

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Geological and geophysical	**1,594**	1,708	**5,170**	6,233
Expired lease costs	**5,101**	–	**24,541**	18,921
	6,695	1,708	**29,711**	25,154

At September 30, 2021, the Company assessed its exploration and evaluation assets for indicators of potential impairment or impairment reversal and none were identified.

3. Property, Plant and Equipment

Nine months ended September 30, 2021	Petroleum and natural gas assets	Drilling rigs	Right-of-use assets	Other	Total
Cost					
Balance, beginning of period	4,125,044	162,476	15,459	48,053	**4,351,032**
Additions	206,104	3,706	902	1,928	**212,640**
Transfers from exploration and evaluation	12,745	–	–	–	**12,745**
Dispositions	(183,763)	–	(277)	–	**(184,040)**
Change in asset retirement obligations	92,112	–	–	–	**92,112**
Cost, end of period	4,252,242	166,182	16,084	49,981	**4,484,489**
Accumulated depletion, depreciation and net impairment					
Balance, beginning of period	(2,245,733)	(99,902)	(8,670)	(37,124)	**(2,391,429)**
Depletion and depreciation	(211,010)	(7,138)	(2,513)	(2,704)	**(223,365)**
Impairment reversal	296,630	–	–	–	**296,630**
Dispositions	117,353	–	211	–	**117,564**
Accumulated depletion and depreciation, end of period	(2,042,760)	(107,040)	(10,972)	(39,828)	**(2,200,600)**
Net book value, December 31, 2020	1,879,311	62,574	6,789	10,929	**1,959,603**
Net book value, September 30, 2021	2,209,482	59,142	5,112	10,153	**2,283,889**

In the third quarter of 2021, Paramount closed the sale of its non-operated Birch assets in northeast British Columbia (the "Birch Property"), which were included in the Northern cash generating unit ("CGU"), for proceeds of approximately $85 million (the "Birch Disposition"). The Birch Property was reclassified as held for sale as at June 30, 2021. As the consideration received on the Birch Disposition exceeded the carrying value of the asset, which had previously been reduced by impairment charges, a reversal of previously recorded impairment charges of $14.1 million was recorded for the three months ended June 30, 2021. This reversal represented the amount required to increase the carrying value of the Birch Property to the amount that would have been determined, net of depletion and amortization, had no impairment charges been recognized in prior periods. A gain of $36 million was recognized on the Birch Disposition for the three months ended September 30, 2021.

In the first quarter of 2021, the Company sold certain properties in the Kaybob and Central Alberta CGUs for proceeds of approximately $79 million. A gain of $39 million was recognized on these sales.

Depletion, Depreciation and Impairment (Reversal)

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Depletion and depreciation	**74,963**	54,579	**220,040**	189,055
Change in asset retirement obligations	**(2,191)**	(25,619)	**109,343**	(120,976)
Impairment of petroleum and natural gas assets / (reversal)	**(282,566)**	–	**(296,630)**	191,796
	(209,794)	28,960	**32,753**	259,875

For the nine months ended September 30, 2021, the Company recorded a charge of $109.3 million (nine months ended September 30, 2020 a recovery of $121.0 million) to earnings mainly 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 property, plant and equipment. The changes mainly resulted from a revision in the credit-adjusted risk-free rate used to discount these obligations and also included a recovery for the nine months ended September 30, 2021 of $3.4 million (twelve months ended December 31, 2020 - $4.4 million) in respect of funding under the Alberta Site Rehabilitation Program (refer to Note 7).

At September 30, 2021, the Company recorded an aggregate of $282.6 million in reversals of previously recorded impairment charges to petroleum and natural gas assets, comprised of $270.3 million related to the Kaybob CGU and $12.3 million related to the Northern CGU. The impairment reversals resulted from an increase in the estimated recoverable amount of such CGUs compared to the prior impairment assessment performed at December 31, 2020.

The $282.6 million in aggregate impairment reversals represent the amount to bring the carrying values of the Kaybob and Northern CGUs to the amounts, net of depletion and amortization, had no impairment charges been recognized in prior periods. The increase in the estimated recoverable amount of these CGUs was mainly due to higher and sustained forecasted condensate, crude oil and natural gas prices and the increase in the Company's market capitalization since the prior impairment assessment performed at December 31, 2020.

The recoverable amount of the Kaybob and Northern CGUs as at September 30, 2021 was estimated on a fair value less costs of disposal basis, using a discounted cash flow method (level 3 fair value hierarchy estimate). Cash flows were projected over the expected remaining productive life of the proved plus probable reserves assigned to the Kaybob and Northern CGUs, at discount rates of 11.0 percent and 13.0 percent, respectively. The net cash flows from the proved plus probable reserves estimated by Paramount's independent qualified reserves evaluator as at December 31, 2020 were mechanically updated by Management to October 1, 2021, including to reflect commodity price estimates at October 1, 2021. The reserves evaluation process is inherently subjective and involves considerable estimation uncertainty.

The following table sets out the forecast benchmark commodity prices and exchange rates used to determine estimated recoverable amounts at October 1, 2021[(1)]:

(Average for the period)	(Oct-Dec) 2021	2022	2023	2024	2025	2026-2033	Thereafter
Natural Gas [(2)]							
AECO ($/MMBtu)	4.57	3.83	3.26	2.99	3.05	3.12 – 3.72	+2%/yr
Henry Hub (US$/MMBtu)	5.40	4.25	3.44	3.17	3.24	3.30 – 3.95	+2%/yr
Crude Oil and Condensate [(2)]							
Edmonton Condensate ($/Bbl)	94.79	88.36	83.33	80.56	82.16	83.81 – 100.16	+2%/yr
WTI (US$/Bbl)	75.17	71.00	67.77	65.57	66.88	68.22 – 81.52	+2%/yr
Foreign Exchange							
$US / 1 $CDN	0.795	0.798	0.80	0.80	0.80	0.80	0.80

(1) Average of forecasts published by: (i) McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. at October 1, 2021 and (ii) Sproule Associates Ltd. at September 30, 2021.
(2) Forecast benchmark prices are adjusted for quality differentials, heat content, distance to market and other factors in determining estimated recoverable amounts.

At December 31, 2020, the Company recorded aggregate impairment reversals of $333.7 million from previously recorded impairment charges to petroleum and natural gas assets in the Kaybob, Northern and Central Alberta CGUs, comprised of $287.7 million, $30.6 million and $15.4 million, respectively. The impairment reversals resulted from an increase in the estimated recoverable amount of such CGUs compared to the prior impairment assessment performed at March 31, 2020. The increase in the estimated recoverable amount of these CGUs was mainly attributable to lower operating and capital costs than previously forecasted and changes in the development plan.

At March 31, 2020, the Company recorded impairments of $188.3 million and $3.5 million related to petroleum and natural gas assets in the Kaybob and Northern CGUs, respectively. The impairments were recorded because the carrying value of the CGUs exceeded their estimated recoverable amounts, which were estimated based on expected net cash flows from the production of proved plus probable reserves ascribed to each CGU. The impairments resulted from decreases in estimated future net revenues, mainly due to lower forecasted oil and natural gas prices.

For additional information on impairments and impairment reversals in 2020, refer to Note 5 of the Annual Financial Statements.

4. Dissent Payment Entitlement

As at	September 30, 2021	December 31, 2020
Dissent Payment Entitlement	–	89,250

Paramount held 85 million common shares of Strath Resources Ltd. ("Strath") prior to its amalgamation with Cona Resources Ltd. in August 2020 to form Strathcona Resources Ltd. ("Strathcona"). Paramount objected to the amalgamation and exercised its right of dissent under section 191 of the *Business Corporations Act* (Alberta) with respect to its Strath shares. As a result, the Company was entitled to be paid in cash the fair value of its Strath shares, determined as of the close of business on July 24, 2020 (the "Dissent Payment Entitlement").

In the second quarter of 2021, Paramount received $67 million cash in settlement of the dissent proceedings and for the sale of its remaining securities in Strathcona. A loss of $22.6 million was recognized on the settlement.

5. Investments in Securities

As at	September 30, 2021	December 31, 2020
Level one fair value hierarchy securities ("Level One Securities")	231,001	48,425
Level three fair value hierarchy securities ("Level Three Securities")	71,923	11,104
	302,924	59,529

Paramount holds investments in a number of publicly-traded and private corporations as part of its portfolio of investments. Investments that are categorized as Level One Securities are carried at their period-end trading prices. Estimates of fair values for investments that are categorized as Level Three 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 including financial and operating results of the entities. Fair value estimates of Level Three 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.

For the three and nine months ended September 30, 2021, the Company recorded $74.7 million and $242.4 million, respectively, to other comprehensive income ("OCI") as a result of changes in the fair value estimates of investments in securities.

Changes in the fair value of investments in securities are as follows:

	Nine months ended September 30, 2021	Twelve months ended December 31, 2020
Investments in securities, beginning of period	59,529	156,889
Changes in fair value of Level One Securities – recorded in OCI	181,576	(50,632)
Changes in fair value of Level Three Securities – recorded in OCI	60,822	32,547
Transfer to Dissent Payment Entitlement – see Note 4	–	(89,250)
Derecognition of Strathcona warrants – see Note 4	(127)	–
Changes in fair value of Strathcona warrants – recorded in earnings	112	(1,692)
Additions	1,012	11,667
Investments in securities, end of period	302,924	59,529

6. Long-Term Debt

As at	September 30, 2021	December 31, 2020
Paramount Facility (1)	489,168	813,491
Convertible Debentures	33,229	–
Long-term debt	522,397	813,491

(1) Paramount Facility presented net of $3.4 million in unamortized transaction costs (December 31, 2020 - $2.2 million).

Paramount Facility

In June 2021, the Company renewed its financial covenant-based senior secured revolving bank credit facility (the "Paramount Facility").

The Paramount Facility currently has a credit limit of $900 million, which can be increased to $1.0 billion at Paramount's request pursuant to an accordion feature in the facility, subject to incremental lender commitments. The maturity date of the facility is June 2, 2024. The Paramount Facility is secured by a charge over substantially all of the assets of the Company and its subsidiaries.

Borrowings under the Paramount Facility bear interest at the prime lending rate, US base rate, CDOR, or LIBOR, as selected by the Company, plus an applicable margin which varies based on the Company's Senior Secured Debt to Consolidated EBITDA ratio.

Paramount is subject to the following two financial covenants under the Paramount Facility which are tested at the end of each fiscal quarter and calculated on a trailing twelve-month basis:

- Senior Secured Debt to Consolidated EBITDA to be 3.50 to 1.00 or less; and
- Consolidated EBITDA to Consolidated Interest Expense to be 2.50 to 1.00 or greater.

Senior Secured Debt currently consists of amounts drawn on the Paramount Facility.

Consolidated EBITDA is adjusted for material acquisitions and dispositions and is generally calculated as net income before Consolidated Interest Expense, taxes, depletion, depreciation, amortization, impairment and exploration and evaluation expense and is also adjusted to exclude non-recurring items and other non-cash items including gains or losses on dispositions of oil and gas assets, unrealized mark-to-market amounts on derivatives, unrealized foreign exchange gains and losses, share-based compensation expense and accretion.

Consolidated Interest Expense is reduced by customary adjustments including interest income.

Paramount was in compliance with the financial covenants under the Paramount Facility at September 30, 2021.

The Company had undrawn letters of credit outstanding under the Paramount Facility totaling $2.3 million at September 30, 2021 that reduce the amount available to be drawn on the facility.

Unsecured Letter of Credit Facility

The Company has a $70 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 ("PSG") from Export Development Canada. In May 2021, the PSG was extended to June 30, 2022.

At September 30, 2021, $42.6 million in undrawn letters of credit were outstanding under the LC Facility (December 31, 2020 – $40.7 million).

Convertible Debentures

Nine months ended September 30, 2021	Liability Component [(1)]	Equity Component
Balance, beginning of period	–	–
Issued, net of issue costs	32,746	2,176
Deferred taxes	–	(503)
Accretion	483	–
Balance, end of period	**33,229**	**1,673**

(1) For the nine months ended September 30, 2021, $1.8 million in interest payments were made on the Convertible Debentures.

In January 2021, the Company completed a private placement of $35.0 million of senior unsecured convertible debentures (the "Convertible Debentures"). An entity controlled by Paramount's President and Chief Executive Officer and Chairman purchased $25.0 million of the Convertible Debentures. The Convertible Debentures mature on January 31, 2024 (the "Maturity Date"), bear interest at 7.50 percent per annum payable monthly in arrears and are convertible by the holder into Common Shares at any time prior to the Maturity Date. At September 30, 2021, the conversion price of the debentures was $6.69 per Common Share if converted prior to January 31, 2022, $7.30 per Common Share if converted on or after January 31, 2022 and prior to January 31, 2023 and $7.91 per Common Share if converted on or after January 31, 2023. These prices are subject to customary anti-dilution adjustments.

The Convertible Debentures are redeemable by Paramount, in whole or in part, at any time prior to the Maturity Date, at a redemption price (expressed as percentages of principal amount) equal to 107.50 percent prior to January 31, 2022, 103.75 percent on or after January 31, 2022 and prior to January 31, 2023 and 101.875 percent on or after January 31, 2023.

The Convertible Debentures are treated as a compound financial instrument that contain a liability and an equity component and were initially recognized at fair value, net of issue costs of $0.1 million. The fair value of the liability component was initially recognized at the date of issuance using the effective interest method, discounted using the estimated interest rate of a debt instrument having similar terms but without a conversion feature. The fair value of the conversion feature was determined at the date of issuance as the difference between the principal amount and the fair value of the liability component at the date of issue, which has been classified within shareholders' equity.

The liability component of the Convertible Debentures is carried at amortized cost and is accreted over the term of the Convertible Debentures to the principal amount using the effective interest method. This accretion, along with interest on the Convertible Debentures, is recorded as interest and financing expense. The equity component is not remeasured subsequent to initial recognition. The equity component and the accreted liability component will be reclassified to share capital should the Convertible Debentures be converted into Common Shares.

As at September 30, 2021, there were $35.0 million aggregate principal amount of Convertible Debentures outstanding.

7. Asset Retirement Obligations and Other

As at September 30, 2021	Current	Long-term	Total
Asset retirement obligations	20,200	608,375	628,575
Lease liabilities	10,569	4,504	15,073
Asset retirement obligations and other	**30,769**	**612,879**	**643,648**

As at December 31, 2020	Current	Long-term	Total
Asset retirement obligations	22,250	397,276	419,526
Lease liabilities	9,979	11,740	21,719
Asset retirement obligations and other	**32,229**	**409,016**	**441,245**

Asset Retirement Obligations

	Nine months ended September 30, 2021	Twelve months ended December 31, 2020
Asset retirement obligations, beginning of period	419,526	569,897
Additions	774	507
Change in estimates	(1,300)	(7,605)
Change in discount rate	206,410	(145,178)
Obligations settled – cash	(18,381)	(34,994)
Obligations settled – funding under the Alberta site rehabilitation program	(3,383)	(4,423)
Dispositions	(7,211)	(2,036)
Accretion expense	32,140	43,358
Asset retirement obligations, end of period	628,575	419,526

As at September 30, 2021, estimated undiscounted, uninflated asset retirement obligations were $1,287.2 million (December 31, 2020 – $1,351.7 million). Asset retirement obligations have been determined using a credit-adjusted risk-free discount rate of 7.0 percent (December 31, 2020 – 11.0 percent) and an inflation rate of 2.0 percent (December 31, 2020 – 2.0 percent).

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. For the nine months ended September 30, 2021, total cash payments made in respect of these lease liabilities, net of sublease arrangements, were $6.3 million (September 30, 2020 – $6.5 million), of which $0.6 million (September 30, 2020 – $0.8 million) was recognized as interest and financing expense.

For the nine months ended September 30, 2021, expenses related to arrangements containing variable operating costs, short-term and low value leases which have not been included in the lease liability were approximately $1.9 million (September 30, 2020 – $2.6 million).

As at September 30, 2021, $3.4 million (December 31, 2020 – $5.1 million) was due to the Company in respect of sublease arrangements for Paramount's office space, of which $2.4 million (December 31, 2020 – $2.3 million) was classified as current and $1.0 million (December 31, 2020 – $2.8 million) was classified as non-current. For the nine months ended September 30, 2021, $1.9 million (September 30, 2020 – $1.9 million) was received in respect of office sublease arrangements, of which $0.2 million (September 30, 2020 – $0.3 million) was recognized as interest revenue.

8. Share Capital

As at September 30, 2021, 133,206,722 (December 31, 2020 – 132,284,323) class A common shares of the Company ("Common Shares") were outstanding, net of 1,536,075 (December 31, 2020 – 1,914,394) Common Shares held in trust under the restricted share unit plan.

In June 2021, Paramount announced the implementation of a regular monthly dividend with respect to its Common Shares. Dividends declared for the nine months ended September 30, 2021 were $0.06 per share.

In June 2021, Paramount implemented a normal course issuer bid program (the "NCIB") under which the Company may purchase up to 7,308,743 Common Shares for cancellation. The NCIB will terminate on the earlier of June 29, 2022 and the date on which the maximum number of Common Shares that can be acquired pursuant to the NCIB are purchased. Purchases of Common Shares under the NCIB will be effected through the facilities of the TSX or alternative Canadian trading systems at the market price at the time of purchase. The Company has repurchased and cancelled 197,500 Common Shares at a total cost of $2.7 million under the NCIB to September 30, 2021.

Weighted Average Common Shares

Three months ended September 30	2021		2020	
	Wtd. Avg. Shares (000's)	Net income	*Wtd. Avg. Shares (000's)*	Net loss
Net income (loss) – basic	*132,818*	292,660	*133,784*	(23,339)
Dilutive effect of Convertible Debentures	*5,208*	645	–	–
Dilutive effect of Paramount Options	*4,653*	–	–	–
Net income (loss) – diluted	*142,679*	293,305	*133,784*	(23,339)

Nine months ended September 30	2021		2020	
	Wtd. Avg. Shares (000's)	Net income	*Wtd. Avg. Shares (000's)*	Net loss
Net income (loss) – basic	*132,977*	135,905	*133,615*	(334,145)
Dilutive effect of Convertible Debentures	*4,598*	1,749	–	–
Dilutive effect of Paramount Options	*3,939*	–	–	–
Net income (loss) – diluted	*141,514*	137,654	*133,615*	(334,145)

Outstanding stock options and Convertible Debentures 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. For the three and nine months ended September 30, 2021, 1.2 million and 2.5 million options to acquire Common Shares ("Paramount Options") were anti-dilutive, respectively (three and nine months ended September 30, 2020 - 6.7 million Paramount Options were anti-dilutive).

9. Reserves

Nine months ended September 30, 2021	Unrealized gains (losses) on cash flow hedges	Unrealized gains (losses) on securities	Contributed surplus	Total reserves
Balance, beginning of period	(22,011)	(79,638)	167,083	65,434
Other comprehensive income, before tax	14,187	242,398	–	256,585
Deferred tax	(3,298)	(23,574)	–	(26,872)
Share-based compensation	–	–	4,747	4,747
Paramount Options exercised	–	–	(1,444)	(1,444)
Balance, end of period	**(11,122)**	**139,186**	**170,386**	**298,450**

10. Share-Based Compensation

Paramount Options

	Nine months ended September 30, 2021		Twelve months ended December 31, 2020	
	Number	Weighted average exercise price ($/share)	*Number*	Weighted average exercise price ($/share)
Balance, beginning of period	*9,681,395*	6.91	*12,311,462*	12.16
Granted	*3,135,000*	16.19	*3,111,500*	3.82
Exercised [(1)]	*(741,580)*	6.90	*(2,000)*	7.28
Cancelled or forfeited	*(187,533)*	7.37	*(4,366,829)*	17.97
Expired	*(41,800)*	15.97	*(1,372,738)*	11.82
Balance, end of period	*11,845,482*	9.33	*9,681,395*	6.91
Options exercisable, end of period	*1,657,491*	10.90	*2,416,871*	9.74

(1) For Paramount Options exercised during the nine months ended September 30, 2021, the weighted average market price of Common Shares on the dates exercised was $11.68 per share (twelve months ended December 31, 2020 – $7.77 per share).

The grant date fair value of Paramount Options and related weighted average inputs, estimated using the Black-Scholes-Merton model, are as follows:

	Options awarded in 2021
Weighted average exercise price ($ / share)	16.19
Volatility (%)	44
Expected life of share options (years)	4.3
Pre-vest annual forfeiture rate (%)	12.8
Risk-free interest rate (%)	0.8
Expected dividend yield (%)	1.5
Weighted average fair value of awards ($ / option)	5.16

The expected life of Paramount Options is based on historical exercise patterns. Volatility is generally estimated based on the historical volatility of the trading price of Common Shares over the most recent period that is commensurate with the expected term of the option and is normalized for significant transactions and other factors.

Restricted Share Unit Plan – Shares Held in Trust

	Nine months ended September 30, 2021		Twelve months ended December 31, 2020	
	Shares (000's)		*Shares (000's)*	
Balance, beginning of period	*1,915*	1,484	*860*	1,388
Shares purchased	*1,088*	10,691	*1,600*	4,081
Change in vested and unvested shares	*(1,467)*	(8,147)	*(545)*	(3,985)
Balance, end of period	*1,536*	4,028	*1,915*	1,484

11. Income Tax

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

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Income (loss) before tax	381,792	(41,820)	184,935	(259,531)
Effective Canadian statutory income tax rate	23.1%	25.1%	23.1%	25.1%
Expected income tax expense (recovery)	88,194	(10,497)	42,720	(65,142)
Effect on income taxes of:				
Change in statutory and other rates	687	(874)	1,872	7,839
Loss on dissent payment entitlement	–	–	2,610	–
Change in unrecognized deferred income tax asset	278	(7,770)	(267)	126,482
Share-based compensation	539	1,378	1,097	1,996
(Gain) loss on sale of oil and gas assets	(113)	–	(113)	411
Flow-through share renunciations	–	–	–	3,617
Non-deductible items and other	(453)	(718)	1,111	(589)
Income tax expense (recovery)	89,132	(18,481)	49,030	74,614

During the nine months ended September 30, 2021 the Company recognized $82.0 million of deductible temporary differences for which no deferred income tax asset had been previously recorded as a result of taxable temporary differences arising in the period in respect of investments in securities. The deferred income tax asset was increased by $9.5 million, the tax effected amount of such temporary differences, and the accumulated deficit was reduced by a corresponding amount as the previously unrecognized temporary differences relate to disposed or derecognized investments in securities.

12. Financial Instruments and Risk Management

Financial Instruments

Financial instruments at September 30, 2021 consist of accounts receivable, risk management assets and liabilities, investments in securities, accounts payable, the Paramount Facility and Convertible Debentures. The carrying values of these financial instruments, other than the Convertible Debentures, approximate their fair values. The Convertible Debentures are a compound financial instrument and are described further in Note 6.

Risk Management

Assets

As at	September 30, 2021	December 31, 2020
Electricity swaps – current	467	408
Electricity swaps – long-term	418	–
Risk management asset	885	408

Liabilities

As at	September 30, 2021	December 31, 2020
Interest rate swaps – current	(8,935)	(9,616)
Financial commodity contracts – current	(80,722)	(22,665)
Risk management – current	(89,657)	(32,281)
Interest rate swaps – long-term	(6,411)	(19,441)
Risk management liability	(96,068)	(51,722)

From time-to-time, Paramount enters into derivative financial instruments to manage commodity price, interest rate and foreign currency exchange 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 are as follows:

	Nine months ended September 30, 2021	Twelve months ended December 31, 2020
Fair value, beginning of period	408	6,062
Changes in fair value – financial commodity contract assets	–	31,539
Changes in fair value – electricity swaps	2,064	408
Settlements received – financial commodity contract assets	–	(37,601)
Settlements received – electricity swaps	(1,587)	–
Fair value, end of period	**885**	408

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

	Nine months ended September 30, 2021	Twelve months ended December 31, 2020
Fair value, beginning of period	(51,722)	(8,032)
Changes in fair value – interest rate swaps	6,405	(26,608)
Changes in fair value – financial commodity contract liabilities	(203,905)	(22,665)
Settlements paid – interest rate swaps	7,306	5,583
Settlements paid – financial commodity contract liabilities	145,848	–
Fair value, end of period	**(96,068)**	(51,722)

The Company had the following financial commodity contracts at September 30, 2021:

Instruments	Aggregate notional	Average fixed price	Fair value	Remaining term
Oil – NYMEX WTI Swaps (Sale)	6,000 Bbl/d	CDN$88.45/Bbl	(3,279)	October 2021 – December 2021
Oil – NYMEX WTI Swaps (Sale)	6,000 Bbl/d	CDN$85.88/Bbl	(3,450)	January 2022 – March 2022
Oil – NYMEX WTI Swaps (Sale)	10,000 Bbl/d	US$45.82/Bbl	(33,614)	October 2021 – December 2021
Gas – NYMEX Swaps (Sale)	110,000 MMBtu/d	US$3.37/MMBtu	(32,630)	October 2021 – December 2021
Gas – NYMEX Swaps (Sale)	40,000 MMBtu/d	US$4.15/MMBtu	(7,749)	January 2022 – March 2022
			(80,722)	

Subsequent to September 30, 2021, the Company entered into the following financial commodity contracts:

Instruments	Aggregate notional	Average fixed price	Remaining term
Oil – NYMEX WTI Swaps (Sale)	3,500 Bbl/d	CDN$91.38/Bbl	January 2022 – December 2022
Oil – NYMEX WTI Swaps (Sale)	3,500 Bbl/d	US$75.79/Bbl	January 2022 – December 2022
Oil – NYMEX WTI Costless Collars	7,000 Bbl/d	CDN$82.50/Bbl (Floor) CDN$100.47/Bbl (Ceiling)	January 2022 – December 2022

The Company had the following floating-to-fixed interest rate and electricity swaps at September 30, 2021:

Contract type	Aggregate Notional	Remaining term	Average fixed contract rate	Reference	Fair value
Interest Rate Swaps	$250 million	October 2021 - January 2023	2.3%	CDOR (1)	(5,242)
Interest Rate Swaps	$250 million	October 2021 - January 2026	2.4%	CDOR (1)	(10,104)
Electricity Swaps	5 MWh/d (2)	October 2021 - December 2021	$51.68/MWh	AESO Pool Price (3)	467
Electricity Swaps	5 MWh/d (2)	January 2023 - December 2023	$62.50/MWh	AESO Pool Price (3)	215
Electricity Swaps	5 MWh/d (2)	January 2024 - December 2024	$53.25/MWh	AESO Pool Price (3)	203
					(14,461)

(1) Canadian Dollar Offered Rate.
(2) "MWh" means MegaWatt per hour for the remaining term.
(3) Floating hourly rate established by the Alberta Electric System Operator.

The Company has classified these arrangements as cash flow hedges and applied hedge accounting. At September 30, 2021, $20 million of floating-to-fixed interest rate swaps were de-designated as cash flow hedges due to declines in borrowings under the Paramount Facility. There were no other changes to the critical terms of the hedging relationships and no hedge ineffectiveness was identified on the floating-to-fixed electricity swaps.

In the third quarter of 2021, Paramount entered into floating-to-fixed price swaps to manage exposure to the variable market price of electricity by fixing the underlying AESO Pool Price on a portion of the Company's anticipated power requirements for 2023 and 2024.

13. Revenue By Product

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Natural gas	96,520	39,984	248,634	138,245
Condensate and oil	249,910	88,700	645,415	260,478
Other natural gas liquids	21,716	6,583	51,172	15,291
Royalty and other	991	3,489	3,483	10,005
Royalties	(30,923)	(4,326)	(74,491)	(19,608)
	338,214	134,430	874,213	404,411

14. Other Income (Loss)

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Change in fair value of securities - warrants	–	(3,297)	112	(1,657)
Provisions	–	–	(24,000)	(4,669)
Other	190	(223)	118	(1,796)
	190	(3,520)	(23,770)	(8,122)

For the nine months ended September 30, 2021, the Company recorded provisions of $24.0 million with respect to arrangements with a service provider. The Company has unsettled claims of a greater amount against the same service provider with respect to certain related matters which have not been recognized. The outcome of all of these matters remains uncertain.

15. Consolidated Statement of Cash Flows - Selected Information

Items Not Involving Cash

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Financial commodity contracts	(12,020)	11,901	58,057	(3,341)
Share-based compensation	3,017	5,605	11,111	6,176
Depletion, depreciation and impairment (reversal)	(209,794)	28,960	32,753	259,875
Exploration and evaluation	5,101	–	24,541	18,921
(Gain) loss on sale of oil and gas assets	(32,296)	7,962	(72,104)	8,742
Accretion of asset retirement obligations	10,573	11,002	32,140	32,144
Settlement of dissent payment entitlement	–	–	22,595	–
Foreign exchange	(231)	189	(187)	470
Change in fair value of securities - warrants	–	3,297	(112)	1,657
Deferred income tax	89,132	(18,481)	49,030	74,614
Other	639	698	2,456	2,922
	(145,879)	51,133	160,280	402,180

Supplemental Cash Flow Information

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Interest paid	7,363	15,993	31,299	31,566

Components of Cash and Cash Equivalents

As at	September 30, 2021	December 31, 2020
Cash	1,414	4,590
Cash equivalents	–	–
	1,414	4,590

16. Commitments and Contingencies

Commitments – Physical Sale Contracts

The Company had the following fixed-price physical sales contracts at September 30, 2021:

	Location	Average fixed price	Remaining term
Natural gas – 50,000 GJ/d	AECO	CDN$2.52/GJ	October 2021
Natural gas – 100,000 GJ/d	AECO	CDN$3.27/GJ	October 2021 - December 2021
Natural gas – 40,000 GJ/d	AECO	CDN$4.06/GJ	January 2022 - March 2022

Subsequent to September 30, 2021, the Company entered into the following fixed-price physical sales contracts:

	Location	Average fixed price	Remaining term
Natural gas – 30,000 GJ/d	AECO	CDN$3.54/GJ	April 2022 – October 2022
Condensate – 2,538 Bbl/d	FSPL (1)	WTI + US$3.15/Bbl	December 2021
Condensate – 2,098 Bbl/d	FSPL (1)	WTI + US$3.13/Bbl	January 2022 – March 2022

(1) FSPL refers to condensate delivered into the Fort Saskatchewan Pipeline at Edmonton.

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.

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.

17. Subsequent Events

In November 2021, the Company delivered notices to redeem all $35 million of its Convertible Debentures, effective December 3, 2021 (the "Redemption Date") at a redemption price of 107.5 percent of principal amount.

It is expected that all holders will exercise their right to convert their Convertible Debentures into Common Shares prior to the Redemption Date. If all Convertible Debentures are converted, approximately 5.3 million Common Shares would be issued.

CORPORATE INFORMATION

EXECUTIVE OFFICERS

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

P. R. Kinvig
Chief Financial Officer

B. K. Lee
Executive Vice President, Finance

E. M. Shier
General Counsel 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

DIRECTORS

J. H. T. Riddell (2)
President and Chief Executive Officer and Chairman
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

D. Jungé C.F.A. (2) (4)
Independent Businessman
Bryn Athyn, Pennsylvania

K. Lynch Proctor (1) (4) (5)
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R. M. MacDonald (1) (3) (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

(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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AUDITORS

Ernst & Young LLP
Calgary, Alberta

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
(“POU”)