Paramount Resources Ltd.

Paramount Resources Ltd. Announces First Quarter 2022 Results, Upwardly Revised Guidance, Increased Dividend and Complementary Asset Acquisition

CALGARY, AB, May 4, 2022 /CNW/ - Paramount Resources Ltd. ("Paramount" or the "Company") (TSX: POU) is pleased to announce strong first quarter 2022 financial and operating results, the acceleration of development activities at Karr supporting increased production in 2023 and beyond and a highly complementary $40 million Duvernay acquisition in its Willesden Green core area. Paramount is also pleased to announce that it is increasing its regular monthly dividend from $0.08 per class A common share ("Common Share") to $0.10 per Common Share beginning May 2022.

HIGHLIGHTS

- First quarter 2022 sales volumes averaged 82,137 Boe/d (45% liquids), in-line with expectations.(1)
  - Sales volumes at Karr averaged 38,611 Boe/d (51% liquids).
  - Sales volumes at Wapiti averaged 16,126 Boe/d (59% liquids).
- Cash from operating activities was $175 million ($1.25 per basic share) in the first quarter. Adjusted funds flow was $238 million ($1.70 per basic share). Free cash flow was $103 million ($0.74 per basic share).(2)
- First quarter capital expenditures totaled $117 million and were predominantly focused on drilling and completion activities at Karr and Wapiti as well as in the Kaybob region.
- Paramount realized cash proceeds of approximately $51 million from the sale of a portion of its investments in securities in the first quarter.
- Net debt was reduced by approximately $96 million quarter-over-quarter to $361 million at March 31, 2022, including drawings under the Company's credit facility of $305 million. Net debt does not account for the $479 million carrying value of the Company's investments in securities as at March 31, 2022. (3)
- Paramount now expects to achieve its net debt target of about $300 million by mid-year, earlier than previously forecast, even after accounting for the $40 million Willesden Green acquisition.
- Abandonment and reclamation expenditures in the first quarter totaled $15 million, net of $5 million in funding under the Alberta Site Rehabilitation Program ("ASRP"). A total of 63 wells were abandoned in the quarter, including 36 under the Company's ongoing area-based closure program at Zama.
- In late April, the Company acquired Duvernay lands and production directly offsetting its existing 61,000 net acre position in the Willesden Green area of Alberta for approximately $40 million in cash prior to adjustments. The acquisition is accretive on all key metrics and more than doubles Paramount's land position and internally estimated drilling locations in the area, setting the stage for more efficient future development and potential infrastructure synergies. Current production from the acquisition is approximately 1,300 Boe/d (49% liquids).
- In May, Paramount increased the capacity of its bank credit facility to $1.0 billion and extended the maturity date to May 3, 2026. The capacity of the credit facility can be further increased by up to $250 million pursuant to an accordion feature, subject to incremental lender commitments.

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(1) 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. 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, light and medium crude oil and tight oil. See also "Oil and Gas Measures and Definitions" in the Advisories section.
(2) Adjusted funds flow and free cash flow are capital management measures used by Paramount. Adjusted funds flow per basic share and free cash flow per basic share are supplementary financial measures. Refer to the "Specified Financial Measures" section for more information on these measures.
(3) Net debt is a capital management measure used by Paramount. Refer to the "Specified Financial Measures" section for more information on this measure.

INCREASED DIVIDEND

Paramount's Board of Directors has approved a 25% increase in the Company's regular monthly dividend from $0.08 to $0.10 per Common Share. The first increased dividend will be payable on May 31, 2022 to shareholders of record on May 16, 2022. The dividend will be designated as an "eligible dividend" for Canadian income tax purposes.

UPDATED 2022 GUIDANCE AND PRELIMINARY 2023 BUDGET

The Company's planned 2022 capital expenditures have been upwardly revised by $20 million to a range of between $520 million and $560 million. The additional capital expenditures will be used to accelerate the drilling of a five-well pad at Karr from 2023 into late 2022 to facilitate further production growth in 2023. 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. The Company continues to budget $33 million of abandonment and reclamation expenditures in 2022, net of approximately $8 million in funding under the ASRP.

Paramount is reaffirming its 2022 annual average sales volume guidance of between 91,000 Boe/d and 95,000 Boe/d (46% liquids).

- First half 2022 sales volumes are expected to average between 81,000 Boe/d and 85,000 Boe/d (44% liquids).
- Second half 2022 sales volumes are expected to average between 101,000 Boe/d and 105,000 Boe/d (47% liquids).

The Company is increasing its forecast of 2022 free cash flow from approximately $590 million to approximately $710 million to reflect higher commodity price assumptions and its updated capital expenditure plan.[1]

(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) $7 million in geological and geophysical expenses, (iv) realized pricing of $72.55/Boe (US$97.07/Bbl WTI, US$6.34/MMBtu NYMEX, $5.34/GJ AECO), (v) a $US/$CDN exchange rate of $0.793, (vi) royalties of $12.40/Boe, (vii) operating costs of $11.30/Boe and (viii) transportation and processing costs of $4.10/Boe.

The Company's 2022 capital program, targeted net debt reduction and regular monthly dividend would remain fully funded down to an average WTI price of about US$50.00/Bbl over the last three quarters of 2022. [1]

Paramount's anticipated 2023 capital expenditure budget, based on preliminary planning and current market conditions, has been upwardly revised by $60 million at the midpoint to a range of between $540 million and $580 million. The additional capital expenditures will largely be focused on accelerating development activities at Karr to grow production by approximately 4,000 Boe/d in 2023 to a range of 45,000 Boe/d to 49,000 Boe/d and set the stage for a new production plateau range of 50,000 Boe/d to 54,000 Boe/d in 2024.

The Company expects that a capital program in this range will result in 2023 average sales volumes of 105,000 Boe/d to 110,000 Boe/d (47% liquids), 6,500 Boe/d higher than previous estimates and a 15% increase at midpoint from forecast average 2022 sales volumes.

Paramount is updating its estimate of 2023 free cash flow that would be expected from such a capital program from approximately $580 million to approximately $820 million to reflect higher production and commodity price assumptions.[2]

UPDATED FIVE-YEAR OUTLOOK

The Company is updating its previously provided five-year outlook to reflect revised capital and production expectations and recent commodity prices. Paramount now anticipates cumulative free cash flow through to the end of 2026 of approximately $4.1 billion, up from $3.3 billion. The Company now anticipates annual capital expenditures of approximately $550 million (up from $500 million) and a compound annual production growth rate of approximately 7% (up from 5%) through the period.[3]

DELIVERING ON FREE CASH FLOW PRIORITIES

Paramount's free cash flow priorities are: (i) the achievement of its net debt target of about $300 million and the maintenance of conservative leverage levels thereafter, (ii) shareholder returns and (iii) incremental growth. Paramount has and will continue to deliver on these priorities.

- The Company expects to achieve its net debt target of about $300 million by mid-year 2022. At this level, year-end 2022 net debt to adjusted funds flow would be less than 0.3x.[4]
- Paramount has increased shareholder returns by implementing a regular monthly dividend in July 2021 of $0.02 per share and increasing it three times to $0.10 per share beginning in May 2022. The Company retains the flexibility to make repurchases of shares under its normal course issuer bid.
- The Company has allocated incremental capital to its highest risk-adjusted rate of return organic growth opportunities and to accretive acquisitions, adding to the significant free cash flow and production growth described in the five-year outlook.

(1) Assuming no changes to the other free cash flow forecast assumptions for 2022.
(2) The revised free cash flow estimate is based on the following assumptions for 2023: (i) the midpoint of stated capital spending and production, (ii) $40 million in abandonment and reclamation costs, (iii) $7 million in geological and geophysical expenses, (iv) realized pricing of $63.80/Boe (US$87.88/Bbl WTI, US$5.04/MMBtu NYMEX, $4.48/GJ AECO), (v) a $US/$CDN exchange rate of $0.794, (vi) royalties of $12.05/Boe, (vii) operating costs of $10.60/Boe and (vii) transportation and processing costs of $3.80/Boe.
(3) The five-year outlook is based on preliminary planning and current market conditions and is subject to change. 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) approximately $7 million in annual geological and geophysical expenses, (iv) strip commodity prices and foreign exchange rates as at April 21, 2022, and (v) internal management estimates of future royalties, operating costs, transportation and processing costs and, in 2026, cash taxes.
(4) Assuming 2022 adjusted funds flow in excess of $1 billion.

REVIEW OF OPERATIONS

GRANDE PRAIRIE REGION

Grande Prairie Region sales volumes and netbacks are summarized below:

	Q1 2022	Q4 2021	*% Change*
Sales volumes			
Natural gas (MMcf/d)	**152.5**	158.9	*(4)*
Condensate and oil (Bbl/d)	**26,048**	26,278	*(1)*
Other NGLs (Bbl/d)	**3,267**	3,276	-
Total (Boe/d)	**54,737**	56,035	*(2)*
% liquids	***54%***	*53%*	

Netback (1)	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*Change in $ millions (%)*
Natural gas revenue (2)	**72.1**	***5.25***	71.5	*4.89*	*1*
Condensate and oil revenue	**277.1**	***118.21***	230.5	*95.37*	*20*
Other NGLs revenue	**18.1**	***61.47***	16.6	*54.97*	*9*
Royalty and other revenue (3)	**10.7**	**-**	-	-	*NM*
Petroleum and natural gas sales	**378.0**	***76.74***	318.6	*61.81*	*19*
Royalties	**(61.4)**	***(12.46)***	(39.8)	*(7.74)*	*54*
Operating expense	**(53.7)**	***(10.89)***	(54.9)	*(10.64)*	*(2)*
Transportation and NGLs processing	**(23.2)**	***(4.73)***	(19.0)	*(3.68)*	22
	239.7	***48.66***	204.9	*39.75*	*17*

(1) "Netback" is a Non-GAAP financial measure. When presented on a $/Boe or $/Mcf basis, each of the components of Netback is a supplementary financial measure and Netback is a non-GAAP ratio. Refer to the "Specified Financial Measures" section for more information on these measures.
(2) Natural gas revenue presented as $/Mcf.
(3) In the first quarter of 2022, royalty and other revenue includes $10.6 million in respect of a contingent business interruption insurance claim. Refer to Note 12 in the unaudited Interim Condensed Consolidated Financial Statements as at and for the three months ended March 31, 2022.
NM means not meaningful.

KARR AREA

Karr sales volumes and netbacks are summarized below:

	Q1 2022	Q4 2021	*% Change*
Sales volumes			
Natural gas (MMcf/d)	**113.3**	124.0	*(9)*
Condensate and oil (Bbl/d)	**17,246**	18,521	*(7)*
Other NGLs (Bbl/d)	**2,475**	2,449	*1*
Total (Boe/d)	**38,611**	41,629	*(7)*

% liquids		***51%***		*50%*	
Netback (1)	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*Change in $ millions (%)*
Natural gas revenue (2)	**53.1**	***5.21***	55.2	*4.84*	*(4)*
Condensate and oil revenue	**182.4**	***117.56***	161.3	*94.67*	*13*
Other NGLs revenue	**14.4**	***64.60***	13.1	*58.20*	*10*
Royalty and other revenue	**0.1**	**-**	-	-	*NM*
Petroleum and natural gas sales	**250.0**	***71.95***	229.6	*59.96*	*9*
Royalties	**(54.0)**	***(15.52)***	(35.7)	*(9.32)*	*51*
Operating expense	**(35.2)**	***(10.14)***	(36.0)	*(9.38)*	*(2)*
Transportation and NGLs processing	**(16.1)**	***(4.65)***	(14.0)	*(3.68)*	15
	144.7	***41.64***	143.9	*37.58*	*1*

(1) "Netback" is a Non-GAAP financial measure. When presented on a $/Boe or $/Mcf basis, each of the components of Netback is a supplementary financial measure and Netback is a non-GAAP ratio. Refer to the "Specified Financial Measures" section for more information on these measures.
(2) Natural gas revenue presented as $/Mcf.
NM means not meaningful.

First quarter 2022 sales volumes at Karr averaged 38,611 Boe/d (51% liquids) compared to 41,629 Boe/d (50% liquids) in the fourth quarter of 2021. Sales volumes were lower primarily due to natural declines. Several short, unplanned curtailments at third-party operated facilities in the first quarter, all of which have now been resolved, also contributed to the reduction.

The first seven wells at the 16-17 pad came on production ahead of schedule and under budget with preliminary drilling, completion, equipping and tie-in ("DCET") costs averaging $6.9 million per well. Average gross peak 30-day production per well was 1,395 Boe/d (3.6 MMcf/d of shale gas and 802 Bbl/d of NGLs) with an average CGR of 225 Bbl/MMcf.(1) The Company continues to strive for improved efficiencies in its development activities to mitigate inflationary pressures on DCET costs without compromising completion effectiveness or health, safety and environmental performance. The 16-17 pad, as well as the Wapiti 9-22 pad, are the Company's first two pads to have been equipped with instrument air to operate all pneumatically driven controllers. Paramount plans to equip new pads with instrument air where possible to minimize methane emissions from its operations.

Second quarter activities at Karr include completing the drilling of the remaining five wells at the 16-17 pad. These wells are expected to be brought onstream in the third quarter. Second quarter sales volumes are expected to be impacted by a 16-day full field outage for scheduled turnaround activities at third-party midstream facilities.

In the second half of 2022, the Company plans to drill, complete, tie-in and bring on production the four-well 1-2 North pad and commence drilling the five-well 4-2 South pad. In addition, the Company is accelerating the drilling of the five-well 4-2 North pad into the fourth quarter. Paramount plans to bring onstream additional gas lift compression in the year to support liquids production and continue to build out infrastructure to debottleneck future production.

(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.

WAPITI AREA

Wapiti sales volumes and netbacks are summarized below:

	Q1 2022	Q4 2021	*% Change*
Sales volumes			
Natural gas (MMcf/d)	**39.2**	34.9	*12*
Condensate and oil (Bbl/d)	**8,802**	7,757	*13*
Other NGLs (Bbl/d)	**792**	827	*(4)*
Total (Boe/d)	**16,126**	14,406	*12*

% liquids		*59%*		*60%*	*Change in $*
Netback (1)	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	*millions (%)*
Natural gas revenue (2)	**19.0**	***5.39***	16.3	*5.07*	*17*
Condensate and oil revenue	**94.7**	***119.49***	69.2	*97.03*	*37*
Other NGLs revenue	**3.7**	***51.67***	3.5	*45.43*	*6*
Royalty and other revenue (3)	**10.6**	**-**	-	-	*NM*
Petroleum and natural gas sales	**128.0**	***88.20***	89.0	*67.15*	*44*
Royalties	**(7.4)**	***(5.13)***	(4.1)	*(3.18)*	*80*
Operating expense	**(18.5)**	***(12.69)***	(18.9)	*(14.26)*	*(2)*
Transportation and NGLs processing	**(7.1)**	***(4.92)***	(5.0)	*(3.69)*	42
	95.0	***65.46***	61.0	*46.02*	*56*

(1) "Netback" is a Non-GAAP financial measure. When presented on a $/Boe or $/Mcf basis, each of the components of Netback is a supplementary financial measure and Netback is a non-GAAP ratio. Refer to the "Specified Financial Measures" section for more information on these measures.
(2) Natural gas revenue presented as $/Mcf.
(3) In the first quarter of 2022, royalty and other revenue includes $10.6 million in respect of a contingent business interruption insurance claim. Refer to Note 12 in the unaudited Interim Condensed Consolidated Financial Statements as at and for the three months ended March 31, 2022.

NM means not meaningful.

First quarter 2022 sales volumes at Wapiti averaged 16,126 Boe/d (59% liquids) compared to 14,406 Boe/d (60% liquids) in the fourth quarter of 2021 as a result of new production from the seven-well 9-22 pad that came onstream between late in the fourth quarter of 2021 and the first quarter of 2022. The increase in sales volumes was achieved despite three unplanned outages at the Wapiti Plant that resulted in approximately three weeks of downtime and approximately 5,100 Boe/d of lost production in the quarter.

Royalty and other revenue for the three months ended March 31, 2022 includes $10.6 million in respect of the Company's business interruption claim arising from outages at the Wapiti Plant in 2020 and 2021.

Despite operational challenges associated with outages at the Wapiti Plant, initial results from the seven-well 9-22 pad have been encouraging, averaging gross peak 30-day production per well of 1,503 Boe/d (4.0 MMcf/d of shale gas and 840 Bbl/d of NGLs) with an average CGR of 211 Bbl/MMcf.(1)

Drilling operations at the eight-well 8-22 pad that commenced in late 2021 are now complete. The pad is the Company's first where all wells have been configured as monobores. This delivers a cost advantage compared to conventional multiple casing wells due to lower steel requirements and higher pumping efficiencies.

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 12% and liquids sales volumes are lower by approximately 2% 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.

Second quarter sales volumes are anticipated to increase as all eight wells on the 8-22 pad are brought onstream. Additional second quarter activities include the drilling of eight wells at the 6-32 pad, which is forecast to be brought on production in the third quarter, and the commencement of drilling operations at the eight well 16-15 pad, which is forecast to be brought on production in early 2023. The Company also plans to commence the drilling of the eight well 8-15 pad later in the year.

KAYBOB REGION

Kaybob Region sales volumes averaged 20,726 Boe/d (28% liquids) in the first quarter compared to 21,725 Boe/d (29% liquids) in the fourth quarter of 2021. The decrease in production is primarily attributable to natural declines.

Development commenced at the Company's two Duvernay assets at Kaybob Smoky and Kaybob North. Drilling operations at the four well 10-35 pad at Kaybob Smoky were recently completed on time with preliminary drilling cost estimates coming in approximately 7% under budget. The Company plans to commence completion operations in the second quarter and expects all four wells to be onstream in the third quarter. The Company also plans to expand its 100% owned and operated 6-16 facility in 2022. Drilling of the two remaining wells at the three well Kaybob North 12-21 pad have recently commenced. The Company plans to bring all three wells onstream in the fourth quarter.

In addition to the activities at Kaybob Smoky and Kaybob North, Paramount is advancing a number of other high return opportunities in the Kaybob Region. The first (1.0 net) of four (2.5 net) Montney gas wells in the Kaybob Presley area planned for 2022 was drilled, completed and brought onstream in the first quarter and a second (0.5 net) well was drilled in the quarter and is forecast to come onstream in the second quarter. The remaining two (1.0 net) wells at Kaybob Presley are expected to be drilled, completed and brought onstream by the fourth quarter. The two (2.0 net) Kaybob Gething oil wells planned for 2022 have completed drilling operations and are forecast to come onstream in the third quarter. In addition, one (1.0 net) Kaybob Montney Oil well is planned to be drilled, completed and brought onstream over the second and third quarters.

CENTRAL ALBERTA AND OTHER REGION

Central Alberta and Other Region sales volumes averaged 6,674 Boe/d (22% liquids) in the first quarter compared to 7,505 Boe/d (26% liquids) in the fourth quarter of 2021. The decrease in production is primarily attributable to natural declines.

The recently completed acquisition at Willesden Green adds over 90,000 net acres (after deducting near-term expiries) to Paramount's land position and approximately 200 internally estimated Duvernay drilling locations.[(1)] Prior to the acquisition, the Company's preliminary development plans for Willesden Green targeted a full field production plateau of approximately 20,000 Boe/d, which could be sustained for over 15 years based on approximately 180 internally estimated Duvernay drilling locations. Paramount's five-year outlook includes capital to advance development of the asset with production expected to begin ramping up in 2025/26. The incremental drilling inventory provided by the acquisition allows for the potential to expand development plans to increase the ultimate targeted plateau production level. The Company had already initiated an engineering design study for the expansion of its majority owned Leafland gas plant in the area as part of its 2022 capital program and will now incorporate the acquisition into the study to optimize full field development plans for Willesden Green. Paramount continues to review its plans for Willesden Green, including the targeted plateau production level, capital allocation and pace of development.

(1) See also "Oil and Gas Measures and Definitions" in the Advisories section for additional information respecting internally estimated drilling locations.

HEDGING

Paramount has hedged approximately 31% of its remaining 2022 forecast production to provide greater free cash flow certainty. The Company's current hedging position is summarized below:

	Type [(1)]	Q2 2022	Q3 2022	Q4 2022	Q1 2023	Average Price [(2)]
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	3,500	3,500	3,500	–	US$75.79/Bbl
Oil – WTI Swaps (Sale) (Bbl/d)	Financial	3,500	3,500	3,500	–	CDN$91.38/Bbl
Oil – WTI Collars (Bbl/d)	Financial	7,000	7,000	7,000	–	CDN$82.50/Bbl (Floor) CDN$100.47/Bbl (Ceiling)
Sweet Crude Oil – Basis (Sale) (Bbl/d)	Physical	5,186	–	–	–	WTI - US$2.15/Bbl
Gas – NYMEX Swaps (Sale) (MMBtu/d)	Financial	30,000	–	–	–	US$4.62/MMBtu
Gas – NYMEX Swaps (Sale) (MMBtu/d)	Financial	–	30,000	–	–	US$4.67/MMBtu
Gas – NYMEX Swaps (Sale) (MMBtu/d)	Financial	–	–	3,370	–	US$4.91/MMBtu
Gas – AECO fixed price (GJ/d)	Physical	80,000	80,000	26,957	–	CDN$3.78/GJ
Gas – Dawn fixed price (MMBtu/d)	Physical	20,000	20,000	6,739	–	US$4.03/MMBtu
Fx – CDN/USD Forwards (US$MM/Month)	Forwards	$15	$20	$20	$10	1.2804 C$ / US$
Fx – CDN/USD Collars (US$MM/Month)	Financial	$5	$5	$3.3	–	1.25 C$ / US$ (Floor) 1.30 C$ / US$ (Ceiling)
Fx – CDN/USD Swaps (US$MM/Month)	Financial	$6.7	$10	$10	$10	1.2888 C$ / US$

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

ANNUAL GENERAL MEETING

Paramount will hold its annual general meeting of shareholders in a virtual-only format accessible at https://meetnow.global/MD9YA2M on Wednesday, May 4, 2022 at 10:30 a.m. (Calgary time).

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, 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 first quarter 2022 results, including Management's Discussion and Analysis and the Company's Consolidated Financial Statements, can be obtained on SEDAR at www.sedar.com or on Paramount's website at https://www.paramountres.com/investors/financial-shareholder-reports.

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

FINANCIAL AND OPERATING RESULTS (1)

($ millions, except as noted)	Q1 2022	Q4 2021	Q1 2021
Net income (loss)	**16.6**	101.0	**(82.5)**
per share – basic ($/share)	***0.12***	*0.75*	***(0.62)***
per share – diluted ($/share)	***0.11***	*0.70*	***(0.62)***
Cash from operating activities	**174.9**	191.8	**81.3**
per share – basic ($/share)	***1.25***	*1.42*	***0.61***
per share – diluted ($/share)	***1.20***	*1.33*	***0.61***
Adjusted funds flow	**237.8**	174.6	**90.9**
per share – basic ($/share)	***1.70***	*1.29*	***0.69***
per share – diluted ($/share)	***1.63***	*1.21*	***0.69***
Free cash flow	**103.4**	99.0	**21.6**
per share – basic ($/share)	***0.74***	*0.73*	***0.16***
per share – diluted ($/share)	***0.71***	*0.69*	***0.16***
Total assets	**4,095.5**	3,885.1	**3,583.1**
Long-term debt	**302.6**	386.3	**712.7**
Net debt	**361.2**	456.7	**761.7**
Common shares outstanding *(millions)* (2)	**140.0**	139.2	**132.8**
Sales volumes (3)			
Natural gas (MMcf/d)	**272.9**	284.8	**273.1**
Condensate and oil (Bbl/d)	**31,375**	32,342	**29,854**
Other NGLs (Bbl/d)	**5,276**	5,462	**5,170**
Total (Boe/d)	**82,137**	85,265	**80,540**
% liquids	***45%***	*44%*	***43%***
Grande Prairie Region (Boe/d)	**54,737**	56,035	**47,385**
Kaybob Region (Boe/d)	**20,726**	21,725	**24,938**
Central Alberta & Other Region (Boe/d)	**6,674**	7,505	**8,217**
Total (Boe/d)	**82,137**	85,265	**80,540**

Netback		*$/Boe* (4)		*$/Boe* (4)		*$/Boe* (4)
Natural gas revenue	**127.1**	***5.18***	124.7	*4.76*	**77.3**	***3.14***
Condensate and oil revenue	**331.9**	***117.53***	281.1	*94.46*	**185.9**	***69.20***
Other NGLs revenue	**29.3**	***61.64***	27.4	*54.61*	**15.0**	***32.29***
Royalty and other revenue	**11.3**	**—**	1.3	—	**1.9**	**—**
Petroleum and natural gas sales	**499.6**	***67.59***	434.5	*55.40*	**280.1**	***38.64***
Royalties	**(76.2)**	***(10.31)***	(52.5)	*(6.69)*	**(18.6)**	***(2.57)***
Operating expense	**(89.2)**	***(12.07)***	(91.0)	*(11.61)*	**(84.3)**	***(11.63)***
Transportation and NGLs processing	**(31.3)**	***(4.24)***	(26.1)	*(3.33)*	**(27.9)**	***(3.84)***
Sales of commodities purchased (5)	**48.8**	***6.59***	22.1	*2.82*	**8.6**	***1.18***

Commodities purchased [5]	**(49.1)**	***(6.64)***	(22.3)	*(2.85)*	**(8.8)**	***(1.21)***
Netback	**302.6**	***40.92***	264.7	*33.74*	**149.1**	***20.57***
Risk management contract settlements	**(49.7)**	***(6.72)***	(72.4)	*(9.23)*	**(32.7)**	***(4.51)***
Netback including risk management contract settlements	**252.9**	***34.20***	192.3	*24.51*	**116.4**	***16.06***
Capital expenditures						
Grande Prairie Region	**76.8**		57.7		**51.3**	
Kaybob Region	**31.1**		3.8		**5.0**	
Central Alberta & Other Region	**0.1**		2.6		**1.2**	
Corporate	**9.0**		1.6		**1.8**	
Total	**117.0**		65.7		**59.3**	
Asset retirement obligations settlements	**14.8**		7.0		**8.4**	

(1) Adjusted funds flow, free cash flow and net debt are capital management measures used by Paramount. Netback and netback including risk management contract settlements are non-GAAP financial measures. Netback and Netback including risk management contract settlements presented on a $/Boe or $/Mcf basis are non-GAAP ratios. Each measure, other than net income, that is presented on a per share, $/Mcf or $/Boe basis is a supplementary financial measure. Refer to the "Specified Financial Measures" section for more information on these measures. Prior period free cash flow has been reclassified to conform with the current year's presentation.
(2) Common shares are presented net of shares held in trust under the Company's restricted share unit plan: Q1 2022: 1.5 million; Q4 2021: 1.5 million; Q1 2021: 1.9 million.
(3) Refer to the Product Type Information section of this document for a complete breakdown of sales volumes for applicable periods by specific product type.
(4) Natural gas revenue presented as $/Mcf.
(5) Sales of commodities purchased and commodities purchased are treated as corporate items and not allocated to individual regions or properties.

PRODUCT TYPE INFORMATION

This press release refers to sales volumes of "liquids", "natural gas", "condensate and oil" and "other NGLs". "Liquids" means 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. 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		
	Q1 2022	**Q4 2021**	**Q1 2021**	**Q1 2022**	**Q4 2021**	**Q1 2021**	**Q1 2022**	**Q4 2021**	**Q1 2021**
Shale gas (MMcf/d)	**213.1**	220.4	197.8	**151.4**	156.5	120.6	**35.7**	35.6	42.1
Conventional natural gas (MMcf/d)	**59.8**	64.4	75.3	**1.1**	2.4	2.0	**53.6**	56.8	65.8
Natural gas (MMcf/d)	**272.9**	284.8	273.1	**152.5**	158.9	122.6	**89.3**	92.4	107.9
Condensate (Bbl/d)	**29,098**	29,797	27,017	**26,042**	26,272	23,974	**2,130**	2,184	2,611
Other NGLs (Bbl/d)	**5,276**	5,462	5,170	**3,267**	3,276	2,984	**1,558**	1,788	1,677
NGLs (Bbl/d)	**34,374**	35,259	32,187	**29,309**	29,548	26,958	**3,688**	3,972	4,288
Tight oil (Bbl/d)	**403**	497	479	**-**	-	-	**322**	355	342
Light and medium crude oil (Bbl/d)	**1,874**	2,048	2,358	**6**	6	-	**1,832**	2,000	2,321
Crude oil (Bbl/d)	**2,277**	2,545	2,837	**6**	6	-	**2,154**	2,355	2,663
Total (Boe/d)	**82,137**	85,265	80,540	**54,737**	56,035	47,385	**20,726**	21,725	24,938

	Central and Other Region			Karr			Wapiti		
	Q1 2022	**Q4 2021**	**Q1 2021**	**Q1 2022**	**Q4 2021**	**Q1 2021**	**Q1 2022**	**Q4 2021**	**Q1 2021**
Shale gas (MMcf/d)	**26.0**	28.2	35.1	**112.8**	122.5	89.1	**38.6**	34.0	31.5
Conventional natural gas (MMcf/d)	**5.1**	5.3	7.5	**0.5**	1.5	1.1	**0.6**	0.9	0.9
Natural gas (MMcf/d)	**31.1**	33.5	42.6	**113.3**	124.0	90.2	**39.2**	34.9	32.4
Condensate (Bbl/d)	**926**	1,341	433	**17,246**	18,521	16,095	**8,796**	7,751	7,879
Other NGLs (Bbl/d)	**451**	398	509	**2,475**	2,449	2,108	**792**	827	876

NGLs (Bbl/d)	**1,377**	1,729	942	**19,721**	20,970	18,203	**9,588**	8,578	8,755
Tight oil (Bbl/d)	**81**	142	136	**-**	-	-	**-**	-	-
Light and medium crude oil (Bbl/d)	**36**	42	37	**-**	-	-	**6**	6	-
Crude oil (Bbl/d)	**117**	184	173	**-**	-	-	**6**	6	-
Total (Boe/d)	**6,674**	7,505	8,217	**38,611**	41,629	33,230	**16,126**	14,406	14,155

The Company forecasts that 2022 sales volumes will average between 91,000 Boe/d and 95,000 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 101,000 Boe/d and 105,000 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).

SPECIFIED FINANCIAL MEASURES

Non-GAAP Financial Measures

Netback and netback including risk management contract settlements are non-GAAP financial measures. These measures are not standardized measures under IFRS and might not be comparable to similar financial measures presented by other issuers. These measures should not be considered in isolation or construed as alternatives to their most directly comparable measure disclosed in the Company's primary financial statements or other measures of financial performance calculated in accordance with IFRS.

Netback equals petroleum and natural gas sales (the most directly comparable measure disclosed in the Company's primary financial statements) plus sales of commodities purchased less royalties, operating expense, transportation and NGLs processing expense and commodities purchased. Netback is used by investors and Management to compare the performance of the Company's producing assets between periods.

Netback including risk management contract settlements equals netback after including (or deducting) risk management contract settlements received (paid). Netback including risk management contract settlements is used by investors and Management to assess the performance of the producing assets after incorporating Management's risk management strategies.

Refer to the table under the heading "Financial and Operating Results" in this press release for the calculation of netback and netback including risk management contract settlements for the three months ended March 31, 2022 and 2021.

Non-GAAP Ratios

Netback and netback including risk management contract settlements presented on a $/Boe basis are non-GAAP ratios as they each have a non-GAAP financial measure (netback and netback including risk management contract settlements, respectively) as a component. These measures are not standardized measures under IFRS and might not be comparable to similar financial measures presented by other issuers. These measures should not be considered in isolation or construed as alternatives to their most directly comparable measure disclosed in the Company's primary financial statements or other measures of financial performance calculated in accordance with IFRS.

Netback on a $/Boe basis is calculated by dividing netback for the applicable period by the total production during the period in Boe. Netback including risk management contract settlements on a $/Boe basis is calculated by dividing netback including risk management contract settlements for the applicable period by the total production during the period in Boe. These measures are used by investors and Management to assess netback and netback including risk management contract settlements on a unit of production basis.

Capital Management Measures

Adjusted funds flow, free cash flow and net debt are capital management measures that Paramount utilizes in managing its capital structure. These measures are not standardized measures and therefore may not be comparable with the calculation of similar measures by other entities. Refer to Note 15 – Capital Structure in the unaudited Interim Condensed Consolidated Financial Statements of Paramount as at and for the three months ended March 31, 2022 for: (i) a description of the composition and use of these measures, (ii) reconciliations of adjusted funds flow and free cash flow to cash from operating activities, the most directly comparable measure disclosed in the Company's primary financial statements, for the three months ended March 31, 2022 and 2021 and (iii) a calculation of net debt as at March 31, 2022 and December 31, 2021.

Supplementary Financial Measures

This press release contains supplementary financial measures expressed as: (i) cash from operating activities, adjusted funds flow and free cash flow on a per share – basic and per share – diluted basis and (ii) revenue, petroleum and natural gas sales, royalties, operating expenses, transportation and NGLs processing expenses, sales of commodities purchased and commodities purchased on a $/Bbl, $/Mcf or $/Boe basis.

Cash from operating activities, adjusted funds flow and free cash flow on a per share – basic basis are calculated by dividing cash from operating activities, adjusted funds flow or free cash flow, as applicable, over the referenced period by the weighted average basic shares outstanding during the period determined under IFRS. Cash from operating activities, adjusted funds flow and free cash flow on a per share – diluted basis are calculated by dividing cash from operating activities, adjusted funds flow or free cash flow, as applicable, over the referenced period by the weighted average diluted shares outstanding during the period determined under IFRS.

Revenue, petroleum and natural gas sales, royalties, operating expenses, transportation and NGLs processing expense, sales of commodities purchased and commodities purchased on a $/Bbl, $/Mcf or $/Boe basis are calculated by dividing the revenue, petroleum and natural gas sales, royalties, operating expenses, transportation and NGLs processing expense, sales of commodities purchased or commodities purchased, as applicable, over the referenced period by the aggregate applicable units of production (Bbl, Mcf or Boe) during such period.

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:

- the expectation that the Company will achieve its net debt target of about $300 million mid-year 2022 and potential net debt to adjusted funds flow at year-end;
- planned abandonment and reclamation expenditures and activities in 2022 and 2023;
- planned capital expenditures in 2022;
- forecast sales volumes for 2022 and certain periods therein;
- forecast free cash flow in 2022;
- preliminary anticipated capital expenditures in 2023 and the resulting expected 2023 average sales volumes and free cash flow;
- expected production growth at Karr in 2023 and the potential range of plateau production at Karr in 2024;
- the Company's five-year outlook for capital spending, annual production growth rate and cumulative free cash flow;
- planned exploration, development and production activities, including the expected timing of drilling, completing and bringing new wells on production;
- the expectation that second quarter sales volumes at Karr will be impacted by a 16-day full field outage for scheduled turnaround activities at third-party midstream facilities;
- expected increases in sales volumes at Wapiti in the second quarter of 2022;
- internally estimated drilling locations and potential plateau production volumes at Willesden Green and the time period over which plateau production volumes may be maintained; and
- the payment of future dividends under the Company's monthly dividend program.

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;
- the impact of the COVID-19 pandemic on the Company;
- the ability to realize expected cost savings;
- royalty rates, taxes and capital, operating, general & administrative and other costs;
- foreign currency exchange rates, interest rates and the rate of inflation;
- 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, materials, services 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 natural gas and liquids successfully to current and new customers;
- the ability of Paramount and its industry partners to obtain drilling success (including in respect of anticipated production volumes, reserves additions, liquids yields and resource recoveries) and operational improvements, efficiencies and results consistent with expectations;
- the timely receipt of required governmental and regulatory approvals;
- the receipt of benefits under government programs;
- the application of regulatory requirements respecting abandonment and reclamation; and
- anticipated timelines and budgets being met in respect of drilling programs and other operations (including well completions and tie-ins, the construction, commissioning and start-up of new and expanded facilities, including third-party facilities, and facility turnarounds and maintenance).

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;
- 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, interest rates and the rate of inflation;
- the uncertainty of estimates and projections relating to future revenue, free cash flow, production, reserve 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, materials, services and personnel in a timely manner and at an acceptable cost, including the potential effects of inflation and supply chain disruptions;
- 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 obtain and maintain leases and licenses;
- the effects of weather and other factors including wildlife and environmental restrictions which affect field operations and access;
- uncertainties as to 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, 2021, 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 2022 and future periods, 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.

Oil and Gas Measures and Definitions

Liquids		**Natural Gas**	
Bbl	Barrels	GJ	Gigajoules
Bbl/d	Barrels per day	GJ/d	Gigajoules per day
MBbl	Thousands of barrels	MMBtu	Millions of British Thermal Units
NGLs	Natural gas liquids	MMBtu/d	Millions of British Thermal Units per day
Condensate	Pentane and heavier hydrocarbons	Mcf	Thousands of cubic feet
		MMcf	Millions of cubic feet
Oil Equivalent		MMcf/d	Millions of cubic feet per day
Boe	Barrels of oil equivalent	AECO	AECO-C reference price
MBoe	Thousands of barrels of oil equivalent	WTI	West Texas Intermediate
MMBoe	Millions of barrels of oil equivalent		
Boe/d	Barrels of oil equivalent per day		

This press release contains disclosures expressed as "Boe", "$/Boe", "MBoe", "MMBoe" 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 three months ended March 31, 2022, the value ratio between crude oil and natural gas was approximately 27:1. 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.

This press release contains information respecting Paramount's internal estimate of Duvernay drilling locations at Willesden Green. The referenced drilling locations represent future potential undeveloped gross locations as estimated effective December 31, 2021 by internal qualified reserves evaluators from Paramount. The referenced drilling locations were determined by Paramount's internal evaluators based on, among other matters, their assessment of available reservoir, geological and technical information, the economic thresholds necessary for development and potential future development plans. There is no certainty that the Company will drill any of the identified future potential undeveloped locations and there is no certainty that such locations will result in any reserves or production. The locations on which the Company will actually drill wells, including the number and timing thereof, will be dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil, NGLs and natural gas prices, costs, actual drilling results, additional reservoir, geological and technical information that is obtained and other factors. While certain of the estimated undeveloped locations have been de-risked by drilling existing wells in relative close proximity to such locations, many of the locations are further away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty as to whether wells will be drilled in such locations, and if wells are drilled in such locations there is more uncertainty that such wells will result in any reserves or production. There is no guarantee that any internally estimated future potential development locations will be included and assigned reserves in any future reserves report prepared for the Company.

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, 2021 which is available on SEDAR at www.sedar.com.

SOURCE Paramount Resources Ltd.

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