Paramount Resources Ltd.

Paramount Resources Ltd. Reports 2020 Annual Results and Provides 2021 Guidance

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HIGHLIGHTS

- Annual sales volumes averaged 68,340 Boe/d (39% liquids) in 2020. Fourth quarter 2020 sales volumes averaged 73,460 Boe/d (42% liquids), ahead of guidance of 70,000 to 72,000 Boe/d.[1]
  - Fourth quarter sales volumes at Karr, which benefitted from bringing onstream the five-well 5-16 West pad in November, averaged 26,914 Boe/d (56% liquids), compared to 19,246 Boe/d (57% liquids) in the third quarter.
  - Fourth quarter sales volumes at Wapiti averaged 10,764 Boe/d (64% liquids), compared to 7,925 Boe/d (63% liquids) in the third quarter. The Company brought five new wells onstream on the 5-3 West pad during the fourth quarter.
- Cash from operating activities was $81 million in 2020 and $53 million in the fourth quarter. Adjusted funds flow in 2020 was $150 million or $1.12 per share. Fourth quarter 2020 adjusted funds flow was $68 million or $0.51 per share.[2]
- Capital spending in 2020 totaled $221 million, below guidance of $225 million. Fourth quarter 2020 capital spending was $65 million, resulting in free cash flow of $3 million in the quarter.[2]
- Abandonment and reclamation expenditures in 2020 totaled $35 million. In addition, approximately $4 million of activities were funded through government programs. Activities included the abandonment of 254 inactive wells, 236 of which were abandoned under the Company's ongoing area-based closure program at Hawkeye and Zama.
- Based on Paramount's strong financial and operational performance, in March 2021 the Company elected to exit the covenant relief period under its $1.0 billion bank credit facility prior to the scheduled expiry of the period on June 30, 2021.

(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 specific product type 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.
(2) "Adjusted funds flow" and "free cash flow" are Non-GAAP financial measures. See "Non-GAAP Financial Measures" in the Advisories section.

- The Company exceeded its previously announced 2020 cost reduction targets of $25 million in operating costs and $15 million in general and administrative expenses ("G&A").
  - Operating costs were $0.62/Boe lower in 2020 than in 2019, averaging $11.88/Boe in 2020. Fourth quarter operating costs were $11.80/Boe and included unbudgeted workovers on five wells in Karr, which partially contributed to fourth quarter production outperformance.
  - G&A costs were approximately $20 million ($0.43/Boe) lower in 2020 than in 2019, averaging $1.31/Boe in 2020.
- The Company successfully closed non-core asset dispositions for cash proceeds of approximately $80 million in the first quarter of 2021. The estimated impact to average 2021 production is approximately 2,600 Boe/d (15 MMcf/d of conventional natural gas and 135 Bbl/d of NGLs).

GRANDE PRAIRIE ACTIVITIES AND PERFORMANCE

- At Karr, a total of 15 new Montney wells were brought on production in the second half of 2020 following completion of an expansion to the third-party Karr 6-18 facility in July.
  - The five-well 12-18 pad and the five-well 2-1 pad were brought on production in the third quarter. These 10 wells averaged 1,502 Boe/d (3.6 MMcf/d of shale gas and 905 Bbl/d of NGLs) of peak 30-day wellhead production per well, with an average condensate to gas ratio ("CGR") of 253 Bbl/MMcf.[1]

- The five-well 5-16 West pad was brought onstream in November 2020. These wells averaged 1,617 Boe/d (3.7 MMcf/d of shale gas and 1,002 Bbl/d of NGLs) of peak 30-day wellhead production per well, with an average CGR of 271 Bbl/MMcf.[(1)]

- Six new Montney wells on the 3-10 pad at Karr were brought onstream in February 2021, two months ahead of schedule. The wells averaged 1,850 Boe/d (5.1 MMcf/d of shale gas and 1,000 Bbl/d of NGLs) of raw wellhead production per well over the first 20 days of production with an average CGR of 196 Bbl/MMcf.[(1)]

- At Wapiti, five Montney wells on the 5-3 West pad were brought onstream in 2020 and averaged 1,271 Boe/d (2.7 MMcf/d of shale gas and 827 Bbl/d of NGLs) of peak 30-day wellhead production per well, with an average CGR of 311 Bbl/MMcf.[(2)] A pre-existing tenure well was also brought onstream.

- Through a continued focus on innovation, technological advancement and efficient execution, the Company realized significant cost savings in its 2020 capital program without compromising deliverability from new wells. Cost savings have been achieved across many aspects of the capital program through improvements in well design, drill bit technology, fluid selection and reducing vendor rates.

  - All-in lease construction, drilling, completion, equip and tie-in (collectively, "DCET") costs for the five-well Karr 5-16 West pad averaged $7.5 million per well.

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 7% and liquids sales volumes are lower by approximately 7% 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. CGRs are calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See Oil and Gas Measures and Definitions in the Advisories section.

(2) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 15% and liquids sales volumes are lower by approximately 3% 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. CGRs are calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See Oil and Gas Measures and Definitions in the Advisories section.

  - Drilling of the six-well Karr 3-10 pad finished ahead of schedule allowing the Company to accelerate completion operations into 2020. Preliminary DCET costs averaged a pacesetting $7.0 million per well.

  - DCET costs for the last four pads (comprised of 21 wells) at Karr averaged approximately $7.5 million per well. As a consequence of structural cost improvements, the Company is revising downward its internal Karr type well DCET cost assumption to $7.5 million from the previous assumption of $8.4 million, the latter of which was used by the Company's independent third-party reserves evaluator in the preparation of the 2020 reserves report.[(1)]

  - At Wapiti, DCET costs on the five-well 5-3 West pad averaged $7.6 million per well. This represents a 27% reduction compared with average DCET costs for the initial two Wapiti pads and is consistent with Paramount's internal type well DCET cost assumption for Wapiti of $7.9 million, which was also used by the Company's independent third-party reserves evaluator in the preparation of the 2020 reserves report. [(1)]

2021 GUIDANCE

The Company's capital budget for 2021 is expected to range between $230 million and $260 million, excluding land acquisitions and abandonment and reclamation activities. Over 60% of the capital budget will be incurred in the first half of 2021. Approximately 85% of the 2021 program will be focused on advancing the Company's liquids-rich Montney developments at Karr and Wapiti. Approximately 70% of the 2021 capital budget is being allocated to sustaining capital and maintenance activities and the remaining 30% to production growth.

- At Karr, Paramount plans to drill 21 Montney wells and bring onstream a total of 19 wells in 2021. The six-well 3-10 pad was brought on production in February 2021, and the Company is currently drilling the three-well 4-28 East pad and the five-well 7-18 Pad that are expected to be onstream late in the second quarter and third quarter, respectively. The Company also plans to drill and bring onstream the five-well 5-16 East pad by the end of the third quarter and begin drilling the ten-well 16-17 pad during the fourth quarter.

- At Wapiti, the Company is currently drilling the remaining four Montney wells on the seven-well 6-4 pad. All seven wells are expected to be brought onstream starting in the third quarter of 2021. The Company also plans to drill a tenure well at Wapiti in 2021.

- Other key activities include a two-well Duvernay pad at Willesden Green, completion of a single well at Ante Creek (Montney oil) and the initiation of an enhanced oil recovery pilot at the Kaybob North Montney oil pool.

The Company expects 2021 sales volumes to average between 77,000 Boe/d and 80,000 Boe/d (45% liquids), slightly higher than preliminary guidance after accounting for first quarter dispositions of approximately 2,600 Boe/d of annualized production. [(2)]

- First half 2021 sales volumes are expected to average between 74,000 Boe/d and 76,000 Boe/d (43% liquids) as the majority of new wells will be brought on later in the year and volumes will be impacted by a scheduled outage at Karr in the second quarter.
- Despite a scheduled outage at Wapiti in the third quarter, second half 2021 sales volumes are expected to increase to average between 80,000 Boe/d and 84,000 Boe/d (46% liquids) as additional liquids-rich wells are brought onstream.

(1) Readers are referred to the advisories concerning "Reserves Data" in the Advisories section of this document.
(2) See the Product Type Information section for further information respecting the composition of forecast sales volumes.

The Company forecasts 2021 free cash flow of approximately $160 million based on: (i) the midpoint of forecast capital spending and production, (ii) $25 million in abandonment and reclamation costs, (iii) realized pricing of $39.50/Boe (US$58.60/Bbl WTI, US$3.00/MMBtu NYMEX, $2.80/GJ AECO), (iv) operating costs of $11.65/Boe, and (v) transportation and processing costs of $4.00/Boe. With approximately 57% of forecast midpoint 2021 production hedged, forecast free cash flow would still be approximately $100 million at an average 2021 WTI oil price of US$43.50/Bbl.[(1)]

The Company has budgeted approximately $31 million for abandonment and reclamation activities in 2021. Approximately $6 million is to be funded directly through the Alberta Site Rehabilitation Program ("ASRP"), resulting in approximately $25 million net to Paramount. The majority of these funds will be directed to the Zama area.

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

RESERVES [(1)]

- Despite a significant reduction in commodity price assumptions used by the independent third-party reserves evaluator, Paramount's 2020 proved plus probable ("P+P") reserves were unchanged versus 2019 at 632 MMBoe while proved developed producing ("PDP") reserves increased by 8% to 121 MMBoe. This reflects the Company's success in sustainably reducing both its operating and capital cost structure, as well as improvements in well performance. Optimizing Paramount's 5-year capital program resulted in a 2020 total proved ("TP") reserves decrease of 7% to 311 MMBoe compared to 335 MMBoe in 2019.
- Total undiscounted future development costs were reduced by $962 million for TP reserves and by $1,196 million for P+P reserves. Further reductions may be realized if actual DCET costs continue to be lower than the costs used by the Company's independent third-party reserves evaluator in 2020.
- The liquids weighting of the Company's 2020 reserves remain largely unchanged from 2019 (P+P 53% natural gas, 39% condensate and oil, 8% other NGLs).
- The Company's reserves replacement ratio was 1.4x for PDP reserves.
- PDP finding and development costs were $6.31/Boe in 2020.
- Estimated future net revenue at December 31, 2020, discounted at 10% before tax, totaled $1.9 billion for TP reserves and $3.6 billion for P+P reserves.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

Paramount has a long history of sustainable resource development and environmental stewardship and is committed to creating value for our stakeholders in an environmentally and socially responsible manner. Environmental, Social and Governance ("ESG") highlights in 2020 include:

- Publication of the Company's inaugural ESG report, which is available on Paramount's website at http://www.paramountres.com.
- Participation in the 2020 CDP Climate Change Survey.
- Completion of a multi-year project to replace approximately 1,900 high vent controllers with modern low or no vent units, reducing Paramount's annual greenhouse gas emissions by an estimated 75,000 tonnes of carbon dioxide equivalent ("tCO_2e"). Information about Paramount's other emissions reduction activities can be found in our ESG report.
- Paramount has implemented a corporate pandemic response plan aimed at ensuring the health and safety of its

staff and contractors and the people they come in contact with. The Company is conducting its operations in compliance with public health requirements and guidelines, including providing additional personal protective equipment and restricting access to its work sites to critical personnel.

(1) Readers are referred to the advisories concerning "Reserves Data" and "Oil and Gas Measures and Definitions" in the Advisories section of this document. Reserves evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel") as of December 31, 2020 and December 31, 2019 in accordance with National Instrument 51-101 definitions, standards and procedures. Reserves are gross reserves representing working interest before royalties. Net present values of future net revenue were determined using forecast prices and costs and do not represent fair market value.

CORPORATE

- To provide greater certainty of free cash flow levels and the funding of the Company's 2021 capital program, Paramount has hedged approximately 57% of its 2021 forecast production. The Company's current 2021 hedging position is summarized below:
    - Natural Gas: approximately 67,400 MMBtu/d at US$2.73/MMBtu and approximately 89,200 GJ/d at CDN$2.53/GJ over 2021.
    - Oil: approximately 18,100 Bbl/d at US$46.35/Bbl in 2021 and 3,000 Bbl/d at CDN$65.29/Bbl in the second and third quarters.
    - Condensate: 1,000 Bbl/d at US$WTI plus US$0.50/Bbl in the first quarter and 4,000 Bbl/d at US$WTI plus US$0.06/Bbl in the second quarter.
- Paramount's natural gas diversification strategy 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 in the US Midwest.
- The Company's long-term debt at December 31, 2020 was $813 million. In January 2021, Paramount's $1.0 billion senior secured revolving bank credit facility was amended to remove prior conditions on facility availability in excess of $900 million. Concurrent with the amendments, the Company completed a private placement of $35 million of senior unsecured convertible debentures.
- In March 2021, the Company elected to exit the covenant relief period under its $1.0 billion bank credit facility prior to the scheduled expiry of the period on June 30, 2021.

FINANCIAL AND OPERATING RESULTS (1)
($ millions, except as noted)

	Three months ended December 31		Twelve months ended December 31	
	2020	**2019**	**2020**	**2019**
Net income (loss)	**311.5**	(31.1)	**(22.7)**	(87.9)
per share – basic and diluted ($/share)	***2.35***	*(0.24)*	***(0.17)***	*(0.67)*
Cash from operating activities	**53.2**	70.5	**80.9**	255.7
per share – basic and diluted ($/share)	***0.40***	*0.54*	***0.61***	*1.96*
Adjusted funds flow	**67.9**	93.5	**150.0**	299.0
per share – basic and diluted ($/share)	***0.51***	*0.71*	***1.12***	*2.29*
Total assets			**3,497.0**	3,531.3
Long-term debt			**813.5**	632.3
Net debt			**854.1**	703.5
Common shares outstanding *(thousands)* (2)			**132,284**	133,337
Sales volumes				
Natural gas (MMcf/d)	**256.3**	299.0	**248.7**	303.3
Condensate and oil (Bbl/d)	**25,752**	28,516	**22,565**	25,079
Other NGLs (Bbl/d) (3)	**4,987**	7,064	**4,325**	6,767
Total (Boe/d)	**73,460**	85,411	**68,340**	82,394
% liquids	***42%***	*42%*	***39%***	*39%*
Grande Prairie Region (Boe/d)	**37,782**	36,789	**31,076**	29,040
Kaybob Region (Boe/d)	**27,056**	33,167	**28,685**	35,500
Central Alberta and Other Region				

(Boe/d)	**8,622**		15,455		**8,579**		17,854	
Total (Boe/d)	**73,460**		85,411		**68,340**		82,394	
Netback		***$/Boe (4)***		*$/Boe (4)*		***$/Boe (4)***		*$/Boe (4)*
Natural gas revenue	**66.7**	***2.83***	75.1	*2.73*	**204.9**	***2.25***	261.0	*2.36*
Condensate and oil revenue	**123.3**	***52.03***	175.0	*66.70*	**383.8**	***46.47***	610.2	*66.66*
Other NGLs revenue (3)	**9.5**	***20.61***	8.5	*13.03*	**24.7**	***15.63***	37.7	*15.24*
Royalty and other revenue	**2.5**	–	1.3	–	**12.6**	–	6.0	–
Petroleum and natural gas sales	**202.0**	***29.89***	259.9	*33.08*	**626.0**	***25.03***	914.9	*30.42*
Royalties	**(11.7)**	***(1.73)***	(17.2)	*(2.19)*	**(31.3)**	***(1.25)***	(63.3)	*(2.10)*
Operating expense	**(79.8)**	***(11.80)***	(105.0)	*(13.36)*	**(297.1)**	***(11.88)***	(376.0)	*(12.50)*
Transportation and NGLs processing (5)	**(24.6)**	***(3.63)***	(22.8)	*(2.90)*	**(101.3)**	***(4.05)***	(94.7)	*(3.15)*
Netback	**85.9**	***12.73***	114.9	*14.63*	**196.3**	***7.85***	380.9	*12.67*
Commodity contract settlements	**7.9**	***1.18***	4.7	*0.60*	**37.6**	***1.50***	13.2	*0.44*
Netback including commodity contract settlements	**93.8**	***13.91***	119.6	*15.23*	**233.9**	***9.35***	394.1	*13.11*
Total capital expenditures								
Grande Prairie Region (6)	**64.3**		60.7		**196.9**		302.2	
Kaybob Region	**1.8**		9.5		**16.4**		80.7	
Central Alberta and Other Region	**0.8**		0.6		**4.6**		7.6	
Corporate (7)	**(1.8)**		–		**2.3**		6.0	
Land and property acquisitions	–		1.4		**0.6**		7.6	
Total	**65.1**		72.2		**220.8**		404.1	
Asset retirement obligations settlements	**0.1**		18.0		**35.0**		29.4	

(1) Readers are referred to the advisories concerning Non-GAAP Measures and Oil and Gas Measures and Definitions in the Advisories section of this document. This table contains the following Non-GAAP measures: 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 specific product type.
(2) Common shares are presented net of shares held in trust under the Company's restricted share unit plan (000's of common shares): 2020: 1,914; 2019: 860; 2018: 574.
(3) Other NGLs means ethane, propane and butane.
(4) Natural gas revenue presented as $/Mcf.
(5) Includes downstream transportation costs and NGLs fractionation costs.
(6) Total capital expenditures for the year ended December 31, 2019 includes $45.5 million of capital spending related to the Karr 6-18 natural gas facility prior to its sale (three months ended December 31, 2019 – nil).
(7) Corporate capital expenditures includes transfers between regions.

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 2020 annual results, including the Review of Operations, Management's Discussion and Analysis and the Company's Consolidated Financial Statements can be obtained at: https://mma.prnewswire.com/media/1448762/Paramount_Resources_Ltd__Paramount_Resources_Ltd__Reports_2020_A.pdf. A summary of historical financial and operating results is also available on Paramount's website at http://www.paramountres.com/investor-relations/financial-reports#2020.

This information will also be made available through Paramount's website at www.paramountres.com and on SEDAR at www.sedar.com.

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 specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil. Numbers may not add due to rounding.

	Annual							
	Total		Grande Prairie Region		Kabob Region		Central Alberta and Other Region	
	2020	2019	2020	2019	2020	2019	2020	2019
Shale gas (MMcf/d)	**156.7**	166.0	**77.2**	78.0	**43.8**	50.3	**35.7**	37.7
Conventional natural gas (MMcf/d)	**92.0**	137.3	**1.4**	1.5	**82.1**	95.9	**8.5**	39.9
Natural gas (MMcf/d)	**248.7**	303.3	**78.6**	79.5	**125.9**	146.2	**44.2**	77.6
Condensate (Bbl/d)	**19,334**	19,746	**15,991**	13,920	**2,885**	4,361	**458**	1,464
Other NGLs (Bbl/d)	**4,325**	6,767	**1,964**	1,814	**1,812**	2,476	**549**	2,477
NGLs (Bbl/d)	**23,659**	26,513	**17,955**	15,734	**4,697**	6,837	**1,007**	3,941
Tight oil (Bbl/d)	**462**	631	**–**	–	**301**	360	**161**	271
Light and Medium crude oil (Bbl/d)	**2,768**	4,703	**14**	53	**2,709**	3,929	**46**	721
Crude oil (Bbl/d)	**3,230**	5,334	**14**	53	**3,010**	4,289	**207**	992
Total (Boe/d)	**68,340**	82,394	**31,076**	29,040	**28,685**	35,500	**8,579**	17,854

	Q4							
	Total		Grande Prairie Region		Kabob Region		Central Alberta and Other Region	
	2020	2019	2020	2019	2020	2019	2020	2019
Shale gas (MMcf/d)	**170.7**	176.6	**92.7**	91.5	**41.9**	48.3	**36.1**	36.8
Conventional natural gas (MMcf/d)	**85.6**	122.4	**1.6**	1.9	**76.3**	89.1	**7.7**	31.4
Natural gas (MMcf/d)	**256.3**	299.0	**94.3**	93.4	**118.2**	137.4	**43.8**	68.2
Condensate (Bbl/d)	**22,782**	23,956	**19,635**	18,760	**2,631**	3,899	**515**	1,298
Other NGLs (Bbl/d)	**4,987**	7,064	**2,429**	2,376	**1,953**	2,504	**605**	2,184
NGLs (Bbl/d)	**27,769**	31,020	**22,064**	21,136	**4,584**	6,403	**1,120**	3,482
Tight oil (Bbl/d)	**437**	745	**–**	–	**299**	541	**138**	203
Light and Medium crude oil (Bbl/d)	**2,533**	3,815	**–**	91	**2,480**	3,331	**54**	393
Crude oil (Bbl/d)	**2,970**	4,560	**–**	91	**2,779**	3,872	**192**	596
Total (Boe/d)	**73,460**	85,411	**37,782**	36,789	**27,056**	33,167	**8,622**	15,455

Fourth quarter 2020 sales volumes at Karr averaged 26,914 Boe/d (69.6 MMcf/d of shale gas, 0.9 MMcf/d of conventional natural gas and 15,165 Bbl/d of NGLs), compared to 19,246 Boe/d (48.6 MMcf/d of shale gas, 0.6 MMcf/d of conventional natural gas and 11,044 Bbl/d of NGLs) in the third quarter of 2020. Fourth quarter 2020 sales volumes at Wapiti averaged 10,764 Boe/d (22.8 MMcf/d of shale gas, 0.5 MMcf/d of conventional natural gas and 6,875 Bbl/d of NGLs), compared to 7,925 Boe/d (17.4 MMcf/d of shale gas, 0.4 MMcf/d of conventional natural gas and 4,962 Bbl/d of NGLs) in the third quarter of 2020.

The Company forecasts that 2021 sales volumes will average between 77,000 Boe/d and 80,000 Boe/d (55% shale gas and conventional natural gas combined, 39% light and medium crude oil, tight oil and condensate combined and 6% other NGLs). First half 2021 sales volumes are expected to average between 74,000 Boe/d and 76,000 Boe/d (57% shale gas and conventional natural gas combined, 37% light and medium crude oil, tight oil and condensate combined and 6% other NGLs). Second half 2021 sales volumes are expected to increase to average between 80,000 Boe/d and 84,000 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).

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:

- planned capital expenditures for 2021 and the timing and allocation thereof;
- forecast sales volumes for 2021 and certain periods within 2021;
- forecast free cash flow in 2021;
- planned exploration, development and production activities, including the expected timing of completing and bringing new wells on production;
- planned abandonment and reclamation expenditures and activities in 2021 and anticipated funding under the ASRP;
- planned facility outages and turnarounds;
- the potential to realize further reductions in future development costs if actual DCET costs continue to be lower than the costs used by the Company's independent third-party reserves evaluator in 2020; and

- expected GHG reductions associated with controller upgrades.

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

- future natural gas and liquids prices 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 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 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).

Statements relating to reserves are also deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

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

- fluctuations in natural gas and liquids prices, including in relation to the impact of the COVID-19 pandemic;
- 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, reserve additions, liquids yields (including condensate to natural gas ratios), resource recoveries, royalty rates, taxes and costs and expenses;
- the ability to secure adequate product processing, transportation, fractionation, and storage capacity on acceptable terms;
- operational risks in exploring for, developing, producing and transporting natural gas and liquids, including the risk of spills, leaks or blowouts;
- the ability to obtain equipment, services, supplies and personnel in a timely manner and at an acceptable cost;
- potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities (including third-party facilities);
- processing, pipeline, and fractionation infrastructure outages, disruptions and constraints;
- risks and uncertainties involving the geology of oil and gas deposits;
- the uncertainty of reserves estimates;
- general business, economic and market conditions;
- the ability to generate sufficient cash flow from operations and obtain financing to fund planned exploration, development and operational activities and meet current and future commitments and obligations (including product processing, transportation, fractionation and similar commitments and obligations);
- changes in, or in the interpretation of, laws, regulations or policies (including environmental laws);
- the ability to obtain required governmental or regulatory approvals in a timely manner, and to obtain and maintain leases and licenses;
- the effects of weather and other factors including wildlife and environmental restrictions which affect field operations and access;
- the timing and cost of future abandonment and reclamation obligations and potential liabilities for environmental damage and contamination;
- uncertainties regarding aboriginal claims and in maintaining relationships with local populations and other stakeholders;
- the outcome of existing and potential lawsuits, 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.

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.

Non-GAAP Financial Measures

In this press release, "Adjusted funds flow", "Netback", "Free cash flow", "Net Debt" and "Total Capital Expenditure", together the "Non-GAAP financial measures", are used and do not have any standardized meanings as prescribed by International Financial Reporting Standards. Certain comparative figures have been reclassified to conform to the current years' presentation.

"Adjusted funds flow" refers to cash from operating activities before net changes in non-cash working capital, geological and geophysical expenses, asset retirement obligation settlements, closure costs, transaction and reorganization costs, provision and other and dispute settlements. 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 and twelve months ended December 31, 2020 and December 31, 2019:

Year ended December 31	2020 (MM$)	2019 (MM$)
Cash from operating activities	**80.9**	**255.7**
Change in non-cash working capital	17.9	(15.9)
Geological and geophysical expenses	8.5	11.0
Asset retirement obligations settled	35.0	29.4
Closure costs	–	14.0
Transaction and reorganization costs	3.0	2.3
Provision and other	4.7	2.5
Adjusted funds flow	**150.0**	**299.0**

Three months ended December 31	2020 (MM$)	2019 (MM$)
Cash from operating activities	**53.2**	**70.5**
Change in non-cash working capital	12.5	(8.0)
Geological and geophysical expenses	2.1	3.5
Asset retirement obligations settled	0.1	18.0
Closure costs	–	4.7
Transaction and reorganization costs	–	2.3
Dispute settlements	–	2.5
Adjusted funds flow	**67.9**	**93.5**

"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 December 31, 2020:

Three months ended December 31	2020 (MM$)
Cash from operating activities	**53.2**
Change in non-cash working capital	12.5
Geological and geophysical expenses	2.1
Asset retirement obligations settled	0.1
Closure costs	–
Transaction and reorganization costs	–
Provision and other	–
Adjusted funds flow	**67.9**

Total capital expenditures	(65.1)
Asset retirement obligation settlements	(0.1)
Free cash flow	**2.7**

"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 table under the heading "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 year ended December 31, 2020 (the "MD&A") for the calculation of Net Debt.

"Total capital expenditures" refers to the Company's property, plant and equipment and exploration expenditures. Refer to the Property, Plant and Equipment and Exploration 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.

Reserves Data

Reserves data set forth in this press release is based upon an evaluation of the Company's reserves prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") dated March 2, 2021 and effective December 31, 2020 (the "McDaniel Report"). The price forecast used in the McDaniel Report is an average of the January 1, 2021 price forecasts for McDaniel and GLJ Petroleum Consultants Ltd. and the December 31, 2020 price forecast of Sproule Associates Ltd. The estimates of reserves contained in the McDaniel Report and referenced in this press release are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates contained in the McDaniel Report and referenced in this press release. There is no assurance that the forecast prices and costs assumptions used in the McDaniel Report will be attained, and variances could be material. Estimated future net revenue does not represent fair market value. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. Readers should refer to the Company's annual information form for the year ended December 31, 2020, which is available on SEDAR at www.sedar.com, for a complete description of the McDaniel Report (including reserves by specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil) and the material assumptions, limitations and risk factors pertaining thereto.

Oil and Gas Measures and Definitions

Abbreviations

Liquids		**Natural Gas**	
Bbl	Barrels	GJ	Gigajoules
Bbl/d	Barrels per day	GJ/d	Gigajoules per day
MBbl	Thousands of barrels	Mcf	Thousands of cubic feet
NGLs	Natural gas liquids	MMcf	Millions of cubic feet
Condensate	Pentane and heavier hydrocarbons	MMcf/d	Millions of cubic feet per day
		AECO	AECO-C reference price
Oil Equivalent		WTI	West Texas Intermediate
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", "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 year ended December 31, 2020, the value ratio between crude oil and natural gas was approximately 21:1. This value ratio is significantly different from the energy equivalency ratio of 6:1. Using a 6:1 ratio would be misleading as an indication of value.

This press release contains metrics commonly used in the oil and natural gas industry. Each of these metrics is determined by the Company as set out below or elsewhere in this press release. The metrics are "CGR", "reserves replacement ratio" and "finding and development costs". These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies. As such, they should not be used to make comparisons. Management uses these 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.

"CGR" means condensate to gas ratio and is calculated by dividing wellhead raw liquids volumes by wellhead raw natural gas volumes.

"Reserves replacement ratio" is calculated by dividing: (i) the net changes in reserves from the prior year from extensions/improved recovery, technical revisions and economic factors, by (ii) the aggregate production during the year. Reserves replacement ratio is a measure commonly used by management and investors to assess the rate at which reserves depleted by production are being replaced by reserves added through operations.

"Finding and development costs" are calculated by dividing: (i) total capital expenditures for the period (excluding corporate expenditures and land and property acquisitions) by (ii) the net changes in reserves from the prior year from extensions/improved recovery, technical revisions and economic factors. Finding and development costs are a measure commonly used by management and investors to assess the relationship between capital invested in oil and gas exploration and development projects and reserve additions associated with such projects.

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.

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For further information: Paramount Resources Ltd., J.H.T. (Jim) Riddell, President and Chief Executive Officer and Chairman; Paul R. Kinvig, Chief Financial Officer; Rodrigo (Rod) Sousa, Executive Vice President, Corporate Development and Planning, www.paramountres.com, Phone: (403) 290-3600
